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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 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) **December 5, 2003**

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.)
901 Marquette Avenue, Suite 2300 Minneapolis, MN	**55402**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **612-373-5300**

(Former name or former address, if changed since last report)

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Item 5. Other Events

NRG Energy, Inc. announced on December 5, 2003 that it has successfully completed its Chapter 11 reorganization and has emerged from bankruptcy. NRG filed its Chapter 11 petition less than seven months earlier, on May 14. The U.S. Bankruptcy Court for the Southern District of New York confirmed NRG's Plan of Reorganization on November 24 and all conditions have been met clearing the way for NRG to emerge from Chapter 11.

Through the reorganization process, NRG eliminated corporate level debt and other claims totaling more than $6 billion. NRG emerges with $510 million of corporate debt and approximately $4.4 billion in project level debt. Under its plan of reorganization, NRG will issue 100 million shares of common stock in the reorganized company. Creditors will receive a combination of cash, common stock and $500 million of newly issued corporate notes, which are reflected in the debt totals stated above. NRG expects to announce timing of the distribution of the common shares, notes and cash shortly.

Item 7. Financial Statements and Exhibits.

The following exhibits are filed with this report on Form 8-K:

Exhibit No.	Description
99.1	Press Release
99.2	Current information regarding NRG Energy, Inc.

Item 9. Regulation FD Disclosure.

The information set forth in Exhibit 99.2 of this Current Report on Form 8-K is being furnished to the Commission in order to satisfy NRG Energy, Inc.'s obligations under Regulation FD. The furnishing of this information shall not be deemed to be an admission that all or any portion of it is material.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

NRG Energy, Inc. (Registrant)

By /s/ George P. Schaefer

George P. Schaefer
Vice President and Treasurer

Dated: December 8, 2003

EXHIBIT 99.1

NRG Energy, Inc.
901 Marquette Avenue, Suite 2300
Minneapolis, MN 55402
Phone: 612.373.6992 • Fax: 612.373.8699
http://www.nrgenergy.com

NEWS RELEASE

NRG ENERGY, INC. COMPLETES REORGANIZATION AND EMERGES FROM CHAPTER 11; APPOINTS NEW BOARD OF DIRECTORS

MINNEAPOLIS; DECEMBER 05, 2003) — NRG Energy, Inc. (NRG) today announced that it has successfully completed its Chapter 11 reorganization and has emerged from bankruptcy. NRG filed its Chapter 11 petition less than seven months earlier, on May 14. The U.S. Bankruptcy Court for the Southern District of New York confirmed NRG's Plan of Reorganization on November 24 and all conditions have been met clearing the way for NRG to emerge from Chapter 11.

Through the reorganization process, the Company eliminated corporate level debt and other claims totaling more than $6 billion. NRG emerges with $510 million of corporate debt and approximately $4.4 billion in project level debt. Under the Plan, the Company will issue 100 million shares of common stock in the reorganized company. Creditors will receive a combination of cash, common stock and $500 million of newly issued corporate notes, which are reflected in the debt totals stated above. The company expects to announce timing of the distribution of the common shares, notes and cash shortly.

"This is a significant day for NRG," said David Crane, newly appointed NRG President and Chief Executive Officer. "We've accomplished a complex restructuring in a remarkably short period of time and are pleased to be the first in the industry to complete a comprehensive financial restructuring and deleveraging of the debt on our balance sheet."

Effective upon today's emergence, NRG's new Board of Directors will be comprised of Crane, seven independent directors and three members of investment firm MatlinPatterson Global Advisers LLC. The Board members are:

- **David Crane**, NRG President and Chief Executive Officer;
- **Howard Cosgrove**, the non executive Chairman of the NRG Board, is the retired Chairman and Chief Executive Officer of Conectiv and its predecessor, Delmarva Power and Light. He is Chairman of the Board of Trustees at the University of Delaware and he also serves on the Board of Henlopen Mutual Fund;
- **Ramon Betolaza**, is a Partner with MatlinPatterson a global private equity fund. Betolaza is also a Director of Opus Energy and Polymer Group, Inc.;
- **John Chlebowski** is President and Chief Executive Officer of Lakeshore Operating Partners, LLC, a bulk liquid distribution firm. He also serves on the Laidlaw International Inc. Board of Directors and PRP-GP LLC.;
- **Lawrence Coben** is Senior Principal of Sunrise Capital Partners, a private equity firm and is a Director of Prisma Energy;
- **Stephen Cropper** spent 25 years with The Williams Companies, before retiring in 1998 as President and Chief Executive Officer of Williams Energy Services. Cropper serves on a number of Corporate Boards including Berry Petroleum Company and Heritage Propane Partners;
- **Mark Patterson** is Chairman of MatlinPatterson. Patterson previously served as Vice Chairman of Credit Suisse First Boston Corporation. He serves as a Director for Oxford Automotive and Compass Aerospace as well as Eon Labs Inc.;
- **Frank Plimpton**, a Partner at MatlinPatterson is also a Director of RailWorks Corporation and Oxford Automotive;

- **Herbert Tate**, Counsel with Wolf & Samson P.C. law firm and previously served as President of the New Jersey Board of Public Utilities. He is also a Director of IDT Solutions and Winstar Telecommunications;
- **Walter Young**, recently retired from his position as Chairman, Chief Executive Officer and President of Champion Enterprises, Inc., a producer and seller of manufactured homes;
- **Thomas Weidemeyer** is Senior Vice President and Chief Operating Officer of United Parcel Service, Inc. Weidemeyer also serves as a Director for UPS.

NRG noted that its power marketing unit, NRG Power Marketing, Inc. also emerged from Chapter 11 protection today. NRG expects its NRG Northeast Generating LLC and South Central Generation Holding LLC operating subsidiaries to emerge from Chapter 11 subsequent to the completion of a debt refinancing. As of NRG's emergence, Xcel Energy no longer owns any portion of the company.

NRG Energy, Inc. owns and operates a diverse portfolio of power-generating facilities, primarily in the United States. Its operations include competitive energy production and cogeneration facilities, thermal energy production and energy resource recovery facilities.

Certain statements included in this news release are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements above include, but are not limited to, timing of distributions of stock cash and notes in accordance with the Plan, and completion of a debt financing. Although NRG believes that its expectations are reasonable, it can give no assurance that these expectations will prove to have been correct. Factors that could cause NRG's actual results to differ materially from those contemplated in the forward-looking statements above include, among others, the possibility that distributions of cash stock and notes pursuant to the Plan will be delayed or that the debt refinancing will be delayed or not be completed.

The foregoing review of factors that could cause NRG's actual results to differ materially from those contemplated in the forward-looking statements included in this news release should not be construed as exhaustive. For more information regarding risks and uncertainties that may affect NRG's future results, review NRG's filings with the Securities Exchange Commission.

# # #

Contacts: Lesa Bader, 612.373.6992

Exhibit 99.2

SUMMARY

The following summary does not contain all the information that may be important to you and is qualified in its entirety by the more detailed information appearing elsewhere in this report. You should read the entire report, especially the risks set forth under the heading “Risk Factors”. In this report, unless the context requires otherwise: (i) “NRG Energy,” “NRG,” “Company,” “we,” “us” and “our” refer to NRG Energy, Inc. and its subsidiaries. All references to “MW” in this report give effect to NRG’s net ownership percentage in the applicable region or of the applicable facility.

Overview of NRG

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 helps us mitigate risk. We intend to maximize operating income through the efficient procurement and management of fuel supplies and maintenance services, and the sale of energy, capacity and ancillary services into attractive spot, intermediate and long-term markets. On a pro forma basis after giving effect to the Reorganization Events and the Refinancing Transactions (each as defined hereafter), we generated total operating revenues and equity earnings of approximately $2.3 billion and Pro Forma Adjusted EBITDA of approximately $549.7 million for the twelve-month period ending September 30, 2003.

As of September 30, 2003, we owned interests in 86 power projects in eight countries having an aggregate generation capacity of approximately 18,300 MW. Approximately 8,300 MW of our capacity consists of merchant power plants in the Eastern region of the United States. Certain of these assets are located in transmission constrained areas, including approximately 1,400 MW of “in-city” New York City generation capacity and approximately 700 MW of southwest Connecticut generation capacity. We also own approximately 5,600 MW of capacity in the Central region of the United States, with approximately 3,000 MW of that capacity supported by long-term power purchase agreements. Our assets in the Western region of the United States consist of approximately 1,300 MW of capacity, with the majority of such capacity owned via our 50% interest in West Coast Power LLC, or “West Coast Power.” Our assets in the Western region are supported by a power purchase agreement with the California Department of Water Resources that runs through December 2004. As of September 30, 2003, our principal domestic generation assets consisted of a diversified mix of natural gas-, coal-and oil-fired facilities, representing approximately 48%, 26% and 26% of our total domestic generation capacity, respectively. We also own interests in plants having a generation capacity of approximately 3,100 MW in various international markets, including Australia, Europe and Latin America. Our energy marketing subsidiary, NRG Power Marketing Inc., or “PMI,” began operations in 1998 and is focused on maximizing the value of our North American assets by providing centralized contract origination and management services, and through the efficient procurement and management of fuel and the sale of energy and related products in the spot, intermediate and long-term markets.

Strategy

We own and operate a diverse portfolio of electric generation facilities which we believe have strategic locational advantages. Through our reorganization, we intend to reposition ourselves in our industry to focus on owning, operating and maximizing the value of our generation assets. We are implementing this strategy through the following key actions:

- optimizing the value of our existing assets with a focus on operational reliability and efficiency;
- retaining a new management team with proven industry experience;
- balancing risk by pursuing asset-focused power marketing activities through effective procurement of fuel and fuel services and the sale of energy and related products into spot, intermediate and long-term markets;

• improving our liquidity position and further deleveraging our balance sheet; and

• limiting acquisitions and new project developments in the near term.

Competitive Strengths

We believe that we benefit from the following competitive strengths:

Plant Diversity. Our generation fleet in each regional market includes base-load, intermediate and peaking facilities, which helps maximize our profit opportunities along the entire energy dispatch curve. Our generation facilities are likewise diversified by fuel-type, including coal, oil and natural gas. The diversity of technology, fuel type and operational characteristics allows us to participate in all aspects of the electricity demand cycle. By offering what we believe to be an efficient mix of generation, we are able to offer competitive prices to our customers and optimize the revenue potential across the entire fleet. For example, due to the recent volatility and price spikes of natural gas, our coal assets, such as Huntley, Dunkirk, Big Cajun II and Indian River, have a distinct competitive advantage due to the relatively low marginal cost of coal. Peaker assets provide increased revenue by taking advantage of higher prices in periods of increased demand in the energy markets. Further, peaking and intermediate assets can provide emergency back-up when our base-load plants experience outages.

Regional Strength. We have acquired a number of power plants in the Eastern, Central and Western regions of the United States, providing economies of scale throughout the organization and reducing our dependence on any single market. Owning multiple plants in a particular market provides us greater dispatch flexibility and increases power marketing opportunities.

Locational Advantages. We own and operate many facilities which are strategically located near large urban areas or in certain transmission-constrained areas with locational advantages over our competition. For example, the Astoria and Arthur Kill plants are ideally situated to serve the New York City market. Due to transmission constraints, competitors outside the city limits are restricted from importing power into New York City, and therefore do not have the advantage of “in city” generation. Certain facilities in California near the Los Angeles and San Diego load centers use ocean water cooling that gives them competitive advantages, especially during water shortages. Additionally, construction of new power plants in areas such as New York City and California is limited because of the difficulty in:

• finding sites for new plants;

• overcoming the general public’s “not-in-my-backyard” mentality;

• obtaining the necessary permits; and

• arranging fuel supplies.

In some locations, a facility’s advantage is also enhanced by the potential for re-powering the facility or site expansion.

Risk Mitigation. As a wholesale generator, we are subject to the risks associated with volatility in fuel and power prices. We mitigate these risks by managing a portfolio of contractual assets for both power supply and fuel requirements. In the near term our portfolio will be weighted toward spot market sales and short-term contracts because long-term contracts are not currently available at attractive prices. We expect that these generally weak market conditions will continue for the foreseeable future in some markets. As the markets improve, we will seek opportunities to enter into longer-term agreements in order to capture more stable returns and predictable cash flow. We continuously monitor counterparty credit risk, and when necessary seek appropriate credit support in the form of cash collateral or letters of credit.

Improved Financial Position. As part of our plan of reorganization, we are eliminating 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, up to $540.0 million in cash and $500.0 million of new debt among our unsecured creditors. Since the implementation of our divestiture program in July 2002, we have successfully sold certain assets, eliminating approximately $1.2 billion of debt.

Recent Developments

On October 21, 2003, we announced the appointment of David W. Crane as our new President and Chief Executive Officer, effective December 1, 2003. Mr. Crane served as the Chief Executive Officer of London-based International Power PLC and has over 12 years of energy industry experience. He also served as its Chief Operating Officer. We have filled several other senior and middle management positions over the past 12 months. We are currently conducting a search for a new Chief Financial Officer. We anticipate the position will be filled in the months following our emergence from bankruptcy. Upon emergence from bankruptcy, our board of directors will initially consist of Mr. Crane and ten other individuals, three of whom have been designated by MatlinPatterson LLC, a private equity firm, or “MatlinPatterson,” and seven of whom will be independent. For more information, see “Management.”

The Plans of Reorganization

On May 14, 2003, NRG and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. On that date, we filed a plan of reorganization providing for the reorganization of five of the debtors: NRG Energy, Inc., NRG Power Marketing Inc., NRG Capital LLC, NRG Finance Company I LLC, or “NRG FinCo,” and NRGenerating Holdings (No. 23) B.V., which we collectively refer to as the “NRG Plan Debtors.” No international operations were included in the filing. The plan of reorganization for the NRG Plan Debtors, or the “NRG plan of reorganization,” generally provides for the elimination of 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, up to $540.0 million in cash and $500.0 million of new debt among our unsecured creditors.

On September 17, 2003, a plan of reorganization was filed for (i) NRG Northeast Generating LLC and its debtor subsidiaries, which we collectively refer to as “NRG Northeast,” (ii) NRG South Central Generating LLC and its debtor subsidiaries, which we collectively refer to as “NRG South Central,” and (iii) Berrians I Gas Turbine Power LLC, or “Berrians” and, collectively with NRG Northeast and NRG South Central, the “Northeast/ South Central Debtors.” The plan of reorganization for the Northeast/ South Central Debtors, or the “Northeast/ South Central plan of reorganization,” generally provides for payment in full to holders of allowed secured claims in cash on or around the effective date of the Northeast/ South Central plan of reorganization. Holders of allowed general unsecured claims will receive either (i) cash equal to the unpaid portion of their allowed unsecured claim, (ii) treatment that leaves unaltered the legal, equitable and contractual rights to which such unsecured claim entitles the holder of such claim, (iii) treatment that otherwise renders such unsecured claim unimpaired pursuant to section 1124 of the bankruptcy code or (iv) such other, less favorable treatment that is confirmed in writing as being acceptable to such holder and to the applicable debtor.

An order confirming the NRG plan of reorganization was entered by the bankruptcy court on November 24, 2003, and the plan became effective on December 5, 2003. On November 25, 2003, an order confirming the Northeast/ South Central plan of reorganization was entered by the bankruptcy court, and we anticipate that the Northeast/ South Central plan will become effective concurrently with the closing of this financing. Effectiveness of the Northeast/South Central plan is contingent, in part, on consummation of the Refinancing Transactions (as defined below).

For more information regarding the NRG and Northeast/ South Central plans of reorganization, see “The Bankruptcy Case.”

Upon the effective date of the NRG plan of reorganization, or shortly thereafter, we will, pursuant to such plan:

- cancel all of NRG Energy's existing capital stock and distribute to unsecured creditors a combination of up to $540.0 million in cash, new common stock of NRG and $500.0 million of our 10% Senior Unsecured Notes due 2010, which we refer to as the "Plan Notes;"
- issue to Xcel Energy a $10.0 million non-amortizing promissory note which will (a) accrue interest at a rate of 3% per annum and (b) mature two and one-half years after the effective date of the NRG plan of reorganization; and
- make adjustments to our consolidated financial statements for "fresh-start" reporting under GAAP.

A principal component of the NRG plan of reorganization is a settlement with Xcel Energy in which Xcel Energy has 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. We will distribute $515.0 million of cash we receive from Xcel Energy to our creditors. In the event we achieve certain liquidity measures in September 2004, an additional $25.0 million may be distributed to creditors, and we will use up to $100.0 million to redeem outstanding Plan Notes. In the event no Plan Notes are outstanding at that time, we may use such $100.0 million for any purpose, subject to any restrictions contained in the indenture or the New Credit Facility.

In this report, we refer to the effectiveness of the NRG plan of reorganization and the foregoing as the "Reorganization Events."

Please see "The Bankruptcy Case" section of this report for a more complete description of the bankruptcy case, the NRG plan of reorganization and the Northeast/ South Central plan of reorganization.

Summary Unaudited Pro Forma Consolidated Financial Data

The following table sets forth our summary pro forma consolidated financial data for the periods ended and at the date indicated below. The summary pro forma consolidated financial data for the fiscal year ended December 31, 2002 and the nine months ended September 30, 2003 give effect to the completion of the Reorganization Events, including the effectiveness of the NRG plan of reorganization and the effect of fresh-start accounting principles, and a series of transactions designed to refinance certain of our remaining items of indebtedness and to provide financing for our operations going forward (the "Refinancing Transactions").

The following summary pro forma consolidated financial data should be read in conjunction with "Unaudited Pro Forma Consolidated Financial Information," "Selected Historical Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements of NRG Energy, Inc. and the related notes thereto included elsewhere in this report.

	Pro Forma	
(Dollars in thousands)	Year Ended December 31, 2002	Nine Months Ended September 30, 2003
Income Statement Data:		
Operating Revenues and Equity Earnings:		
Revenues from majority-owned operations	$ 2,088,432	$ 1,616,869
Equity in earnings of unconsolidated affiliates	68,996	155,758
Total operating revenues and equity earnings	2,157,428	1,772,627
Operating Costs and Expenses:		
Cost of majority-owned operations	1,398,965	1,186,241
Depreciation and amortization	151,665	127,507
General, administrative and development expenses	226,528	128,010
Write downs and losses on sales of equity method investments	200,472	136,717
Legal settlement	—	396,000
Restructuring and impairment charges	2,627,766	298,019
Total operating costs and expenses	4,605,396	2,272,494
Operating (Loss)/ Income	(2,447,968)	(499,867)
Other Income (Expense):		
Minority interest in (earnings)/losses of consolidated subsidiaries	(1,290)	(2,415)
Other income, net	4,232	7,924
Interest expense	(240,495)	(227,117)
Total other expense	(237,553)	(221,608)
(Loss)/ Income From Continuing Operations Before Income Taxes	(2,685,521)	(721,475)
Income Tax (Benefit)/ Expense	(163,236)	44,864
(Loss)/ Income From Continuing Operations	$(2,522,285)	$ (766,339)

	Pro Forma
	At September 30, 2003
Balance Sheet Data (at period end):	
Cash and cash equivalents	$ 173,577
Restricted cash	737,644
Total assets	9,041,436
Total long-term debt, including current maturities	4,852,005
Stockholders' equity	2,403,865

Supplemental Summary Unaudited Consolidated Financial Data

The following table sets forth supplemental summary consolidated financial data at September 30, 2003 and for the twelve months ended September 30, 2003 to give effect to the completion of the Reorganization Events and the Refinancing Transactions, including the effectiveness of the NRG plan of reorganization and the effect of fresh-start accounting principles. We believe that the presentation of this supplemental summary unaudited consolidated financial data for the twelve months ended September 30, 2003 is appropriate to provide meaningful comparisons with other sources of data in our industry and related industries, since such data is usually presented on a twelve month basis.

The following summary consolidated financial data should be read in conjunction with "Unaudited Pro Forma Consolidated Financial Information," "Selected Historical Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements of NRG Energy, Inc. and the related notes thereto included elsewhere in this report.

(Dollars in thousands)	Pro Forma Twelve Months Ended September 30, 2003
Income Statement Data:	
Operating Revenues and Equity Earnings:	
Revenues from majority-owned operations	$ 2,102,442
Equity in earnings of unconsolidated affiliates	155,838
Total operating revenues and equity earnings	2,258,280
Operating Costs and Expenses:	
Cost of majority-owned operations	1,521,185
Depreciation and amortization	168,220
General, administrative and development expenses	182,683
Write downs and losses on sales of equity method investments	209,474
Legal settlement	396,000
Restructuring and impairment charges	392,115
Total operating costs and expenses	2,869,677
Operating (Loss)/ Income	(611,397)
Other Income (Expense):	
Minority interest in (earnings)/losses of consolidated subsidiaries	(2,388)
Other income, net	(2,285)
Interest expense	(345,076)
Total other expense	(349,749)
(Loss)/ Income From Continuing Operations Before Income Taxes	(961,146)
Income Tax (Benefit)/ Expense	32,383
(Loss)/ Income From Continuing Operations	$ (993,529)

	Pro Forma At September 30, 2003
Balance Sheet Data (at period end):	
Cash and cash equivalents	$ 173,577
Restricted cash	737,644
Total assets	9,041,436
Total long-term debt, including current maturities	4,852,005
Stockholders' equity	2,403,865

Summary Other Financial Data

The following table sets forth summary other financial data for the periods ended as indicated below. The summary financial data for the fiscal year ended December 31, 2002, the nine months ended September 30, 2003 and the twelve months ended September 30, 2003 give effect to the completion of the Reorganization Events and the Refinancing Transactions, including the effectiveness of the NRG plan of reorganization and the effect of fresh-start accounting principles.

The following data should be read in conjunction with "Unaudited Pro Forma Consolidated Financial Information," "Selected Historical Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements of NRG Energy, Inc. and the related notes thereto included elsewhere in this report.

	Pro Forma		
(Dollars in thousands)	Year Ended December 31, 2002	Nine Months Ended September 30, 2003	Twelve Months Ended September 30, 2003
(Loss)/ Income From Continuing Operations	$(2,522,285)	$ (766,339)	$ (993,529)
Plus:			
Income tax (benefit)/ expense	(163,236)	44,864	32,383
Interest expense	240,495	227,117	345,076
Depreciation and amortization	151,665	127,507	168,220
Pro Forma EBITDA(1)	$(2,293,361)	$ (366,851)	$ (447,850)
Plus:			
Legal settlement	—	396,000	396,000
Restructuring and impairment charges	2,627,766	298,019	392,115
Write downs and losses on sales of equity method investments	200,472	136,717	209,474
Pro Forma Adjusted EBITDA(2)	$ 534,877	$ 463,885	$ 549,739
Ratio of Pro Forma Adjusted EBITDA to interest expense			1.6x

(1) Pro Forma EBITDA represents (loss)/income from continuing operations before interest, taxes, depreciation and amortization. We present Pro Forma EBITDA because we consider it an important supplemental measure of our performance and believe it is frequently used by securities analysts, investors and other interested parties in the evaluation of companies in our industry. Pro Forma EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our results as reported under GAAP. Some of these limitations are:

- Pro Forma EBITDA does not reflect our cash expenditures, or future requirements for capital expenditures, or contractual commitments;
- Pro Forma EBITDA does not reflect changes in, or cash requirements for, our working capital needs;
- Pro Forma EBITDA does not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments, on our debts;
- Although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and Pro Forma EBITDA does not reflect any cash requirements for such replacements; and
- Other companies in our industry may calculate Pro Forma EBITDA differently than we do, limiting its usefulness as a comparative measure.

Because of these limitations, Pro Forma EBITDA should not be considered as a measure of discretionary cash available to use to invest in the growth of our business. We compensate for these limitations by relying primarily on our GAAP results and using Pro Forma EBITDA and Pro Forma Adjusted EBITDA only supplementally. See the statements of cash flow included in our financial statements that are a part of this report.

(2) We present Pro Forma Adjusted EBITDA as a further supplemental measure of operating performance. We prepare Pro Forma Adjusted EBITDA by adjusting Pro Forma EBITDA to eliminate the impact of a number of items we do not consider indicative of future operating performance. You are encouraged to evaluate each adjustment and the reasons we consider it appropriate for supplemental analysis. As an analytical tool, Pro Forma Adjusted EBITDA is subject to all of the limitations applicable to Pro Forma EBITDA. In addition, in evaluating Pro Forma Adjusted EBITDA, you should be aware that in the future we may incur expenses similar to the adjustments in this presentation. Our presentation of Pro Forma Adjusted EBITDA should not be construed as an inference that our future results will be unaffected by unusual or non-recurring items.

Pro Forma Adjusted EBITDA is calculated by adding to Pro Forma EBITDA certain expense items and deducting from Pro Forma EBITDA certain income items that we believe are unusual and not indicative of our future operating performance. For additional information regarding these adjustments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our audited and unaudited financial statements included elsewhere in this report.

Summary Historical Consolidated Financial Data

The following table sets forth our summary historical consolidated financial data for the periods ended and at the dates indicated below. We have derived the audited historical consolidated financial data as of and for the fiscal years 2000, 2001 and 2002 from our audited financial statements included elsewhere in this report. We have derived the unaudited historical consolidated financial data for the nine-month periods ended September 30, 2002 and 2003 from our unaudited consolidated financial statements included elsewhere in this report. In the opinion of our management, our unaudited consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments necessary for a fair presentation of our financial position, results of operations and cash flows. The results of operations for the nine-month periods ended September 30, 2002 and 2003 are not necessarily indicative of the operating results to be expected for the full fiscal year.

The following summary consolidated financial information should be read in conjunction with "Selected Historical Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements of NRG Energy, Inc. and the related notes thereto included elsewhere in this report.

	Year Ended December 31,			Nine Months Ended September 30,	
	2000	2001	2002	2002	2003
(Dollars in thousands)				(Unaudited)	
Income Statement Data:					
Operating Revenues and Equity Earnings:					
Revenues from majority-owned operations	$1,669,531	$2,191,152	$ 2,088,432	$ 1,602,859	$ 1,616,869
Equity in earnings of unconsolidated affiliates	139,364	210,032	68,996	68,916	155,758
Total operating revenues and equity earnings	1,808,895	2,401,184	2,157,428	1,671,775	1,772,627
Operating Costs and Expenses:					
Cost of majority-owned operations	1,053,225	1,412,006	1,398,965	1,064,021	1,186,241
Depreciation and amortization	94,078	163,014	241,521	176,686	203,050
General, administrative and development expenses	168,945	193,249	226,528	171,855	128,010
Write downs and losses on sales of equity method investments	—	—	200,472	127,715	136,717
Legal settlement	—	—	—	—	396,000
Reorganization items	—	—	—	—	27,032
Restructuring and impairment charges	—	—	2,627,766	2,533,670	298,019
Total operating costs and expenses	1,316,248	1,768,269	4,695,252	4,073,947	2,375,069
Operating (Loss)/ Income	492,647	632,915	(2,537,824)	(2,402,172)	(602,442)
Other Income (Expense):					
Minority interest in (earnings)/losses of consolidated subsidiaries	(840)	(1,847)	(1,290)	(1,317)	(2,415)
Other income, net	5,796	19,720	4,232	14,441	7,316
Restructuring interest income	—	—	—	—	608
Interest expense	(249,677)	(387,688)	(484,570)	(289,346)	(317,984)
Total other expense	(244,721)	(369,815)	(481,628)	(276,222)	(312,475)
(Loss)/ Income From Continuing Operations Before Income Taxes	247,926	263,100	(3,019,452)	(2,678,394)	(914,917)
Income Tax (Benefit)/ Expenses	98,360	39,298	(163,236)	(150,755)	44,864
(Loss)/ Income From Continuing Operations	149,566	223,802	(2,856,216)	(2,527,639)	(959,781)
(Loss)/ Income on Discontinued Operations, net of Income Taxes	33,369	41,402	(608,066)	(595,570)	53,954
Net (Loss)/ Income	$ 182,935	$ 265,204	$(3,464,282)	$ (3,123,209)	$ (905,827)

(Dollars in thousands)	Year Ended December 31, 2000	2001	2002	Nine Months Ended September 30, 2002 (Unaudited)	2003 (Unaudited)
Other Financial Data and Ratios:					
Capital expenditures, net	$ 223,560	$ 1,322,130	$ 1,439,733	$ 1,391,019	$ 85,635
Depreciation and amortization	94,078	163,014	241,521	176,686	203,050
EBITDA(1),(3)	625,050	855,204	(2,901,427)	(2,807,932)	(339,929)
Adjusted EBITDA(2),(3)	591,681	813,802	534,877	449,023	463,885
Ratio of earnings to fixed charges(4)	1.8x	1.3x	—	—	—
Balance Sheet Data (at period end):					
Cash and cash equivalents	$ 36,816	$ 105,405	$ 381,514	$ 325,902	$ 292,644
Restricted cash	7,236	140,323	277,489	207,503	487,644
Total assets	5,978,992	12,916,260	10,892,783	11,688,413	10,174,772
Long term debt:					
Recourse corporate level debt	1,504,386	3,669,900	2,998,280	4,072,382	4,088,499
Non-recourse project level debt	1,689,954	3,648,971	5,212,778	4,125,961	3,940,299
Total long-term debt, including current maturities	3,194,340	7,318,871	8,211,058	8,198,343	8,028,798
Stockholders' equity (deficit)	1,462,088	2,237,129	(696,199)	(326,660)	(1,531,217)

(1) EBITDA represents net income before interest, taxes, depreciation and amortization. We present EBITDA because we consider it an important supplemental measure of our performance and believe it is frequently used by securities analysts, investors and other interested parties in the evaluation of companies in our industry. EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our operating results as reported under GAAP. Some of these limitations are:

- EBITDA does not reflect our cash expenditures, or future requirements for capital expenditures, or contractual commitments;
- EBITDA does not reflect changes in, or cash requirements for, our working capital needs;
- EBITDA does not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments, on our debts;
- Although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA does not reflect any cash requirements for such replacements; and
- Other companies in our industry may calculate EBITDA differently than we do, limiting its usefulness as a comparative measure.

Because of these limitations, EBITDA should not be considered as a measure of discretionary cash available to use to invest in the growth of our business. We compensate for these limitations by relying primarily on our GAAP results and using EBITDA and Adjusted EBITDA only supplementally. See the statements of cash flow included in our financial statements that are a part of this report.

(2) We present Adjusted EBITDA as a further supplemental measure of operating performance. We prepare Adjusted EBITDA by adjusting EBITDA to eliminate the impact of a number of items we do not consider indicative of future operating performance. You are encouraged to evaluate each adjustment and the reasons we consider it appropriate for supplemental analysis. As an analytical tool, Adjusted EBITDA is subject to all of the limitations applicable to EBITDA. In addition, in evaluating Adjusted EBITDA, you should be aware that in the future we may incur expenses similar to the adjustments in this presentation. Our presentation of Adjusted EBITDA should not be construed as an inference that our future results will be unaffected by unusual or non-recurring items.

Adjusted EBITDA is calculated by adding to EBITDA certain expense items and deducting from EBITDA certain income items that we believe are unusual and not indicative of our future operating performance. For additional information regarding these adjustments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our audited financial statements and unaudited financial statements included elsewhere in this report.

(3) The following table summarizes the calculation of EBITDA and Adjusted EBITDA and provides a reconciliation to net income for the periods indicated:

(Dollars in thousands)	Year Ended December 31, 2000	2001	2002	Nine Months Ended September 30, 2002	2003
Net income/(loss)	$ 182,935	$265,204	$(3,464,282)	$(3,123,209)	$(905,827)
Plus:					
Income tax (benefit)/ expense	98,360	39,298	(163,236)	(150,755)	44,864
Interest expense	249,677	387,688	484,570	289,346	317,984
Depreciation and amortization expense	94,078	163,014	241,521	176,686	203,050
EBITDA	$625,050	$855,204	$(2,901,427)	$(2,807,932)	$ (339,929)
Plus:					
(Income)/ loss on discontinued operations, net of income tax	(33,369)	(41,402)	608,066	595,570	(53,954)
Legal settlement	—	—	—	—	396,000
Reorganization items	—	—	—	—	27,032
Restructuring and impairment charges	—	—	2,627,766	2,533,670	298,019
Write downs and losses on sales of equity method investments	—	—	200,472	127,715	136,717
Adjusted EBITDA	$ 591,681	$ 813,802	$ 534,877	$ 449,023	$ 463,885

(4) The ratio of earnings to fixed charges is computed by dividing earnings by fixed charges. For this purpose, "earnings" includes pre-tax income (loss) before adjustments for minority interest in our consolidated subsidiaries and income or loss from equity investees, plus fixed charges and distributed income of equity investees, reduced by interest capitalized. "Fixed charges" include interest, whether expensed or capitalized, amortization of debt expense and the portion of rental expense that is representative of the interest factor in these rentals. Earnings were insufficient to cover fixed charges by approximately $3.1 billion, $2.7 billion and $960.0 million for the periods ended December 31, 2002, September 30, 2002 and September 30, 2003, respectively.

RISK FACTORS

Risks Related to NRG Energy, Inc.

Our actual financial results may vary significantly from the projections filed with the bankruptcy court.

In connection with the NRG plan of reorganization, we were required to prepare projected financial information to demonstrate to the bankruptcy court the feasibility of the NRG plan of reorganization and our ability to continue operations upon our emergence from bankruptcy. That financial information has not been, and will not be, updated on an ongoing basis. These projections were based on financial information available to us as of May 1, 2003. The projections were initially filed with the bankruptcy court on May 14, 2003. These projections are not included in this report nor are they incorporated by reference. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance and with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to uncertainties and to a wide variety of significant business, economic and competitive risks. Our actual results will vary from those contemplated by the projections and the variations may be material.

Our actual fresh-start reporting adjustments may vary significantly from the fresh-start reporting adjustments used to calculate the pro forma financial data that is included in this report.

Upon our emergence from bankruptcy, we will adopt fresh-start reporting. Under fresh-start reporting, our confirmed enterprise value will be allocated to our assets based on their respective fair values in conformity with the purchase method of accounting for business combinations. Any portion not attributed to specific tangible or identified intangible assets will be an indefinite-lived intangible asset referred to as “reorganization value in excess of value of identifiable assets” and reported as goodwill. Any excess of fair value of assets and liabilities over confirmed enterprise value will be allocated as a pro rata reduction of the amounts that otherwise would have been assigned to all of the assets except financial assets other than investments accounted for by the equity method, assets to be disposed of by sale, deferred tax assets, prepaid assets relating to pension or other postretirement benefit plans and any other current assets.

We have prepared unaudited pro forma consolidated financial data which give effect to fresh-start reporting adjustments, as reflected in “Unaudited Pro Forma Financial Information.” These statements have been prepared by us based on the assumptions described in the footnotes to the pro forma financial information contained in this report. However, we will obtain valuations as of the date we emerge from bankruptcy and as a result, we expect there may be adjustments in carrying values of certain assets and such adjustments may be material. To the extent actual valuations differ from those used in calculating the unaudited pro forma consolidated financial data, these differences will be reflected in our balance sheet upon emergence from bankruptcy under fresh start reporting and may affect the amount of depreciation and amortization expense we recognize in our statement of operations post-emergence.

Because our consolidated financial statements will reflect fresh-start reporting adjustments made upon our emergence from bankruptcy, financial information reflecting our future results of operations and financial condition will not be comparable to prior periods.

As a result of adopting fresh-start reporting, the book value of our long-lived assets and the related depreciation and amortization schedules, among other things, will change from that reflected in our historical consolidated financial statements. Our future results will not be comparable to the historical consolidated statement of operations data included in this report. Following our emergence from bankruptcy, you will not be able to compare certain information reflecting our results of operations and financial condition to those for periods prior to our emergence from bankruptcy without making adjustments for fresh-start reporting.

Our operations are subject to hazards customary to the power generation industry. We may not have adequate insurance to cover all of these hazards.

Our operations are subject to many hazards associated with the power generation industry which may expose us to significant liabilities for which we may not have adequate insurance coverage. Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks such as earthquake, flood, lightning, hurricane and wind, hazards, such as fire, explosion, collapse and machinery failure are inherent in our operations. These hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plants and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties. We maintain an amount of insurance protection that we consider adequate, but we cannot assure you that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. A successful claim for which we are not fully insured could hurt our financial results and materially harm our financial condition. Further, due to rapidly rising insurance costs, we cannot assure you that insurance coverage will continue to be available at all or at rates or on terms similar to those presently available to us.

Our revenues are unpredictable because many of our power generation facilities operate, wholly or partially, without long-term power purchase agreements. Further, because wholesale power prices are subject to significant volatility, the revenues that we generate are subject to significant fluctuations.

Prior to the late 1990's, substantially all revenues from independent power generation facilities were derived under long-term power purchase agreements, pursuant to which all energy and capacity was generally sold to a single party at fixed prices. Due to changes in the wholesale power markets, the percentage of facilities, including ours, with these types of long-term power purchase agreements has decreased, and it is likely that over the next several years where there is an oversupply of generation capacity, most of our facilities will operate as "merchant" facilities without long-term agreements. Without the benefit of long-term power purchase agreements, we cannot assure you that we will be able to sell any or all of the power generated by our facilities at commercially attractive rates or that our facilities will be able to operate profitably. This could lead to us closing certain of our facilities resulting in additional economic losses and liabilities.

Further, we sell all or a portion of the energy, capacity and other products from many of our facilities to wholesale power markets. The prices of energy products in those markets are influenced by many factors outside of our control, including fuel prices, transmission constraints, supply and demand, weather, economic conditions and the rules, regulations and actions of the system operators and regulatory regimes in those markets. In addition, unlike most other commodities, power can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, the wholesale power markets are subject to significant price fluctuations over relatively short periods of time and can be unpredictable.

Increasing competition in wholesale power markets may have a material adverse effect on our results of operations and cash flows, and we may require additional liquidity to remain competitive.

Our wholesale energy operations compete with other providers of electric energy in the procurement of fuel and the sale of energy and related products. In order to successfully compete, we must have the ability to aggregate fuel supplies at competitive prices from different sources and locations and must be able to efficiently utilize transportation services from third-party pipelines, railways and other fuel transporters and transmission services from electric utilities. We also compete against other energy merchants on the basis of our relative skills, financial position and access to credit sources. Energy customers, wholesale energy suppliers and transporters often seek financial guarantees and other assurances that their energy contracts will be satisfied. In addition, our merchant asset business is constrained by our liquidity, our access to credit and the reduction in market liquidity. Other companies with which we compete may not have similar constraints.

A substantial portion of our anticipated earnings in 2004 are expected to be derived from our California generation assets, and we cannot assure you as to the collectibility of all amounts owed to our California affiliates.

In March 2001, certain affiliates of West Coast Power entered into a contract with the California Department of Water Resources, or the "CDWR," pursuant to which the affiliates agreed to sell up to 2,300 MW from January 1, 2002 through December 31, 2004, any of which may be resold by the CDWR to utilities such as Southern California Edison Company, or "SCE," PG&E and San Diego Gas and Electric Company, or "SDG&E." The ability of the CDWR to make future payments is subject to the CDWR having a continued source of funding, whether from legislative or other emergency appropriations, from a bond issuance or from amounts collected from SCE, PG&E and SDG&E for deliveries to their customers. As a result of the present situation in California, we are exposed to a risk of delayed payments and/or non-payment regardless of whether the sales are made directly to PG&E, SCE or SDG&E or to the California ISO or the CDWR.

Construction, expansion, refurbishment and operation of power generation facilities involve significant risks that cannot always be covered by insurance or contractual protections and could have a material adverse effect on our revenues and results of operations.

We are exposed to risks relating to the breakdown or failure of equipment or processes, shortages of equipment and supply, material and labor and operating performance below expected levels of output or efficiency. A significant portion of our facilities was constructed many years ago. Older equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to keep it operating at optimum efficiency. This equipment is also likely to require periodic upgrading and improvement. Any unexpected failure, including failure caused by breakdown, forced outage or any unanticipated capital expenditure, could result in reduced profitability. In addition, if we make any "major modifications" to our power generation facilities, as defined under the new source review provisions of the Federal Clean Air Act, we would be required to install "best available control technology" or to achieve the "lowest achievable emissions rate." Any such modifications would likely result in substantial additional capital expenditures. In general, environmental laws, particularly with respect to air emissions, are becoming more stringent, which may require us to install expensive plant upgrades and/or restrict our operations to meet more stringent standards.

We cannot always predict the level of capital expenditures that will be required due to changing environmental and safety laws and regulations, deteriorating facility conditions and unexpected events (such as natural disasters or terrorist attacks). The unexpected requirement of large capital expenditures could have a material adverse effect on our financial performance and condition. Further, the construction, expansion, modification and refurbishment of power generation, thermal energy production and transmission and resource recovery facilities involve many risks, including:

- dispatch at our facilities;
- supply interruptions;
- work stoppages;
- labor disputes;
- social unrest;
- weather interferences;
- unforeseen engineering, environmental and geological problems; and
- unanticipated cost overruns.

The ongoing operation of our facilities involves all of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes, performance below expected levels of output or efficiency and the inability to transport our product to our customers in an efficient manner due to a lack in transmission capacity. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance, warranties or performance guarantees may not be adequate to cover lost revenues, increased expenses or liquidated damages payments should we experience equipment breakdown or non-performance of contractors. Any of these risks could cause us to operate below expected capacity levels, which in turn could result in lost revenues, increased expenses, higher maintenance costs and penalties.

We are exposed to the risk of fuel and fuel transportation cost increases and volatility and interruption in fuel supply because our facilities generally do not have long-term natural gas, coal and liquid fuel supply agreements.

Most of our domestic natural gas-, coal- and oil-fired power generation facilities purchase their fuel requirements under short-term contracts or on the spot market. Although we attempt to purchase fuel based on our known fuel requirements, we still face the risks of supply interruptions and fuel price volatility as fuel deliveries may not exactly match energy sales due in part to our need to prepurchase inventories for reliability and dispatch requirements. The price we can obtain for the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel costs. This may have a material adverse effect on our financial performance. Moreover, changes in market prices for natural gas, coal and oil may result from the following:

- weather conditions;
- seasonality;
- demand for energy commodities and general economic conditions;
- forced or unscheduled plant outages;
- disruption of electricity, gas or coal transmission or transportation, infrastructure or other constraints or inefficiencies;
- additional generating capacity;
- availability of competitively priced alternative energy sources;
- availability and levels of storage and inventory for fuel stocks;
- natural gas, crude oil and refined products and coal production levels;
- the creditworthiness or bankruptcy or other financial distress of market participants;
- changes in market liquidity;
- natural disasters, wars, embargoes, acts of terrorism and other catastrophic events; and
- federal, state and foreign governmental regulation and legislation.

The volatility of fuel prices could adversely affect our financial results and operations.

Future decreases in gas prices in certain markets may adversely impact our financial performance.

Certain of our facilities, particularly our coal generation assets, are currently benefiting from higher electricity prices in their respective markets as a result of high gas prices compared to historical levels. A decrease in gas prices may lead to a corresponding decrease in electricity prices in these markets, which could adversely impact our financial performance.

We often rely on single suppliers and at times we rely on single customers at our facilities, exposing us to significant financial risks if either should fail to perform their obligations.

We often rely on a single supplier for the provision of fuel, water and other services required for operation of a facility, and at times, we rely on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that provide the support for any project debt used to finance the facility. During 2002, we derived approximately 22.1% of our revenues from majority-owned operations from one customer: the New York Independent System Operator, or “NYISO.” During 2001, we derived approximately 51.5% of our revenues from majority-owned operations from two customers: NYISO (33.9%) and Connecticut Light and Power Company, or “CL&P” (17.6%). The failure of any supplier or customer to fulfill its contractual obligations to the facility could have a material adverse effect on such facility’s financial results. Consequently, the financial performance of any such facility is dependent on the credit quality and continued performance by suppliers and customers of their obligations under these long-term agreements.

We may not have sufficient liquidity to effectively hedge market risks.

We are exposed to market risks through our power marketing business, which involves the sale of energy, capacity and related products and procurement of fuel, transmission rights and emission allowances. These market risks include, among other risks, volatility arising from the timing differences associated with buying fuel, converting fuel into energy and delivering the energy to a buyer. We seek to manage this volatility by entering into forward and other contracts which hedge the amount of exposure for our net transactions. As such, the effectiveness of our hedging strategy may be dependent on the amount of collateral available to enter into these hedging contracts and liquidity requirements may be greater than we anticipate or are able to meet. Without a sufficient amount of working capital to post as collateral in support of performance guarantees or as cash margin, we may not be able to effectively manage this price volatility. Factors which could lead to an increase in our required collateral include adverse changes in our industry, additional credit rating downgrades or the secured nature of our New Credit Facility. Under certain unfavorable commodity price scenarios, it is possible that we could experience inadequate liquidity as a result of the posting of additional collateral.

Further, if our facilities experience unplanned outages, we may be required to procure replacement power in the open market to minimize our exposure to liquidated damages. Without adequate liquidity to post margin and collateral requirements, we may be exposed to significant losses and may miss significant opportunities, and we may have increased exposure to the volatility of spot markets.

Our risk management activities may increase the volatility in our quarterly financial results.

We engage in commodity-related marketing and price-risk management activities in order to hedge our exposure to market risk with respect to electricity sales from our generation assets, emission allowances and fuel utilized by those assets. We generally attempt to balance our fixed-price physical and financial purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative contracts. These derivatives are accounted for in accordance with Financial Accounting Standards No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities,” or “FAS No. 149,” accounting pronouncement. FAS No. 149 requires us to record all derivatives on the balance sheet at fair value. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as accounting 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 (OCI) until the hedged transactions occur and are recognized in earnings. As a result, most derivative contracts are mark-to-market and changes in their fair value, brought upon by fluctuations in the underlying commodity prices, flow through the statement of operations. As a result, we are unable to predict the impact that our risk management decisions may have on our quarterly operating results or financial position.

Our results are subject to quarterly and seasonal fluctuations.

Our quarterly operating results have fluctuated in the past and may continue to do so in the future as a result of a number of factors, including:

- seasonal variations in demand and corresponding energy and fuel prices; and

- variations in levels of production.

Additionally, because we receive the majority of capacity payments under some of our power sales agreements during the months of May through October, our revenues and results of operations are subject to seasonal fluctuations.

Large energy blackouts have the potential to reduce our revenue collection, increase our costs and result in increased federal and state regulatory requirements.

On August 14, 2003, the northeastern United States and parts of Canada suffered a massive blackout allegedly stemming from transmission problems originating in Ohio. The Department of Energy, in conjunction with its Canadian counterpart, is actively investigating the cause of the outage. Upon completion, there are likely to be changes to NERC reliability criteria and standards that may impact the operation of power plants owned by us. Other entities such as the New York Public Service Commission are also conducting investigations. Upon completion of these investigations, there may be regulatory changes and we cannot predict the impact of such changes. Moreover, the business of selling power is fundamentally dependent on the integrity of the electricity transmission system. Large energy blackouts, such as the blackout described above, can occur as a result of failures in the electricity transmission system. Such blackouts have the potential to reduce our revenue collection, increase our costs and engender enhanced federal and state regulatory requirements.

Because we own less than a majority of some of our project investments, we cannot exercise complete control over their operations.

We have limited control over the operation of some project investments and joint ventures because our investments are in projects where we beneficially own less than a majority of the ownership interests. We seek to exert a degree of influence with respect to the management and operation of projects in which we own less than a majority of the ownership interests by negotiating to obtain positions on management committees or to receive certain limited governance rights such as rights to veto significant actions. However, we may not always succeed in such negotiations. We may be dependent on our co-venturers to operate such projects. Our co-venturers may not have the level of experience, technical expertise, human resources management and other attributes necessary to operate these projects. The approval of co-venturers also may be required for us to receive distributions of funds from projects or to transfer our interest in projects.

Our access to the capital markets may be limited.

We may require additional capital from outside sources from time to time. Our ability to arrange financing, either at the corporate level or on a non-recourse project-level basis, and the costs of such capital are dependent on numerous factors, including:

- general economic and capital market conditions;

- credit availability from banks and other financial institutions;

- investor confidence in us, our partners and the regional wholesale power markets;

- our financial performance and the financial performance of our subsidiaries;

- our levels of indebtedness;

- maintenance of acceptable credit ratings;

- the success of current projects;

- provisions of tax and securities laws that may impact raising capital; and

- our ability to acquire any necessary regulatory approvals.

We may not be successful in obtaining additional capital for these or other reasons. The failure to obtain additional capital from time to time may have a material adverse effect on our business and operations.

Our business is subject to substantial governmental regulation and permitting requirements and may be adversely affected by liability under, or any future inability to comply with, existing or future regulations or requirements.

Our business is subject to extensive foreign, federal, state and local energy, environmental and other laws and regulations. We generally are required to obtain and comply with a wide variety of licenses, permits and other approvals in order to construct, operate or modify our facilities. We may incur significant additional costs because of our need to comply with these requirements. If we fail to comply with these requirements, we could be subject to civil or criminal liability and the imposition of liens or fines. We could also be required to shut down any facilities that do not comply with these requirements. In addition, we are at risk for liability for past, current or future contamination at our former and existing facilities or with respect to off-site waste disposal sites that we have used in our operations. Existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to us or our facilities in a manner that may have a detrimental effect on our business. Furthermore, with the continuing trend toward stricter standards, greater regulation and more extensive permitting requirements, we expect our environmental expenditures to be substantial in the future. For more information, see “Business —Environmental Matters.”

Our operations are potentially subject to the provisions of various energy laws and regulations, including the Public Utility Holding Company Act of 1935, or “PUHCA,” the Federal Power Act, or “FPA,” and state and local utility laws and regulations.

Under the FPA, FERC regulates our wholesale sales of electric power (other than sales by our Qualifying Facilities, which are exempt from FERC rate regulation). The ability to sell energy at market-based rates is predicated on the absence of market power in either generation or transmission. The market power analysis includes not only generation and transmission owned by a particular applicant but also assets owned by affiliated companies. FERC has found that we do not possess market power in either generation or transmission outside of the Xcel Energy franchise territories. Once we terminate our Xcel Energy relationship, we can request FERC to find that we do not possess market power with respect to Xcel Energy franchise territories and request FERC to remove associated restrictions on our ability to make market-based rate sales in such regions. Holders of market-based rate authority must comply with obligations imposed by FERC and with certain FERC filing requirements such as the requirement to file quarterly reports detailing wholesale sales. Although a number of our direct and indirect subsidiaries have obtained market-based rate authority from FERC, these authorizations could be revoked if we fail in the future to satisfy the applicable criteria, if FERC modifies the criteria, or if FERC eliminates or further restricts the ability of wholesale sellers to make sales at market-based rates. On November 17, 2003, FERC issued an order conditioning all market-based rate sales on behavioral rules intended to prevent market manipulation and other market abuses. All market-based sales will be conditioned on compliance with these behavioral rules and violations of such conditions could result in a seller being subject to refunds, revocation of market-based rate authority and other unspecified remedies for violating the conditions. At this time it is not clear what impact this proposal may have on us.

In addition, under PUHCA, registered holding companies and their subsidiaries (i.e., companies with 10% or more of their voting securities held by registered holding companies) are subject to extensive regulation by the SEC. We are currently a subsidiary of a registered holding company, Xcel Energy. Upon our emergence from bankruptcy, we will cease to be a subsidiary of Xcel Energy and will not be subject to regulation under PUHCA as a registered holding company or as a subsidiary of such a holding company, as long as we do not become a subsidiary of another registered holding company and the projects in which we have an interest (1) qualify as Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978, or “PURPA,” (2) obtain and maintain exempt wholesale generator, or “EWG,” status under Section 32 of PUHCA, (3) obtain and maintain foreign utility company, or “FUCO,” status under Section 33 of PUHCA, or (4) are subject to another exemption or waiver. If our projects were to cease to be exempt and we were to become subject to SEC regulation under PUHCA, it would be difficult for us to comply with PUHCA absent a substantial restructuring.

While we will not be a subsidiary of a registered holding company after our emergence from bankruptcy, we will become an affiliate (as defined by PUHCA, a company with between 5-10% of its voting securities held by a registered holding company) of FirstEnergy Corp., or “FirstEnergy,” a registered holding company, if FERC approves FirstEnergy’s application to acquire 6.5% of our outstanding common stock upon emergence from bankruptcy as part of a settlement. Although becoming an affiliate of FirstEnergy would subject us to certain limitations on our transactions with FirstEnergy and other restrictions, these restrictions are less substantial than those applicable to us when we were a subsidiary of Xcel Energy.

Energy legislation currently pending before Congress, or the “Energy Bill,” would repeal PUHCA one year after passage and create new rules for holding companies. At this time, the Energy Bill has stalled in Congress and it is unclear whether it will be passed into law. In addition, if the Energy Bill is passed, it is unclear what impact, if any, the new rules for holding companies would have on us.

Our business faces regulatory risks related to the market rules and regulations imposed by transmission providers, ISOs and RTOs particularly with respect to our Connecticut generating assets.

We face regulatory risk imposed by the various transmission providers, ISOs and RTOs and their corresponding market rules. Transmission providers, ISOs and RTOs have FERC-approved tariffs that govern access to their transmission system. These tariffs may contain provisions that limit access to the transmission grid or allocate scarce transmission capacity in a particular manner.

We presently operate in the following ISO markets: California (through the West Coast Power joint venture and individually), New England, New York and PJM. The chief regulatory risk is the market mitigation policies imposed by the individual ISOs on our generation assets, particularly in Connecticut where an interim market solution known as “peaking unit safe harbor” bidding, or “PUSH” bidding, remains in effect until a locational installed capacity market can be implemented. See “Business—Power Generation— Eastern Region” elsewhere in this report for more information.

We serve approximately 45% percent of the standard offer service, or “SOS,” for CL&P. The SOS obligation ends on December 31, 2003. Under the SOS, the issue of who is responsible for congestion costs and marginal losses after the introduction of standard market design on March 1, 2003 became a contested issue. We are now litigating the issues of who is responsible for these costs before the FERC. The total amount of congestion costs and losses from March 1, 2003 through December 31, 2003 is estimated to be approximately $180 million to $190 million, with our share being approximately $81 million to $86 million. CL&P has been withholding the moneys from us for these costs pending a final determination by FERC. A settlement judge has been appointed to resolve the case and settlement discussions have occurred, though appear to have reached an impasse. At this time it is not known whether the case can be settled. If the case is not settled it is anticipated that a final decision by FERC would not occur until 2004.

Our success will depend on our ability to hire and retain key employees and may be adversely affected by vacancies.

Prior to our bankruptcy filing, we were managed primarily by senior executives who have subsequently left NRG Energy. During the fourth quarter of 2002, our officers determined that there were certain deficiencies or “reportable conditions” in the internal controls relating to financial reporting at NRG caused by our pending financial restructuring, including vacancies in our senior management positions and a diversion of our financial and management resources to restructuring efforts. These circumstances detracted from our ability through internal controls to timely monitor and accurately assess the impact of certain transactions, as would be expected in an effective financial reporting control environment. Our future success and the successful implementation of our comprehensive restructuring will be highly dependent upon our new President and Chief Executive Officer, David W. Crane, as well as other members of senior management. Although Mr. Crane and several other members of senior management are subject to employment agreements, such employment agreements may be terminated and the loss of the services of any such individuals or other key personnel could have a material adverse effect upon the implementation of our comprehensive restructuring plan and on our success in general.

In August 2002, we engaged Kroll Zolfo Cooper and hired certain restructuring professionals affiliated with Kroll Zolfo Cooper to serve as members of our senior management team to, among other things, provide restructuring and other financial services during the pendency of the bankruptcy case. Following the effective date of the NRG plan of reorganization, there will be a transition period after which Kroll Zolfo Cooper will no longer be retained by us and some of the services presently provided by these professionals will be performed by current employees or employees that we must hire. There can be no assurance that we will be able to hire such employees in a timely manner or that this transition will not result in an interruption of these services. Such an interruption could harm our ability to continue to develop and manage our business and implement our comprehensive restructuring plan. Further, there can be no guarantee that our new management team will be able to implement successful business strategies going forward.

We have been required to restate certain of our prior financial statements.

In 1997, 1998, 1999 and 2002, we amended our annual reports on Form 10-K to provide required financial information for significant subsidiaries for which financial information was unavailable at the time we filed our respective Form 10-K's. In addition, on or about December 8, 2003, we will amend our quarterly report on Form 10-Q to reflect a reclassification of certain expenses.

We will be subject to claims made after the date that we filed for bankruptcy and other claims that are not discharged in the bankruptcy proceeding, which could have a material adverse effect on our results of operations and profitability.

The nature of our business subjects us to litigation in the ordinary course of business. In addition, we are from time to time involved in other legal proceedings. Although all claims made against us prior to the date of the bankruptcy filing, except as described in the immediately following paragraph, will be satisfied and discharged in accordance with the terms of the NRG plan of reorganization or in connection with settlement agreements that are approved by the bankruptcy court prior to our emergence from bankruptcy, any remaining or future claims may have a material adverse effect on our results of operations and profitability. In addition, claims arising after the date of our bankruptcy filing will not be discharged in the bankruptcy proceeding. See the "Business — Legal Proceedings" section of this report for a description of the significant legal proceedings and investigations in which we are presently involved.

Claims made against us prior to the date of the bankruptcy filing might not be discharged if the claimant had no notice of the bankruptcy filing. In addition, in other bankruptcy cases, states have challenged whether their claims could be discharged in a federal bankruptcy proceeding if they never made an appearance in the case. This issue has not been finally settled by the U.S. Supreme Court.

In addition, our West Coast Power subsidiaries are named in a class action suit alleging, among other things, the manipulation of gas price indexes by reporting false and fraudulent trades. NRG has not been named in this litigation. Dynegy, Inc., or "Dynegy," has agreed with us that it will indemnify and hold harmless all of the named defendants in such lawsuit, as well as NRG. In the event Dynegy is unable or unwilling to satisfy its indemnification obligations, we or our West Coast Power subsidiaries could sustain substantial monetary penalties, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Under the NRG plan of reorganization, we have established disputed claim reserves, which we will utilize to make distributions to holders of disputed claims in our bankruptcy as and when their claims are resolved. If these reserves prove inadequate, we will be required to finance required distributions from other resources, and doing so could have an adverse impact on our financial condition. In particular, the State of California has a disputed claim against us in an amount capped at $1.35 billion. We have made no reserves for this claim because we believe it is without merit; however, if the State of California prevails, then payment of the distributions to which the State of California is entitled under the NRG plan of reorganization could have a significant impact on our financial condition.

We cannot be certain that the bankruptcy proceeding will not adversely affect our operations going forward.

Although we have emerged from bankruptcy, we cannot assure you that the bankruptcy proceeding will not adversely affect our operations going forward. Our filing for bankruptcy protection may adversely affect our ability to negotiate favorable terms from suppliers, landlords and others and to attract and retain customers. The failure to obtain such favorable terms and retain customers could adversely affect our financial performance.

Certain of our prepetition creditors will receive NRG common stock pursuant to the NRG plan of reorganization and have the right to select our board members and influence certain aspects of our business operations.

Under the NRG plan of reorganization, upon our emergence from bankruptcy, holders of certain claims will receive distributions of shares of NRG common stock. MatlinPatterson manages funds which, based on the most recent information made available to us, collectively are expected to receive at least 20% of our outstanding common stock upon emergence from bankruptcy. MatlinPatterson could acquire additional claims or shares, or it could divest claims or shares in the future. Our prepetition noteholders and lenders are expected to collectively receive in excess of 80% of our outstanding common stock. Also, as part of a settlement agreement resolving certain contractual disputes, FirstEnergy will receive an approximately 6.5% interest in NRG if FERC approves FirstEnergy's application to acquire the shares. Other than MatlinPatterson and FirstEnergy, however, we are not aware of any other entity that will own or control 5% or more of our outstanding common stock as a result of our plan of reorganization.

If any holders of a significant number of the shares of NRG common stock were to act as a group, such holders could be in a position to control the outcome of actions requiring stockholder approval, such as an amendment to our certificate of incorporation, the authorization of additional shares of capital stock, and any merger, consolidation, sale of all or substantially all of the assets of NRG, and could prevent or cause a change of control of NRG. Moreover, certain of our prepetition creditors, including MatlinPatterson and lenders under our prepetition credit facility, will have rights to designate ten members of our initial 11-member board of directors upon our emergence from bankruptcy. Other than David W. Crane, our new President and Chief Executive Officer, all of our initial board members will be newly appointed members upon our emergence from bankruptcy. See "The Bankruptcy Case" section of this report for a description of such designation right.

Acts of terrorism could have a material adverse effect on our financial condition, results of operations and cash flows.

Our generation facilities and the facilities of third parties on which they rely may be targets of terrorist activities, as well as events occurring in response to or in connection with them, that could cause environmental repercussions and/or result in full or partial disruption of their ability to generate, transmit, transport or distribute electricity or natural gas. Strategic targets, such as energy-related facilities, may be at greater risk of future terrorist activities than other domestic targets. Any such environmental repercussions or disruption could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Our liquidity position could be materially adversely affected in the event of a decline in the market price of Xcel Energy's common stock.

A principal component of the NRG plan of reorganization is a settlement with Xcel Energy in which Xcel Energy agreed to make a contribution consisting of cash (and, under certain circumstances, its stock) in the aggregate amount of up to $640 million to be paid in three separate installments following the effective date of the NRG plan of reorganization. The Xcel Energy settlement agreement resolves any and all claims existing between Xcel Energy and us and/or our creditors. In exchange for the Xcel Energy contribution, Xcel Energy will receive a complete release of claims from NRG and its creditors. Subject to the terms and conditions of the settlement agreement, Xcel Energy may satisfy part of its contribution obligations with the payment of up to $200 million in Xcel Energy common stock. In the event of a subsequent decline in the market price of Xcel Energy's common stock, our liquidity and financial flexibility could be materially adversely affected. For more information on the Xcel Energy settlement, see "The Bankruptcy Case."

Our international investments may face uncertainties.

We have investments in power projects in Australia, the United Kingdom, Germany, South America and Taiwan in operation. International investments are subject to risks and uncertainties relating to the political, social and economic structures of the countries in which we invest. Risks specifically related to investments in non-United States projects may include:

- fluctuations in currency valuation;
- currency inconvertibility;
- expropriation and confiscatory taxation;
- increased regulation; and
- approval requirements and governmental policies limiting returns to foreign investors.

Certain of our subsidiaries remain in chapter 11, and we may deem it necessary to put additional subsidiaries through chapter 11.

The following subsidiaries are not covered by either of the two plans of reorganization that were confirmed in November, and remain in chapter 11: NRG McClain LLC, NRG Nelson Turbines LLC and LSP-Nelson Energy LLC. In addition, we anticipate that it may be necessary or advisable to put one or more of our other subsidiaries through chapter 11 as part of our overall restructuring effort. The existence of these ongoing chapter 11 proceedings may adversely affect the way we are perceived by investors, financial markets, customers, suppliers and regulatory authorities, which could adversely affect our operations and financial performance.

Our chapter 11 reorganization has exposed certain of our project subsidiaries to the exercise of rights and remedies by project lenders or shareholders.

At a number of our project subsidiaries, our pre-bankruptcy financial distress, the chapter 11 reorganization or the loss of Xcel Energy as a controlling shareholder could constitute a default under certain project loan agreements or shareholders agreements. Absent a waiver of these defaults from the applicable lenders, we may not be able to prevent the acceleration of the project debt and the exercise of remedies against the project subsidiaries. Likewise, absent a waiver from the affected shareholders, those shareholders may be able to enforce buy-out rights or other remedies against our project subsidiaries. As of the date of this report, we have not been able to obtain waivers or make other arrangements with certain of these project lenders and shareholders, and there is no assurance that we will be able to in the future. If we are unable to obtain waivers or make other arrangements, our project subsidiaries may be adversely affected, which may cause adverse effects to us as a whole.

FORWARD-LOOKING STATEMENTS

This current report includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, as amended, or the "Exchange Act." The words "believes," "anticipates," "plans," "expects," "intends," "estimates" and similar expressions are intended to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statement. These factors, risks and uncertainties include, but are not limited to, the following:

- Uncertainties affecting the financial projections prepared in connection with the bankruptcy;
- Lack of comparable financial data due to adoption of fresh-start reporting and the possibility of significant variations between our actual and pro forma fresh-start reporting adjustments;
- Hazards customary to the power production industry and the possibility that we may not have adequate insurance to cover losses as a result of such hazards;
- Our inability to enter into intermediate and long-term contracts to sell power and procure fuel on terms and prices acceptable to us;
- Increasing competition in wholesale power markets that may require additional liquidity for us to remain competitive;
- The present condition of the California energy market which may impact the collectibility of certain amounts owed to our California affiliates by the California Department of Water Resources;
- Risks associated with timely completion of capital improvement and re-powering projects, including supply interruptions, work stoppages, labor disputes, social unrest, weather interferences, unforeseen engineering, environmental or geological problems and unanticipated cost overruns;
- Volatility of energy and fuel prices and the possibility that we will not have sufficient working capital and collateral to post performance guarantees or margin calls to mitigate such risks or manage such volatility;
- Failure of customers and suppliers to perform under agreements, including failure to deliver procured commodities and services and failure to remit payment as required and directed, especially in instances where we are relying on single suppliers or single customers at a particular facility;
- Changes in the wholesale power market, including reduced liquidity, which may limit opportunities to capitalize on short-term price volatility;
- Large energy blackouts, such as the blackout that impacted parts of the northeastern United States and Canada during the middle of August 2003, which have the potential to reduce our revenue collection, increase our costs and engender enhanced federal and state regulatory requirements;
- Limitations on our ability to control projects in which we have less than a majority interest;
- The condition of the capital markets generally, which will be affected by interest rates, foreign currency fluctuations and general economic conditions;
- Changes in government regulation, including but not limited to the pending changes of market rules, market structures and design, rates, tariffs, environmental regulations and regulatory compliance requirements imposed by the Federal Energy Regulatory Commission, or “FERC,” state commissions, other state regulatory agencies, the Environmental Protection Agency, or “EPA,” the National Electric Reliability Council, or “NERC,” transmission providers, Regional Transmission Organizations, or “RTOs,” Independent System Operators, or “ISOs,” or other regulatory or industry bodies;
- Price mitigation strategies employed by ISOs that result in a failure to adequately compensate our generation units for all of their costs;
- Employee workforce factors including the hiring and retention of key executives, including our new President and Chief Executive Officer and, when hired, our Chief Financial Officer, collective bargaining agreements with union employees or work stoppages;

- Cost and other effects of legal and administrative proceedings, settlements, investigations and claims, including claims which are not discharged in the bankruptcy proceedings and claims arising after the date of our bankruptcy filing;

- The impact of the bankruptcy proceedings on our operations going forward, including the impact on our ability to negotiate favorable terms with suppliers, customers, landlords and others;

- The right of certain of our prepetition creditors who will receive NRG common stock upon our emergence from bankruptcy to select our board members and influence certain aspects of our business operations;

- Acts of terrorism both in the United States and internationally;

- Trade, monetary, fiscal, taxation and environmental policies of governments, agencies and similar organizations in geographic areas where we have a financial interest;

- Material developments with respect to and ultimate outcomes of legal proceedings and investigations relating to our past and present activities;

- The fact that certain of our subsidiaries will remain in bankruptcy after our emergence, and the potential that additional subsidiaries may file for bankruptcy in the future;

- The exposure of certain of our project subsidiaries to exercise the rights and remedies by respective project lenders or shareholders as a result of our chapter 11 bankruptcy reorganization;

- Factors affecting power generation operations such as unusual weather conditions; catastrophic weather-related or other damage to facilities; unscheduled generation outages, maintenance or repairs; unanticipated changes to fossil fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;

- Our ability to borrow additional funds and access capital markets;

- Our substantial indebtedness and the possibility that we may incur additional indebtedness going forward;

- Significant operating and financial restrictions placed on us by the documents governing our indebtedness;

- Our ability to generate sufficient cash flow to make interest payments on our indebtedness;

- Other business or investment considerations that may be disclosed from time to time in our SEC filings or in other publicly disseminated written documents.

These forward-looking statements speak only as of the date of this report. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors that could cause our actual results to differ materially from those contemplated in any forward-looking statements included in this report should not be construed as exhaustive. You should also read, among other things, the risks and uncertainties described in the section titled “Risk Factors.” We qualify all our forward-looking statements by these cautionary statements.

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL INFORMATION

The following unaudited pro forma consolidated financial data have been prepared by applying adjustments to our consolidated financial statements included elsewhere in this report. Pursuant to American Institute of Certified Public Accountants, or "AICPA," Statement of Position 90-7 "Financial Reporting by Entities in Reorganization under the bankruptcy code," or "SOP 90-7," the accounting for the effects of the reorganization will occur once a plan of reorganization is confirmed by the bankruptcy court and there are no remaining contingencies material to completing the implementation of the plan. The following unaudited pro forma consolidated financial information at September 30, 2003 and for the year ended December 31, 2002 and the nine months ended September 30, 2003 gives effect to the Reorganization Events and the Refinancing Transactions, including the effectiveness of the NRG plan of reorganization as if the same had occurred on September 30, 2003 (in the case of balance sheet data) and as of the beginning of each of the periods presented (in the case of the statement of operations data). The pro forma financial information should be read in conjunction with our consolidated financial statements, the notes thereto and other financial information contained in this report, including the "Management's Discussion and Analysis of Financial Condition and Results of Operations." The unaudited pro forma consolidated financial data do not purport to represent what our results of operations or financial condition would actually have been if the Reorganization Events and the Refinancing Transactions had occurred on the dates indicated, nor are they indicative of results for any future periods. The fresh-start reporting principles pursuant to SOP 90-7 provide, among other things, for us to determine the value to be assigned to the assets of reorganized NRG as of the confirmation date, assuming no significant contingencies precedent to emergence. We will adopt fresh-start reporting as a result of the NRG plan of reorganization. The NRG plan of reorganization was approved by the bankruptcy court on November 24, 2003 and will become effective upon the satisfaction of certain conditions. The Northeast/ South Central Plan was approved on November 25, 2003 and will become effective upon the satisfaction of certain conditions, including the consummation of the Refinancing Transactions and the satisfaction of certain other conditions. For more information on the NRG and the Northeast/ South Central plans of reorganization, see "The Bankruptcy Case."

Under fresh-start reporting, our reorganization value will be allocated to our assets based on their respective fair values in conformity with the purchase method of accounting for business combinations; any portion not attributed to specific tangible or identified intangible assets will be treated as an indefinite-lived intangible asset referred to as "reorganization value in excess of value of identifiable assets" and reported as goodwill. Any excess of fair value of assets and liabilities over confirmed enterprise value will be allocated as a pro rata reduction of the amounts that otherwise would have been assigned to all of the assets except financial assets other than investments accounted for by the equity method, assets to be disposed of by sale, deferred tax assets, prepaid assets relating to pension or other postretirement benefit plans and any other current assets. The valuations required to determine the fair value of our assets used herein reflect the preliminary results of the valuation procedures we have performed. A valuation specialist is currently reviewing these valuations with us and, accordingly, the adjustments reflected in the pro forma financial information below are preliminary and subject to further revisions and adjustments, pending an update based on the actual amounts and applicable economic conditions as of the effective date of fresh start reporting. Our actual fresh-start reporting adjustments may vary significantly from the fresh-start reporting adjustments used to calculate the pro forma financial information that is set forth below, including the ongoing amounts of depreciation and amortization expense.

NRG ENERGY, INC. AND SUBSIDIARIES

UNAUDITED PRO FORMA CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2002			
		Pro Forma Adjustments		
	Historical	Reorganization Events	Refinancing Transactions	Pro Forma(1)
	(Dollars in thousands)			
Income Statement Data:				
Operating Revenues and Equity Earnings:				
Revenues from majority-owned operations	$ 2,088,432	$ —	$ —	$ 2,088,432
Equity in earnings of unconsolidated affiliates	68,996	—	—	68,996
Total operating revenues and equity earnings	$ 2,157,428	$ —	$ —	$ 2,157,428
Operating Costs and Expenses:				
Cost of majority-owned operations	1,398,965	—	—	1,398,965
Depreciation and amortization	241,521	(89,856)(3)	—	151,665
General, administrative and development expenses	226,528	—	—	226,528
Write downs and losses on sales of equity method investments	200,472	—	—	200,472
Restructuring and impairment charges	2,627,766	—	—	2,627,766
Total operating costs and expenses	$ 4,695,252	$ (89,856)	$ —	$ 4,605,396
Operating (Loss)/ Income	$(2,537,824)	$ 89,856	$ —	$(2,447,968)
Other Income (Expense):				
Minority interest in (earnings)/losses of consolidated subsidiaries	(1,290)	—	—	(1,290)
Other income, net	4,232	—	—	4,232
Interest expense	(484,570)	406,925(5)	(162,850)(2)	(240,495)
Total other expense	$ (481,628)	$406,925	$(162,850)	$ (237,553)
(Loss)/ Income From Continuing Operations Before Income Taxes	(3,019,452)	496,781	(162,850)	(2,685,521)
Income Tax (Benefit)/Expense	(163,236)	—	—	(163,236)
(Loss)/Income From Continuing Operations	$(2,856,216)	$496,781	$(162,850)	$(2,522,285)

NRG ENERGY, INC. AND SUBSIDIARIES

UNAUDITED PRO FORMA CONSOLIDATED STATEMENTS OF OPERATIONS

	Nine Months Ended September 30, 2003			
		Pro Forma Adjustments		
	Historical	Reorganization Events	Refinancing Transactions	Pro Forma (1)
	(Dollars in thousands)			
Income Statement Data:				
Operating Revenues and Equity Earnings:				
Revenues from majority-owned operations	$1,616,869	$ —	$ —	$1,616,869
Equity in earnings of unconsolidated affiliates	155,758	—	—	155,758
Total operating revenues and equity earnings	$1,772,627	$ —	$ —	$1,772,627
Operating Costs and Expenses:				
Cost of majority-owned operations	1,186,241	—	—	1,186,241
Depreciation and amortization	203,050	(75,543)(3)	—	127,507
General, administrative and development expenses	128,010	—	—	128,010
Write downs and losses on sales of equity method investments	136,717	—	—	136,717
Legal settlement	396,000	—	—	396,000
Reorganization items	27,032	(27,032)(4)	—	—
Restructuring and impairment charges	298,019	—	—	298,019
Total operating costs and expenses	$2,375,069	$(102,575)	$ —	$2,272,494
Operating (Loss)/ Income	$ (602,442)	$ 102,575	$ —	$ (499,867)
Other Income (Expense):				
Minority interest in (earnings)/losses of consolidated subsidiaries	(2,415)	—	—	(2,415)
Other income, net	7,924	—	—	7,924
Interest expense	(317,984)	213,005(5)	(122,138)(2)	(227,117)
Total other expense	$ (312,475)	$ 213,005	$(122,138)	$ (221,608)
(Loss)/ Income From Continuing Operations Before Income Taxes	(914,917)	315,580	(122,138)	(721,475)
Income Tax (Benefit)/Expense	44,864	—	—	44,864
(Loss)/Income From Continuing Operations	$ (959,781)	$ 315,580	$(122,138)	$ (766,339)

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED PRO FORMA CONSOLIDATED STATEMENTS OF OPERATIONS

(1) The unaudited pro forma consolidated statements of income reflect the impact of the Reorganization Events, including adopting fresh-start reporting effective as of the beginning of the period presented, and the completion of the Refinancing Transactions.

(2) Reflects an adjustment to increase interest expense to reflect the completion of the Refinancing Transactions effective as of the beginning of each of the periods presented.

(3) Upon the adoption of fresh start reporting, among other adjustments to the balance sheet, depreciable property, plant and equipment has been written down to an estimated fair value and newly determined depreciable lives have been adopted. Accordingly, depreciation expense has been adjusted to reflect the lower depreciable property, plant and equipment balances.

(4) Reflects adjustments to eliminate the impact of reorganization costs incurred subsequent to commencing bankruptcy proceedings on May 14, 2003. These amounts primarily relate to financial advisor and legal fees.

(5) Upon emergence from bankruptcy, in accordance with the NRG plan of reorganization, approximately $5.2 billion of primarily corporate level debt has been eliminated. Accordingly, interest expense has been adjusted to reflect the reduction in outstanding debt balances. Partially offsetting this reduction in interest expense is an adjustment to increase interest expense to reflect the impact of a fresh start reporting adjustment to record certain debt balances at fair value.

NRG ENERGY, INC. AND SUBSIDIARIES

UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET

	September 30, 2003			
		Pro Forma Adjustments		
	Historical	Reorganization Events(1)	Refinancing Transactions(2)	Pro Forma
	(Dollars in thousands)			
ASSETS				
Current Assets				
Cash and cash equivalents	$ 292,644	$ —	$ (119,067)(3)	$ 173,577
Restricted cash	487,644	—	250,000 (5)	737,644(4)
Accounts receivable	383,631	—	—	383,631
Inventory	255,803	—	—	255,803
Other current assets	224,068	702,889 (6),(7)	—	926,957
Total current assets	1,643,790	702,889	130,933	2,477,612
Property, Plant and Equipment, net	6,053,783	(1,596,202)(6)	—	4,457,581
Other assets				
Investments in projects	954,602	(146,687)(6)	—	807,915
Other long term assets	1,522,597	(290,269)(6)	66,000	1,298,328
Total other assets	2,477,199	(436,956)	66,000	2,106,243
Total Assets	$10,174,772	$ (1,330,269)	$ 196,933	$9,041,436
LIABILITIES AND STOCKHOLDERS' (DEFICIT)/ EQUITY				
Current Liabilities				
Current portion of long-term debt	$ 1,444,450	$ (725,098)(8)	$ (406,560)	$ 312,792
Short term debt	18,991	—	—	18,991
Accounts payable	307,641	580,919 (9)	—	888,560
Other current liabilities	318,224	205,466 (6)	(18,048)	505,642
Total current liabilities	2,089,306	61,287	(424,608)	1,725,985
Long term debt	1,188,599	1,381,623 (8)	1,950,000	4,520,222
Other long term obligations	491,757	(100,393)(6)	—	391,364
Total liabilities not subject to compromise	3,769,662	1,342,517	1,525,392	6,637,571
Financing debt	6,409,964	(5,102,714)(10)	(1,307,250)	—
Other liabilities	1,526,363	(1,524,763)(10)	(1,600)	—
Total liabilities subject to compromise	7,936,327	(6,627,477)	(1,308,850)	—
Total Stockholders (Deficit)/ Equity	(1,531,217)	3,954,691 (11)	(19,609)	2,403,865
Total Liabilities and Stockholder's (Deficit)/ Equity	$10,174,772	$ (1,330,269)	$ 196,933	$9,041,436

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET

(1) Reflects the discharge of debt and liabilities in accordance with the NRG plan of reorganization, and the impact of adopting fresh-start reporting effective as of September 30, 2003.

(2) Reflects the completion of the Refinancing Transactions.

(3) Includes $119.1 million of cash used to pay fees and expenses related to the Refinancing Transactions.

(4) Reflects $293.4 million of restricted cash at Northeast, South Central, Mid-Atlantic and PMI that may become unrestricted upon closing of the Refinancing Transactions.

(5) Consists of $250.0 million of the proceeds from the term loan facility used to pre-fund the letter of credit sub facility under the New Credit Facility that will be classified as restricted cash.

(6) Includes the adjustment of carrying amount to estimated fair market value. These adjustments are preliminary and subject to further revisions and adjustments, pending an update based on the actual amounts and applicable economic conditions as of the date of fresh start reporting.

(7) Includes $640.0 million for a receivable from Xcel Energy related to the settlement of the bankruptcy.

(8) Represents the reclassification of $946.4 million of debt from current to long term as a result of the remedy of cross-defaults through the bankruptcy proceeding, debt proceeds of $2.5 billion, $500.0 million of Plan Notes to be distributed to our unsecured creditors, debt eliminated or restructured of $6.8 billion and a mark-to-market adjustment of $92.0 million.

Debt consists of:	
Term loan facility	$ 950.0
Senior notes	1,000.0
Plan Notes	500.0
Xcel Energy Note	10.0
Existing non-guarantor debt	1,844.8
Capital leases	547.2
Total debt and capital leases	$4,852.0

(9) Represents a $540.0 million bankruptcy settlement of NRG Energy claims and the reinstatement of certain other claims of approximately $40.9 million.

(10) Represents the discharge or reinstatement of all prepetition liabilities as a result of the Reorganization Events.

(11) Represents elimination of beginning retained deficit of $1.5 billion, $640.0 million contribution from Xcel Energy, $2.6 billion gain on extinguishment of debt, $2.4 billion of new stock issued related to bankruptcy and $3.2 billion reduction of equity for the effect of implementing fresh-start reporting.

SELECTED HISTORICAL FINANCIAL DATA

The following table sets forth certain historical financial data of NRG Energy, Inc. We have derived the selected historical consolidated financial data as of and for the fiscal years ended December 31, 2000, 2001 and 2002 from our audited financial statements. Our consolidated financial statements as of and for fiscal 2000, 2001 and 2002 have been audited by PricewaterhouseCoopers LLP. For more information, see “Independent Accountants.” The selected historical consolidated financial data as of and for the fiscal years ended December 31, 1998 and 1999 have been derived from our audited consolidated financial statements for such years, which are not included in this report. We have derived the selected historical consolidated financial data for the nine-month periods ended September 30, 2002 and 2003 from our unaudited consolidated financial statements and the related notes included elsewhere in this report. In the opinion of our management, the unaudited consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation of our financial position and the results of our operations. The results of operations for the nine-month period ended September 30, 2003 are not necessarily indicative of the operating results to be expected for the full fiscal year. The selected historical financial data set forth below is not necessarily indicative of the results of future operations and should be read in conjunction with the discussion under the heading “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the historical consolidated financial statements and accompanying notes included elsewhere in this report.

	Year Ended December 31,					Nine Months Ended September 30,	
	1998	1999	2000	2001	2002	2002	2003
(Dollars in thousands)						(Unaudited)	
Income Statement Data:							
Total operating revenues and equity earnings	$178,719	$490,395	$1,808,895	$2,401,184	$ 2,157,428	$ 1,671,775	$1,772,627
Write downs and losses on equity method investments	—	—	—	—	200,472	127,715	136,717
Legal settlement	—	—	—	—	—	—	396,000
Reorganization items	—	—	—	—	—	—	27,032
Restructuring and impairment charges	—	—	—	—	2,627,766	2,533,670	298,019
Total operating costs and expenses	115,929	375,795	1,316,248	1,768,269	4,695,252	4,073,947	2,375,069
Minority interest earnings/losses of consolidated subsidiaries	(731)	(864)	(840)	(1,847)	(1,290)	(1,317)	(2,415)
Income/(loss) from continuing operations	38,043	53,562	149,566	223,802	(2,856,216)	(2,527,639)	(959,781)
Income/(loss) from discontinued operations	3,689	3,633	33,369	41,402	(608,066)	(595,570)	53,954
Net Income/(loss)	41,732	57,195	182,935	265,204	(3,464,282)	(3,123,209)	(905,827)
Other Financial Data and Ratios:							
Capital expenditures, net	$ 31,719	$ 94,853	$ 223,560	$1,322,130	$ 1,439,733	$ 1,391,019	$ 85,635
Depreciation and amortization	13,299	33,083	94,078	163,014	241,521	176,686	203,050
EBITDA(1)(3)	90,563	167,830	625,050	855,204	(2,901,427)	(2,807,932)	(339,929)
Adjusted EBITDA(2)(3)	86,874	164,197	591,681	813,802	534,877	449,023	463,885
Ratio of earnings to fixed charges(4)	1.0x	1.1x	1.8x	1.3x	—	—	—

(Dollars in thousands)	Year Ended December 31, 1998	1999	2000	2001	2002	Nine Months Ended September 30, 2002 (Unaudited)	2003
Balance Sheet Data (at period end):							
Cash and cash equivalents	$ 6,148	$ 30,697	$ 36,816	$ 105,405	$ 381,514	$ 325,902	$ 292,644
Restricted cash	4,021	2,504	7,236	140,323	277,489	207,503	487,644
Total Assets	1,238,630	3,436,403	5,978,992	12,916,260	10,892,783	11,688,413	10,174,772
Long Term Debt:							
Recourse corporate level debt	375,000	915,000	1,504,386	3,669,900	2,998,280	4,072,382	4,088,499
Non-recourse project level debt	116,233	790,634	1,689,954	3,648,971	5,212,778	4,125,961	3,940,299
Total long term debt including maturities	491,233	1,705,634	3,194,340	7,318,871	8,211,058	8,198,343	8,028,798
Stockholders' equity (deficit)	579,332	893,654	1,462,088	2,237,129	(696,199)	(326,660)	(1,531,217)

(1) EBITDA represents net income before interest, taxes, depreciation and amortization. We present EBITDA because we consider it an important supplemental measure of our performance and believe it is frequently used by securities analysts, investors and other interested parties in the evaluation of companies in our industry. EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our operating results as reported under GAAP. Some of these limitations are:

- EBITDA does not reflect our cash expenditures, or future requirements for capital expenditures, or contractual commitments;
- EBITDA does not reflect changes in, or cash requirements for, our working capital needs;
- EBITDA does not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments, on our debts;
- Although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA does not reflect any cash requirements for such replacements; and
- Other companies in our industry may calculate EBITDA differently than we do, limiting its usefulness as a comparative measure.

Because of these limitations, EBITDA should not be considered as a measure of discretionary cash available to use to invest in the growth of our business. We compensate for these limitations by relying primarily on our GAAP results and using EBITDA and Adjusted EBITDA only supplementally. See the statements of cash flow included in our financial statements that are a part of this report.

(2) We present Adjusted EBITDA as a further supplemental measure of operating performance. We prepare Adjusted EBITDA by adjusting EBITDA to eliminate the impact of a number of items we do not consider indicative of future operating performance. You are encouraged to evaluate each adjustment and the reasons we consider it appropriate for supplemental analysis. As an analytical tool, Adjusted EBITDA is subject to all of the limitations applicable to EBITDA. In addition, in evaluating Adjusted EBITDA, you should be aware that in the future we may incur expenses similar to the adjustments in this presentation. Our presentation of Adjusted EBITDA should not be construed as an inference that our future results will be unaffected by unusual or non-recurring items.

Adjusted EBITDA is calculated by adding to EBITDA certain expense items and deducting from EBITDA certain income items that we believe are unusual and not indicative of our future operating performance. For additional information regarding these adjustments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our audited financial statements and unaudited financial statements included elsewhere in this report.

(3) The following table summarizes the calculation of EBITDA and Adjusted EBITDA and provides a reconciliation to net income for the periods indicated:

	Year Ended December 31,					Nine Months Ended September 30,	
	1998	1999	2000	2001	2002	2002	2003
(Dollars in thousands)						(Unaudited)	
Net income/(loss)	$ 41,732	$ 57,195	$ 182,935	$ 265,204	$(3,464,282)	$(3,123,209)	$ (905,827)
Plus:							
Income tax (benefit)/ expense	(13,707)	(13,640)	98,360	39,298	(163,236)	(150,755)	44,864
Interest expense	49,239	91,192	249,677	387,688	484,570	289,346	317,984
Depreciation and amortization expense	13,299	33,083	94,078	163,014	241,521	176,686	203,050
EBITDA	$ 90,563	$167,830	$ 625,050	$ 855,204	$ (2,901,427)	$(2,807,932)	$(339,929)
Plus:							
(Income)/loss on discontinued operations, net of income tax	(3,689)	(3,633)	(33,369)	(41,402)	608,066	595,570	(53,954)
Legal settlement	—	—	—	—	—	—	396,000
Reorganization items	—	—	—	—	—	—	27,032
Restructuring and impairment charges	—	—	—	—	2,627,766	2,533,670	298,019
Write downs and losses on sales of equity method investments	—	—	—	—	200,472	127,715	136,717
Adjusted EBITDA	$ 86,874	$164,197	$ 591,681	$ 813,802	$ 534,877	$ 449,023	$ 463,885

(4) The ratio of earnings to fixed charges is computed by dividing earnings by fixed charges. For this purpose, “earnings” includes pre-tax income (loss) before adjustments for minority interest in our consolidated subsidiaries and income or loss from equity investees, plus fixed charges and distributed income of equity investees, reduced by interest capitalized. “Fixed charges” include interest, whether expensed or capitalized, amortization of debt expense and the portion of rental expense that is representative of the interest factor in these rentals. Earnings were insufficient to cover fixed charges by approximately $3.1 billion, $2.7 billion and $960.0 million for the periods ended December 31, 2002, September 30, 2002 and September 30, 2003, respectively.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion in conjunction with the sections in this report titled "Forward-Looking Statements," "Risk Factors," "Selected Historical Financial Data" and the financial statements and related notes thereto included elsewhere in this report.

Overview

We are a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type and dispatch levels, which helps us mitigate risk. We intend to maximize operating income through the efficient procurement and management of fuel supplies and maintenance services, and the sale of energy, capacity and ancillary services into attractive spot, intermediate and long-term markets. On a pro forma basis after giving effect to the Reorganization Events and the Refinancing Transactions, we generated total operating revenues and equity earnings of approximately $2.3 billion and Pro Forma Adjusted EBITDA of approximately $549.7 million for the twelve-month period ending September 30, 2003.

We do not anticipate any significant new acquisitions or construction in the near future, and instead will focus on operational performance, asset management and debt reduction. We have already made significant reductions in capital expenditures, business development activities and personnel. Power sales, fuel procurement and risk management will remain key strategic elements of our operations. Our objective will be to optimize the operating income of our facilities within an appropriate risk and liquidity profile.

Industry Trends. In this "Management's Discussion and Analysis of Financial Condition and Results of Operations," we discuss our historical results of operations and expected financial condition upon emergence from the bankruptcy proceedings as described elsewhere in this report. During 2002 and 2003, the following factors, among others, have negatively affected our results of operations:

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

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

Asset Sales. As part of our strategy, we plan to continue the selective divestment of certain assets to further reduce indebtedness. Since July 2002 we have sold or made arrangements to sell a number of assets and equity investments in an effort to raise cash and reduce our debt. In addition, we are currently marketing our interest in several other assets. For more information relating to closed and pending asset dispositions, see “Business — Significant Dispositions of Non-Strategic Assets.”

Discontinued Operations. We have classified certain business operations, and gains/losses recognized on sale, as discontinued operations for projects that were sold or have met the required criteria for such classification pending final disposition. Accounting regulations require that continuing operations 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 September 30, 2003 include McClain and Hsin Yu. For the nine months ended September 30, 2003, discontinued results of operations include our Killingholme, Hsin Yu, McClain, NEO Landfill Gas, Inc., or “NLGI,” and Timber Energy Resources, Inc., or “TERI,” projects.

New Management. On October 21, 2003, we announced the appointment of David W. Crane as our new President and Chief Executive Officer, effective December 1, 2003. Before joining NRG Energy, Mr. Crane served as the Chief Executive Officer of London-based International Power PLC and has over 12 years of energy industry experience. We are currently conducting a search for a new Chief Financial Officer. We anticipate the position will be filled in the months following our emergence from bankruptcy. In addition, we have filled several other senior and middle management positions over the last 12 months. Upon emergence from bankruptcy, our board of directors will consist of Mr. Crane and ten other individuals, three of whom have been designated by MatlinPatterson, and seven of whom are independent. For more information, see “Management.”

Independent Public Accountants; Audit Committee. PricewaterhouseCoopers LLP has been our independent auditors since 1995. In connection with the appointment of a new board of directors upon our emergence from bankruptcy, we will have an audit committee consisting entirely of independent directors. The operations of the audit committee will be governed by a charter. Pursuant to the charter, the committee will oversee our independent auditor relationship and determine whether our best interest would be served by changing independent auditors. The audit committee’s evaluation process is intended to ensure that we will continue to have high-quality, cost-efficient independent auditing services.

Fresh-Start Reporting. Upon emergence from bankruptcy and completion of the restructuring, we will implement fresh-start reporting. Under fresh-start reporting, a new reporting entity is considered to be created and our reorganizational value will be allocated to our assets based on their respective fair values in conformity with the purchase method of accounting for business combinations, and our assets’ recorded values will be adjusted to reflect their estimated fair values at the date fresh-start reporting is applied. Any portion of our reorganization value not attributable to specific assets will be an indefinite-lived intangible asset referred to as “reorganization value in excess of the value of identifiable assets” and reported as goodwill. Any excess fair value of assets and liabilities over confirmed enterprise value will be allocated as a pro rata reduction of the amounts that otherwise would have been assigned to all of the assets except financial assets other than investments accounted for by the equity method, assets to be disposed of by sale, deferred tax assets, prepaid assets relating to pension or other postretirement benefit plans and any other current assets. As a result of adopting fresh-start reporting and emerging from bankruptcy, historical financial information will not be comparable to financial information for future periods after our emergence from bankruptcy.

Results of Operations

Comparison of the nine months ended September 30, 2003 and September 30, 2002

Net (Loss)/ Income

For the nine months ended September 30, 2003, we recognized a net loss after discontinued operations of $905.8 million compared to a net loss after discontinued operations of $3.1 billion for the same period in 2002.

We incurred impairment charges of $229.6 million for the nine months ended September 30, 2003 and $2.5 billion for the same period in 2002. During the second quarter of 2003, we received unfavorable FERC orders related to our Connecticut facilities, which resulted in an impairment charge of $221.5 million. Credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity experienced by us 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 certain of our operational projects were impaired during the third quarter of 2002 and were written down to fair market value. We incurred write downs of equity method investments of $136.7 million for the nine months ended September 30, 2003 and $127.7 million for the same period in 2002. The write downs for the nine months ended September 30, 2003 and 2002 consisted primarily of permanent reductions in the value of our Loy Yang project and SRW Cogeneration LP project and were based on a third party market valuation and updated market values received in response to marketing Loy Yang for possible sale. During the nine months ended September 30, 2003, we incurred reorganizational and restructuring charges of $95.5 million, which primarily consisted of advisor and other professional fees. For the same period ended September 30, 2002, we incurred restructuring charges of $37.7 million, which consisted of employee separation costs and advisor fees. During the third quarter of 2003, we recorded a $396.0 million charge in connection with the resolution of the FirstEnergy Arbitration Claim. This amount is recorded on the balance sheet as a prepetition liability. For more information, see "Business—Legal Proceedings—FirstEnergy Arbitration Claim."

We incurred a net loss before impairment and restructuring charges, write downs of equity method investments and a loss on legal settlement of $48.1 million for the nine months ended September 30, 2003 compared to $461.8 million for the same period in 2002, representing a decreased loss of $413.7 million. The lower net loss for 2003 is attributed to increased revenues from majority-owned operations for the nine months ended September 30, 2003 compared to the same period in 2002 due to higher market prices driven by higher natural gas prices and due to an increase in capacity revenues due to additional projects becoming operational in the middle of 2002 and higher sales in New York. In addition, equity in operating earnings of unconsolidated affiliates increased for the nine months ended September 30, 2003 compared to the same period in 2002 due to favorable results at our West Coast Power project resulting from increased ancillary and RMR contract revenues. The sale of our investment in MESI in 2002 also resulted in a favorable impact in 2003, as MESI generated substantial equity losses in the prior year. These favorable items were offset by losses incurred on the Connecticut Standard Offer contracts due to increased market prices, increased operating expenses, contract terminations and liquidated damages triggered by our financial condition and additional restructuring charges.

Operating Revenues and Equity Earnings

For the nine months ended September 30, 2003, we had total operating revenues and equity earnings from continuing operations of $1.8 billion, compared to $1.7 billion for the same period in 2002.

Revenues from Majority-Owned Operations

During the nine months ended September 30, 2003, we recorded revenues from majority-owned operations of $1.6 billion, compared to $1.6 billion for the same period in 2002. Revenues from majority-owned operations for the nine months ended September 30, 2003, consisted primarily of power generating revenues from domestic operations of approximately $1.2 billion, European operations of $96.3 million, Asia-

Pacific operations of $131.2 million and Latin American operations of $57.0 million. In addition, we recognized revenues from majority-owned operations from Alternative Energy, Thermal and Other Operations of $68.4 million, $87.7 million and $4.6 million, respectively.

Revenues from majority-owned operations of $1.6 billion for the nine months ended September 30, 2003 includes $788.5 million of energy revenues, $504.7 million of capacity revenues, $143.6 million of alternative and thermal revenues, $29.8 million of changes in the fair market value of derivatives calculated in accordance with FAS No. 133, $10.9 million of operating and maintenance fees and $139.3 million of other revenues, which include financial and physical gas sales, sales from our Schkopau facility and New England Power Pool (NEPOOL) expense reimbursements. Revenues from majority-owned operations increased $14.0 million, or 1%, from the prior period. This increase is due to energy revenues, capacity revenues and changes in the fair market value of derivatives calculated in accordance with FAS No. 133. Energy revenues increased due to higher market prices driven by higher natural gas prices during the first quarter of 2003, as compared to the same period in 2002, attributable to our North America operations. Capacity revenues increased due to additional projects becoming operational in the later part of 2002 and higher sales in New York. FAS No. 133 revenue was favorable due to the termination of unfavorable financial transactions in 2003. These increases were offset by losses incurred on the Connecticut Standard Offer contracts due to increased market prices and a reduction in other revenues due to lower sales of natural gas.

Equity in Operating Earnings of Unconsolidated Affiliates

Equity in operating earnings of unconsolidated affiliates for the nine months ended September 30, 2003 was $155.8 million compared to $68.9 million for the same period in 2002.

Equity in operating earnings of unconsolidated affiliates of $155.8 million for the nine months ended September 30, 2003 includes $114.8 million from the domestic portfolio and $43.0 million from the international portfolio, offset by $2.0 million of equity losses in the Alternative Energy portfolio. Equity in operating earnings of unconsolidated affiliates for the nine months ended September 30, 2003 increased $86.8 million, or 126%, compared to the same period in 2002. This increase is due to favorable results at West Coast Power as compared to the same period in 2002, resulting from increased ancillary and RMR contract revenues and other revenues. The sale of NRG Energy's investment in MESI in 2002 also resulted in a favorable impact in 2003, as MESI generated substantial losses in the prior years.

Cost of Majority-Owned Operations

Cost of majority-owned operations was $1.2 billion for the nine months ended September 30, 2003, compared to $1.1 billion for the same period in 2002. Costs of majority-owned operations include fuel and related costs, operation and maintenance costs, or "O&M," property taxes and the mark-to-market of certain fuel contracts and emission credits.

Cost of majority-owned operations for the nine months ended September 30, 2003 increased $122.2 million, or approximately 11.5%, over the same period in 2002. Cost of majority-owned operations, as a percentage of revenue from majority-owned operations for the nine months ended September 30, 2003, was 73.4% compared to 66.4% for the same period in 2002. This increase in expense is primarily due to contract terminations and liquidated damages of approximately $72.0 million triggered by our financial condition. The contract terminations and liquidated damages are related to long-term electricity and fuel transactions. Offsetting this expense was a favorable change in the fair value of our energy related derivatives directly resulting from the termination of these contracts. In addition, the overall cost of fuel and transmission increased as compared to the same period in 2002 due to increased fuel prices. The increase in fuel and transmission expense was offset by a decrease in generation levels. O&M expenses also increased due to increased maintenance to improve plant availability and to ensure emission compliance. Property tax expense increased due to assessments related to assets placed in service during mid-2002 and higher assessments by taxing authorities.

Depreciation and Amortization

Depreciation and amortization costs were $203.1 million for the nine months ended September 30, 2003, compared to $176.7 million for the same period in 2002, an increase of $26.4 million, or 14.9%. This increase was primarily due to reducing the depreciable lives for certain Connecticut assets, which increased the depreciation expense by $13.9 million over the same period in 2002. In addition, depreciation expense increased due to completed construction projects being placed in service. 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. The increase in depreciation expense was partially offset due to reduced asset values based on our impairment analysis.

General, Administrative and Development Expense

General, administrative and development costs were $128.0 million for the nine months ended September 30, 2003, compared to $171.9 million for the same period in 2002. General, administrative and development costs include non-operational labor and other employee related costs, as well as outside services, insurance, office expenses and administrative support.

General, administrative and development costs for the nine months ended September 30, 2003 decreased $43.9 million, or 25.5%, over the same period in 2002. General, administrative and development costs, as a percentage of revenue from majority-owned operations for the nine months ended September 30, 2003, was 7.9% compared to 10.7% for the same period in 2002. This decrease is due to decreased costs related to work force reduction efforts, cost reductions due to the closure of certain international offices and reduced legal costs. Outside services also decreased due to less non-restructuring related legal activities. Partially offsetting these favorable variances was an increase in bad debt expense at both our domestic and international operations.

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

Write downs and (gains)/losses on equity method investments was $136.7 million for the nine months ended September 30, 2003 compared to $127.7 million for the same period in 2002.

Write downs and (gains)/losses on equity method investments for the nine month period ended September 30, 2003 consisted primarily of permanent reductions in the value of our Loy Yang project. In May 2003, we and our partners completed negotiations, which culminated in the completion of a share purchase agreement to sell 100% of the project. Completion of the sale is subject to various conditions. Upon completion, the sale will result in proceeds of approximately $25.0 million to $31.0 million to us. Consequently, we recorded an impairment charge of approximately $140.0 million during the quarter ended June 30, 2003. This charge included approximately $61.0 million of foreign currency translation losses related to the investment in Loy Yang, in accordance with EITF Issue No. 01-05 *"Application of FASB Statement No. 52 to an Investment Being Evaluated for Impairment that will be Disposed of."* Offsetting this charge is a net gain of approximately $12.1 million relating to the sale of our interest in Mustang Station.

Write-downs and (gains)/losses on equity method investments for the nine month period ended September 30, 2002 consisted primarily of our Loy Yang project and SRW Cogeneration LP project.

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 $53.6 million during the third quarter of 2002 and an additional $57.8 million during the fourth quarter of 2002. This write-down reflected management's belief that the decline in fair value of the investment was other than temporary.

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. We recorded a charge of approximately $49.4 million during the quarter ended September 30, 2002 to write down the carrying value of its investment due to the pending sale. The transaction closed on November 5, 2002.

Restructuring and Impairment Charges and Legal Settlement Costs

Restructuring and impairment charges and legal settlement costs were $721.1 million for the nine months ended September 30, 2003 compared to $2.5 billion for the same period in 2002. Asset impairment charges were $229.6 million for the nine months ended September 30, 2003 compared to $2.5 billion for the nine months ended September 30, 2002. Reorganizational and restructuring costs were $95.5 million for the nine months ended September 30, 2003 compared to $37.7 million for the nine months ended September 30, 2002. We recorded a charge of $396.0 million in the third quarter ended September 30, 2003 in connection with resolution of the FirstEnergy Arbitration Claim.

Additional asset impairments and other charges may be recorded by us in periods subsequent to September 30, 2003, given the changing business conditions and the resolution of the pending restructuring plan. Management is unable to determine the possible magnitude of any additional asset impairments.

Impairment charges for the nine month period ended September 30, 2003 consisted of charges taken primarily at Devon Power LLC and Middletown Power LLC. As a result of the implementation of PUSH bidding at our Connecticut facilities and other regulatory developments and changing circumstances in the second quarter, as discussed further in "Business— Power Generation— Eastern Region" and in item 1— note 4 to the consolidated financial statements included elsewhere in this report, we deemed it necessary to review the Connecticut facilities' cash flow models to incorporate changes to reflect the impact of FERC's April 25, 2003 orders on PUSH pricing and update the estimated impact of future locational pricing. These revised cash flow models determined that the new estimates of pricing and cost recovery levels were not projected to provide sufficient revenue to cover the fixed costs at Devon Power LLC and Middletown Power LLC. As a consequence, at June 30, 2003, we recorded a $221.5 million impairment charge at Devon Power LLC and Middletown Power LLC.

Credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity experienced by us 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 its operational projects were impaired during the third quarter of 2002 and should be written down to fair market value. Our management considered cash flow analyses, bids and offers related to those projects. These impairments of several of our assets were recognized as impairment charges in the third quarter of 2002. See Item 1 — Note 4 to the consolidated financial statements included elsewhere in this report for additional information.

During the third quarter of 2003, we recorded $396.0 million in connection with the resolution of the FirstEnergy Arbitration Claim. As a result of this resolution, First Energy will retain ownership of the Lake Plant Assets and will receive an allowed general unsecured claim of $396.0 million under our plan of reorganization submitted to the bankruptcy court. In accordance with SOP 90-7, this amount is recorded on the balance sheet as a pre-petition liability. We also recorded approximately $42.0 million of a contingent equity obligation in connection with our Brazos Valley Project as a result of the project lenders entering into a sales agreement whereby they agreed to sell the Brazos Valley project for a lower sales price than originally estimated. This contingent equity obligation is recorded as a restructuring charge. The remaining charges consist primarily of employee separation costs and advisor fees. During the second quarter of 2003, a settlement agreement with former NRG executives was accepted that resulted in a lower severance cost relating to the executives. As a result, approximately $8.4 million was reversed out of the severance accrual during second quarter 2003.

We incurred $37.7 million of restructuring costs for the nine months ended September 30, 2002. These costs consist primarily of employee separation costs and advisor fees. During second and third quarter of 2002, we expensed a pre-tax charge of $20.5 million and $5.7 million for expected severance costs associated with our combining of various functions.

Other (Expense) Income

Other expense for the nine months ended September 30, 2003 was $312.5 million compared to $276.2 million, for the same period in 2002. Other expense for the nine months ended September 30, 2003 increased $36.3 million or 13.1% over the same period in 2002. This increase was primarily due to an increase in interest expense, including both corporate and project level interest expense. The increase in interest expense is due to increased debt balances and the completion of certain construction projects, which resulted in a reduction in the amount of capitalized interest in 2003 compared to 2002. This increase was partially offset by ceasing to record interest expense on debt, such as certain NRG corporate level debt and NRG FinCo debt, where it was determined that such interest would not be paid due to our bankruptcy filing. Other expense was also adversely affected due to an unfavorable mark-to-market on certain interest rate swaps not accounted for as cash flow hedges and an unfavorable mark-to-market of the British pound sterling 160 million corporate level debt.

Income Tax

Income tax benefit/expense for the nine months ended September 30, 2003 was a tax expense of $44.9 million compared to a tax benefit of $150.8 million for the same period in 2002. The income tax expense for 2003 was primarily due to separate company tax liabilities and an increase in the valuation allowance against deferred tax assets. An additional valuation allowance of $33.0 million was recorded against the deferred tax assets of NRG West Coast as a result of its conversion from a corporation to a disregarded entity for federal income tax purposes. The income tax benefit for 2002 was primarily due to the increase in deferred tax assets relating to impairments recognized for financial reporting purposes. A valuation allowance was established limiting the recognition of deferred tax assets to the extent of previously-recorded deferred tax liabilities.

Income taxes have been recorded on the basis that Xcel Energy will not be including us in its consolidated federal income tax return following Xcel Energy’s acquisition of our public shares on June 3, 2002. Since Xcel Energy has decided not to include us in its consolidated federal income tax return, we and each of our subsidiaries must file separate federal income tax returns. A tax saving strategy has been implemented to reduce the current taxes due for those subsidiaries with taxable income for 2003. As part of this strategy, NRG West Coast was converted to a disregarded entity so its taxable income will flow up and be offset by our tax losses. This conversion was completed to reduce current tax payments for 2003. It is uncertain if we will be able to fully realize tax benefits on net operating losses and deferred tax assets. Consequently, a valuation allowance of approximately $1.4 billion has been recorded as of September 30, 2003.

Discontinued Operations

As of September 30, 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 nine months ended September 30, 2003, discontinued operations consist of the historical operations and net gains/losses related to our Killingholme, Hsin Yu, McClain, NLGI, and TERI projects. Discontinued operations for the same period in 2002 consist of our Crockett Cogeneration, Entrade, Killingholme, Csepel, Hsin Yu, Bulo Bulo, McClain, NLGI and TERI projects.

For the nine months ended September 30, 2003, the results of operations related to such discontinued operations was a net gain of $54.0 million compared to a net loss of $595.6 million for the same period in 2002. The primary reason for the gain recognized during 2003 was the completion of the sale of our interest in Killingholme resulting in a net gain of $191.2 million, offset by impairment charges recorded at McClain and NLGI. The primary reason for the loss recognized during 2002 was due to asset impairments recorded at Killingholme, Hsin Yu, NLGI and TERI projects.

Comparison of the Years Ended December 31, 2002 and December 31, 2001

Net Loss

During the year ended December 31, 2002, we recognized a net loss of $3.5 billion. This loss represented a decrease in earnings of $3.7 billion compared to net income of $265.2 million for the same period in 2001. Our loss from continuing operations was $2.9 billion for the year ended December 31, 2002 compared to net income of $223.8 million from continuing operations for the same period in 2001. The loss from continuing operations incurred during 2002 primarily consists of $2.6 billion of special charges consisting primarily of asset impairments.

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

During the third quarter of 2002, we experienced credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity. These events led to impairments of a number of our assets, resulting in pre-tax charges related to continuing operations of approximately $2.5 billion during 2002. In addition, approximately $200.5 million of net losses on sales and write-downs of equity method investments were recorded in 2002. Operating results of majority-owned projects that were sold or have met the criteria to be considered as held-for-sale have been classified as discontinued operations.

As of December 31, 2002, our Killingholme, Hsin Yu, McClain, TERI and NEO Landfill Gas projects were classified as discontinued operations. The sales of Bulo Bulo, Csepel, Entrade and Crockett had been completed. In addition, the sale of our investments in Mt. Poso, Collinsville, EDL, Sabine River Works, Kingston and NEO MESI had also taken place. The sale of our investment in ECKG was pending at the end of 2002, and was completed in January 2003, along with the transfer of our ownership interest in the Killingholme and the transfer of the ownership interest in the Brazos Valley project to its lenders. In the second and third quarters of 2003, the transfer of the NEO Landfill Gas assets and the sale of the TERI project were also completed. In addition, the sale of our interest in Kondapalli and Mustang Station were completed in the second and third quarters of 2003.

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

Revenues and Equity in Earnings of Unconsolidated Affiliates

During 2002, total operating revenues and equity earnings from continuing operations were $2.2 billion compared to $2.4 billion in the prior year, a decrease of $243.8 million, or 10.2%. The primary reason for this decrease was a reduction in equity earnings from unconsolidated affiliates of $141.0 million. The $141.0 million decrease in equity earnings from unconsolidated affiliates is due primarily to lower results at West Coast Power in 2002 as compared to the same period in 2001. During 2002, West Coast Power had long-term contracts that were less favorable than those held in 2001. In addition during 2002, West Coast Power established reserves for certain receivables not considered recoverable. Our share of this reserve was approximately $58.5 million on a pre-tax basis.

Revenues from Majority-Owned Operations

Our operating revenues from majority-owned operations were $2.1 billion in 2002 compared to $2.2 billion in the prior year, a decrease of $102.8 million or approximately 4.7%. Revenues from majority-owned operations for the year ended December 31, 2002, consisted primarily of power generation revenues from domestic operations of approximately $1.5 billion in 2002 compared with $1.7 billion in 2001, a decrease of $140.4 million. This decrease in domestic generation revenue is due to reductions in energy and capacity sales and an overall decrease in power pool prices.

Within the North American segment, the Eastern region experienced decreased revenues. The Eastern region revenues were significantly affected by a combination of lower capacity revenues and a decline in megawatt hour generation compared with 2001. This decline in generation is attributable to an unseasonably warm winter and cooler spring and a slowing economy which reduced demand for electricity, together with new regulation which reduced price volatility, particularly in New York City. The Central region generated increased revenues primarily due to a full year of operations compared to plants acquired and completed in 2001.

Our International revenues from majority-owned operations increased by $22.4 million or 7.1% from 2001 to 2002. The Asia Pacific region reported a reduction in revenues of $42.4 million while increases were reported from Europe of $34.9 million and Latin America of $29.9 million. The reduction in Asia Pacific revenue is primarily due to a decline in energy prices and the loss of a significant contract at Flinders. The increase in Europe and Latin America revenue is primarily due to a full year of operations for acquisitions made in 2001.

Equity in Earnings of Unconsolidated Affiliates

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

Operating Costs and Expenses

For the year ended December 31, 2002, cost of majority-owned operations related to continuing operations was $1.4 billion compared to $1.4 billion for 2001, a decrease of $13.0 million or approximately 0.9%. For the years ended December 31, 2002 and 2001, cost of majority-owned operations represented approximately 67.0% and 64.4% of revenues from majority-owned operations, respectively. Cost of majority-owned operations consists primarily of cost of energy (primarily fuel costs), labor, operating and maintenance costs and non-income based taxes related to our majority-owned operations.

Cost of energy decreased from $977.4 million for the year ended December 31, 2001 to $922.1 million for the year ended December 31, 2002. This represents a decrease of $55.3 million or 5.7%. As a percent of revenue from majority-owned operations cost of energy was 44.6% and 44.6% for the years ended December 31, 2002 and 2001, respectively.

Operating and maintenance costs increased from $347.6 million for the year ended December 31, 2001 to $401.2 million for the year ended December 31, 2002. This represents an increase of $53.6 million or 15.4%. As a percent of revenue from majority-owned operations, operating and maintenance costs represented 19.2% and 16.0%, for the years ended December 31, 2002 and 2001, respectively. The dollar increase in operating and maintenance expense is primarily due to a full year of expense in 2002 related to assets acquired during 2001.

Depreciation and Amortization

For the year ended December 31, 2002, depreciation and amortization related to continuing operations was $241.5 million, compared to $163.0 million for the year ended December 31, 2001, an increase of $78.5 million or approximately 48.2%. This increase is primarily due to the addition of property, plant and equipment related to our recently completed acquisitions of electric generating facilities.

General, Administrative and Development Expense

For the year ended December 31, 2002, general, administrative and development costs were $226.5 million, compared to $193.2 million, an increase of $33.3 million or approximately 17.2%. For the year ended December 31, 2002 and 2001, general, administrative and development costs represent 10.8% and 8.8% of revenues from majority-owned operations, respectively. This increase is primarily due to an increase in bad debt expense of approximately $18.2 million over 2001. Additionally there was an increase in other general administrative expenses due to 2001 acquisitions and newly constructed facilities coming on line. These increases were partially offset by decreases in business development expenses and other reductions to costs previously incurred to support international and expanded operations.

Write-Downs and Losses on Sales of Equity Method Investments

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

Special Charges

During the third quarter of 2002, we experienced credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity. We applied the provisions of SFAS No. 144 to our construction and operational projects. We completed an analysis of the recoverability of the asset carrying values of our projects factoring in the probability of different courses of action available to us given our financial position and liquidity constraints. As a result, we determined during the third quarter that many of our construction projects and certain operational projects were impaired and should be written down to fair market value. To estimate fair value, our management considered discounted cash flow analyses, bids and offers related to those projects and prices of similar assets. During 2002, we recorded asset impairment and other special charges related to continuing operations of $2.6 billion. See Note 3 to the consolidated financial statements for additional information.

During 2002, we expensed charges of $25.6 million for expected severance costs, primarily related to terminated executives, associated with our restructuring, and of this amount, $4.7 million of cash was paid as of December 31, 2002.

Other Income (Expense)

For the year ended December 31, 2002, total other expense was $481.6 million, compared to $369.8 million for the year ended December 31, 2001, an increase of $111.8 million or approximately 30.2%. The increase in total other expense from 2001 consisted primarily of an increase in interest expense.

For the year ended December 31, 2002, interest expense (which includes both corporate and project level interest expense) was $484.6 million, compared to $387.7 million in 2001, an increase of $96.9 million or approximately 25.0%. This increase is due primarily to increased corporate and project level debt. We issued substantial amounts of long-term debt at both the corporate level (recourse debt) and project level (non-recourse debt) to either directly finance the acquisition of electric generating facilities or refinance short-term bridge loans incurred to finance such acquisitions.

For the year ended December 31, 2002, minority interest in earnings of consolidated subsidiaries was $1.3 million, compared to $1.8 million, a decrease of $0.6 million, as compared to 2001. This decrease is primarily due to increased earnings from COBEE for the year ended December 31, 2002.

Other income was a gain of $4.2 million, as compared to $19.7 million for the year ended December 31, 2001, a decrease of $15.5 million, or approximately 78.7%. Other income consists primarily of interest income on cash balances and realized and unrealized foreign currency exchange gains and losses. Interest income was lower during 2002 due to lower interest from affiliates, primarily related to West Coast Power. In addition, there were significant foreign currency exchange losses during 2002.

Income Tax

For the year ended December 31, 2002, the income tax benefit from continuing operations was $163.2 million and, for the year ended December 31, 2001, the income tax expense from continuing operations was $39.3 million The income tax benefit for 2002 was primarily due to the increase in deferred tax assets relating to impairments recognized for financial reporting purposes. A valuation allowance was established limiting the recognition of deferred tax assets to the extent of previously-recorded deferred tax liabilities. The income tax expense for 2001 was primarily due to U.S. and Foreign operating earnings, reduced by tax credits of $37.2 million.

For 2002, income taxes were recorded on the basis that Xcel Energy would not include us in its consolidated federal income tax return following Xcel Energy’s acquisition of our public shares on June 3, 2002. Since Xcel Energy did not include us in its consolidated federal income tax return, we and each of our subsidiaries must file separate federal income tax returns. It is uncertain if we will be able to fully realize tax benefits on net operating losses and deferred tax assets on a stand-alone basis. Also, as of December 31, 2002, NRG Energy management revised its strategy and no longer intended to indefinitely reinvest the full amount of earnings from foreign operations. However, no U.S. income tax benefit has been provided on the cumulative amount of unremitted foreign losses due to the uncertainty of realization. Consequently, a valuation allowance of $684.5 million has been recorded as of December 31, 2002.

For 2001, NRG Energy and its subsidiaries were included in the Xcel Energy consolidated federal income tax return through March 12, 2001, the date of our secondary public offering. For the remainder of the year, we filed a consolidated federal return with its subsidiaries. Income tax expense was recorded on current and deferred tax liabilities, partially offset by benefits from tax credits. As of December 31, 2001, our management intended to reinvest the earnings from foreign operations to the extent these earnings were subject to current U.S. income taxes. Accordingly, U.S. income taxes and foreign withholding taxes were not provided on a cumulative amount of unremitted foreign earnings of approximately $345.0 million.

Discontinued Operations

As of December 31, 2002, we classified the operations and gains/losses recognized on the sales of certain entities as discontinued operations. Discontinued operations consist of the historical operations and net gains/losses related to our Crockett Cogeneration, Entrade, Killingholme, Csepel, Hsin Yu, Bulo Bulo, McClain, NLGI and TERI projects that were sold in 2002 or were deemed to have met the required criteria for such classification pending final disposition (the Killingholme, Hsin Yu, TERI and NLGI projects). For 2002, the results of operations related to such discontinued operations was a net loss of $608.1 million as compared to a gain of $41.4 million for the same period in 2001. The primary reason for the loss recognized in 2002 is due to asset impairments recorded at Killingholme, Hsin Yu, TERI and NLGI.

Comparison of the Years Ended December 31, 2001 and December 31, 2000

Net Income

Net income for 2001 was $265.2 million, compared to $182.9 million for 2000, an increase of $82.3 million or approximately 45.0%. Net income for 2001 increased by $82.3 million due to the factors described below.

Revenues and Equity in Earnings of Unconsolidated Affiliates

For the year ended December 31, 2001, we had total revenues and equity earnings from continuing operations of $2.4 billion, compared to $1.8 billion for 2000, an increase of $592.3 million or approximately 32.7%.

Revenues from Majority-Owned Operations

Our operating revenues from majority-owned operations were $2.2 billion compared to $1.7 billion, an increase of $521.6 million or approximately 31.2%. Revenues from majority-owned operations for the year ended December 31, 2001 consisted primarily of power generation revenues from domestic operations of approximately $1.7 billion, operations in Europe of $72.5 million, operations in Asia-Pacific of $214.8 million and operations in Latin America of $28.2 million, resulting in increases of $225.6 million, $71.2 million, $120.0 million and $27.9 million compared to 2000, respectively. In addition, we recognized revenues from majority-owned operations from our alternative energy, thermal and other operations of approximately $74.8 million, $108.3 million and $18.5 million respectively, resulting in increases of $41.7 million, $23.4 million and $11.7 million compared to 2000, respectively.

The increase of $225.6 million related to our domestic power generation operations is due primarily to additional sales at the Eastern region facilities which were acquired in June 2001 from Conectiv and increased sales at the South Central region facilities which were primarily acquired in March 2000 from Cajun Electric and expanded with the acquisition of the Batesville facility from LS Power in January 2001 and completion of the Sterlington and Big Cajun 1 peaking facilities in 2001.

The increase of $71.2 million related to our Europe power generation operations is due primarily to operations at Saale Energie in Germany.

The increase of $120.0 million related to our Asia-Pacific's power generation operations is due primarily to a full year of operations at the Flinders Power facilities which was acquired in August 2000.

The increase of $27.9 million related to our Latin America power generation operations is due primarily to the consolidation in 2001 of the COBEE facility which was previously accounted for under the equity method.

Equity in Earnings of Unconsolidated Affiliates

For the year ended December 31, 2001, we had equity in earnings of unconsolidated affiliates of $210.0 million, compared to $139.4 million for 2000, an increase of $70.6 million or approximately 50.6%. The increase of $70.7 million primarily consists of favorable results from our domestic and international power generation equity investments. During 2001, our domestic power generation investment in West Coast Power contributed $41.0 million of this increase. Additionally, approximately $40.5 million of the increase is from our international power generation investments. These increases were partially offset by unfavorable results at our other investments accounted for under the equity method and continued reductions in the equity earnings attributable to NEO Corporation. NEO Corporation derives a significant portion of our net income from Section 29 tax credits.

Operating Costs and Expenses

For the year ended December 31, 2001, cost of majority-owned operations was $1.4 billion compared to $1.1 billion for 2000, an increase of $358.8 million or approximately 34.1%. For the years ended December 31, 2001 and 2000, cost of majority-owned operations represented approximately 64.4% and 63.1% of revenues from majority-owned operations, respectively. Cost of majority-owned operations consists primarily of cost of energy (primarily fuel costs), labor, operating and maintenance costs and non-income based taxes related to our majority-owned operations.

Cost of energy increased from $711.4 million for the year ended December 31, 2000 to $977.4 million for the year ended December 31, 2001 primarily due to 2001 domestic and international acquisitions. This represents an increase of $266.0 million or 37.4%. As a percent of revenue from majority-owned operations, cost of energy was 44.6% and 42.6% for the years ended December 31, 2001 and 2000, respectively.

Operating and maintenance costs increased from $260.1 million for the year ended December 31, 2000 to $347.6 million for the year ended December 31, 2001. This represents an increase of $87.5 million or 33.6%. As a percent of revenue from majority-owned operations operating and maintenance costs represented 15.7% and 15.6%, for the years ended December 31, 2001 and 2000, respectively. The dollar increase in operating and maintenance expense is primarily due to 2001 domestic and international acquisitions.

Depreciation and Amortization

For the year ended December 31, 2001, depreciation and amortization from continuing operations was $163.0 million, compared to $94.1 million for the year ended December 31, 2000, an increase of $68.9 million or approximately 73.3%. This increase is primarily due to the addition of property, plant and equipment related to our recently completed acquisitions of electric generating facilities.

General, Administrative and Development Expense

For the year ended December 31, 2001, general, administrative and development costs were $193.2 million, compared to $168.9 million, an increase of $24.3 million or approximately 14.4%. This increase is primarily due to increased business development activities, associated legal, technical and accounting expenses, employees and equipment resulting from expanded operations and pending acquisitions. This also includes a $10.3 million expense related to Enron's bankruptcy. This amount includes a pre-tax charge of $22.4 million to establish bad debt reserves, which was partially offset by a pre-tax gain of $12.1 million on a credit swap agreement entered into as part of the our credit risk management program.

Other Income (Expense)

For the year ended December 31, 2001, total other expense was $369.8 million, compared to $244.7 million for the year ended December 31, 2000, an increase of $125.1 million or approximately 51.1%. The increase in total other expense of $125.1 million, from 2000, consisted primarily of an increase in interest expense that was partially offset by an increase in other income and a reduction in minority interest in earnings of consolidated subsidiaries.

For the year ended December 31, 2001, interest expense (which includes both corporate and project level interest expense) was $387.7 million, compared to $249.7 million in 2000, an increase of $138.0 million or approximately 55.3%. This increase is due to increased corporate and project level debt issued during 2001. During 2001, we issued substantial amounts of long-term debt at both the corporate level (recourse debt) and project level (non-recourse debt) to either directly finance the acquisition of electric generating facilities or refinance short-term bridge loans incurred to finance such acquisitions.

For the year ended December 31, 2001, minority interest in earnings of consolidated subsidiaries was $1.8 million, compared to $0.8 million, an increase of $1.0 million or approximately 125.0%, as compared to 2000.

For the year ended December 31, 2001, other income, net, was $19.7 million, as compared to $5.8 million for the year ended December 31, 2000, an increase of $13.9 million, or approximately 239.7%. Other income, net, consists primarily of interest income on cash balances and loans to affiliates, and miscellaneous other items, including the income statement impact of certain foreign currency translation adjustments and the impact of gains and losses on the dispositions of investments. Approximately $18.0 million of the increase relates to interest on cash balances and loans to affiliates, primarily West Coast Power. The increase also includes gains on foreign currency translation adjustments and miscellaneous asset sales that were partially offset by a $3.8 million charge to write-off capitalized costs associated with the Estonia project.

Income Tax

For the year ended December 31, 2001, income tax expense was $39.3 million, compared to an income tax expense of $98.4 million for the year ended December 31, 2000, a decrease of $59.1 million. Approximately $14.7 million of the decrease is attributed to additional IRC Section 29 energy credits that were recorded in 2001, as compared to the same period in 2000. We reported a worldwide effective tax rate of approximately 11.4% for the year ended December 31, 2001, compared to approximately 36.5% for the year ended December 31, 2000. The overall reduction in tax rates was primarily due to the increase in energy credits, the implementation of state tax planning strategies and a higher percentage of our overall earnings derived from foreign projects in lower tax jurisdictions.

Discontinued Operations

Discontinued operations consist of projects that were sold in 2001 or were deemed to have met the required criteria for such classification pending final disposition. As of December 31, 2001, discontinued operations consisted of the historical operations and net gains/losses related to our Crockett Cogeneration, Entrade, Killingholme, Csepel, Hsin Yu, Bulo Bulo, McClain, NLGI and TERI projects. As of December 31, 2000, discontinued operations consisted of the historical operations and net gains/losses related to our Crockett Cogeneration, Killingholme, Entrade, and NLGI projects. Income from discontinued operations was $41.4 million in 2001 compared to $33.4 million in 2000. The $8.0 million increase was primarily due to increased earnings from our Entrade project and additional earnings due to Csepel. This increase was offset by losses incurred by McClain.

Liquidity and Capital Resources

Historical Cash Flows

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 have 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.

	Year Ended December 31,			For the Nine Months Ended September 30,	
(Dollars in thousands)	2000	2001	2002	2002	2003
				(Unaudited)	
Net cash provided by operating activities	$ 361,678	$ 276,014	$ 430,043	$ 388,507	$ 121,315
Net cash used in investing activities	(2,204,148)	(4,335,641)	(1,681,467)	(1,652,122)	(160,124)
Net cash provided by financing activities	1,905,870	4,153,546	1,449,330	1,433,974	(24,119)

Net cash provided by operating activities for the nine months ended September 30, 2003 resulted from decreased operating results offset by a decrease in working capital items, as compared to the same period in 2002. The decrease in working capital was due to increased accounts payable. Net cash provided by operating activities increased during 2002 compared with 2001, primarily due to our efforts to conserve cash by deferring the payment of interest and managing our cash flows more closely. Net cash provided by operating activities decreased during 2001 compared with 2000, primarily due to adverse changes to working capital and increased undistributed equity earnings from unconsolidated affiliates. These decreases to net cash were partially offset by increases in net income after non-cash adjustments for depreciation and amortization in 2001 as compared to 2000. The adverse changes to working capital are primarily due to increases in inventory balances, accrued income taxes receivables and changes in other long-term assets and liabilities, partially offset by a favorable change in other current liabilities.

Net cash used by investing activities for the nine months ended September 30, 2003 was positively affected by cash proceeds received upon the sale of equity method investments and reduced capital expenditures as compared to the same period in 2002. Net cash used in investing activities decreased in 2002, compared with 2001, primarily as a result of us terminating our acquisition program due to our financial difficulties and the receipt of cash upon the sale of assets during 2002. Net cash used in investing activities increased in 2001, compared with 2000, primarily due to additional acquisitions of electric generating facilities and increased capital expenditures and project investments.

Net cash used by financing activities increased for the nine months ended September 30, 2003 compared to the same period in 2002. During the nine months ended September 30, 2003, we borrowed less money than during the same period in 2002. Offsetting, we made less principal payments in 2003 as compared to the same period in 2002 due to our deteriorating financial condition. Net cash provided by financing activities during 2002 decreased compared to 2001 due to constraints on our ability to access the capital markets and the cancellation and termination of construction projects reducing the need for capital. Net cash provided by financing activities during 2001 increased compared to 2000 due to the issuance of debt and equity securities to finance asset acquisitions.

Chapter 11 Filings

As described under “The Bankruptcy Case” section of this report, we and certain of our subsidiaries filed voluntary petitions for reorganization relief under chapter 11 of the bankruptcy code. The matters described under this caption “Liquidity and Capital Resources” describe our expectations of the liquidity and capital resources of the company upon emergence from bankruptcy. As such, many of the restrictions on our activities, limitations on financing and obligations to obtain bankruptcy court approval for various matters are assumed to be lifted. We also believe that our relationships with vendors, suppliers, customers and others with whom we may conduct or seek to conduct business will return to normal industry practices for an entity not in chapter 11.

Sources

The principal sources of liquidity for our future operations, capital expenditures, facility closures and project restructurings are expected to be: (i) existing cash on hand and cash flows from operations, (ii) Xcel Energy’s contribution net of distributions to creditors, (iii) proceeds from the sale of certain assets and businesses and (iv) borrowings under our New Credit Facility, including up to $250.0 million of available borrowings under our new revolving credit facility and working capital arrangements as described herein. Additionally, there are approximately $88.8 million of undrawn letters of credit under the pre-petition ANZ LC Facility. The ANZ LC Facility is supported by a claim reserve which will provide the appropriate bankruptcy recovery to the extent these letters of credit are drawn prior to their expiration. There are no current or anticipated drawings on our DIP facility. The DIP facility will expire on effectiveness of the Northeast/ South Central plan of reorganization.

Upon our emergence from bankruptcy, all of our existing securities, including our old common stock and various issuances of senior notes, will be cancelled and approximately $5.2 billion of our existing debt and approximately $1.3 billion of additional claims and disputes will be eliminated for a combination of equity, up to $540.0 million in cash and $500.0 million of Plan Notes. See “The Bankruptcy Case” for a description of these distributions. In addition, upon completion of the Refinancing Transactions, we will, among other things: (i) repay the Northeast Genco Notes, the South Central Notes and the Mid-Atlantic Obligations; (ii) pre-fund a letter of credit subfacility under the New Credit Facility; and (iii) pay fees and expenses related to the Refinancing Transactions.

Cash Flows. Upon emergence from chapter 11, our operating cash flows are expected to be impacted by, among other things: (i) spark spreads generally, (ii) commodity demand, (iii) the cost of ordinary course operations and maintenance expenses, (iv) planned and unplanned outages, (v) contraction of terms by trade creditors, (vi) cash requirements for closure and restructuring of certain facilities, (vii) restrictions in the declaration or payments of dividends or similar distributions from our subsidiaries, and (viii) the timing and nature of asset sales.

A principal component of the NRG plan of reorganization is a settlement with Xcel Energy in which Xcel Energy agreed to make a contribution to us consisting of cash (and, under certain circumstances, its common stock) in an aggregate amount of up to $640.0 million to be paid in three separate installments. Currently, we expect Xcel Energy to contribute $288.0 million 90 days after the confirmation of the plan of reorganization, of which $150.0 million may be paid in common stock of Xcel Energy. We anticipate receiving an additional installment of up to $352.0 million in cash on April 30, 2004. We will distribute $515.0 million of cash we receive from Xcel Energy to our creditors. In the event we achieve certain liquidity measures in September 2004, an additional $25.0 million may be distributed to creditors, and we will use up to $100.0 million to redeem outstanding Plan Notes. In the event no Plan Notes are outstanding at that time, we may use such $100.0 million for any purpose, subject to any restrictions contained in our Financing agreements.

Asset Sales. We received $352.0 million and $288.0 million in net cash proceeds from the sale of certain assets and businesses in the fiscal year ended 2002 and the nine months ended September 30, 2003, respectively. Additionally, since September 30, 2003 we closed transactions providing $88.5 million in net proceeds, most notably from the sale of our Central San Antonio Libertador Gas Turbine Package and Peruvian assets. We anticipate receiving net cash proceeds of approximately $25.0 million if our sale of Loy Yang receives regulatory approval. After consummation of the Refinancing Transactions, our Financing agreements will place restrictions on the use of proceeds we receive from any asset sales.

Letter of Credit Subfacility and Revolving Credit Facility. As described elsewhere in this report, the New Credit Facility includes a letter of credit subfacility in the amount of $250.0 million and a revolving credit facility in the amount of $250.0 million to be used for general corporate purposes. We expect the revolving credit facility to be undrawn at closing of the Refinancing Transactions.

Uses

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

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

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

Capital Expenditure. Capital expenditures were $85.6 million and $1.4 billion during the nine months ended September 30, 2003 and the year ended December 31, 2002. Capital expenditures in 2003 relate primarily to operations and maintenance of our existing generating facilities whereas capital expenditures in 2002 related primarily to new plant construction. We estimate our total 2003 capital expenditures will be approximately $107 million. We anticipate that our 2004 capital expenditures will be approximately $104 million.

Project Finance Requirements. We are a holding company and conduct our operations through subsidiaries. Historically, we have utilized non-recourse debt to fund a significant portion of the capital expenditures and investments required to construct our power plants and related assets. Consistent with our strategy, we may seek, where available on commercially reasonable terms, non-recourse debt financing in connection with the assets or businesses that NRG or its affiliates may develop, construct or acquire. Non-recourse borrowings are substantially non-recourse to other subsidiaries and affiliates and to NRG Energy, Inc. as the parent company, and are generally secured by the capital stock, physical assets, contracts and cash flow of the related project subsidiary or affiliate. Some of these project financings require NRG Energy, Inc. to post collateral in the form of cash or an acceptable letter of credit. At September 30, 2003, on a pro forma basis after giving effect to the completion of the Reorganization Events and the Refinancing Transactions, we had $2.5 billion of recourse debt and $1.8 billion of non-recourse debt outstanding. For more information, see “Description of Certain Indebtedness.”

If we decide not to provide any additional funding or credit support to our subsidiaries, the inability of any of our subsidiaries that are under construction or that have near-term debt payment obligations to obtain non-recourse project financing may result in such subsidiary’s insolvency and the loss of our investment in such subsidiary. Additionally, the loss of a significant customer at any of our subsidiaries may result in the need to restructure the non-recourse project financing at that subsidiary, and the inability to successfully complete a restructuring of the non-recourse project financing may result in a loss of our investment in such subsidiary.

Liquidity Estimates

For 2004, we anticipate utilizing approximately $200.0 million of our $250.0 million letter of credit subfacility. In addition, we believe that approximately $265.0 million to $360.0 million of cash may be required for PMI to meet its potential margin requirements and to cover prepayments and fuel inventory builds. As part of our Refinancing Transactions, we will establish a $250.0 million revolving credit facility. The revolving credit facility is being established to satisfy short term working capital requirements which may arise from time to time. We do not anticipate drawing down on the revolving credit facility upon the closing of the Refinancing Transactions, and it is not our current intention to maintain a positive borrowing balance under the revolving credit facility.

Other Liquidity Matters

We maintain cash deposits in order to assure the continuation of vendor trade terms. As of September 30, 2003, the total amount of cash deposits maintained for these purposes was approximately $85.5 million.

We expect our capital requirements to be met with existing cash balances, cash flows from operations, borrowings under our New Credit Facility and asset sales. We believe that our current level of cash availability and asset sales refinancing, 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 New Credit Facility, if cash generated from operations is insufficient to satisfy our liquidity requirements, we may seek to sell assets, obtain additional credit facilities or other financings and/or issue additional equity or convertible instruments. We cannot assure you, however, that our business will generate sufficient cash flow from operations, that currently anticipated cost savings and operating improvements will be realized on schedule or that future borrowings will be available to us under our credit facilities in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness on or before maturity. We cannot assure you that we will be able to refinance any of our indebtedness on commercially reasonable terms or at all.

Off Balance-Sheet Items

As of September 30, 2003, we do not have any significant relationships with structured finance or special purpose entities that provide liquidity, financing or incremental market risk or credit risk.

We have numerous investments of generally less then 50% interests in energy and energy related entities that are accounted for under the equity method of accounting as disclosed in note 10 to the consolidated financial statements included elsewhere in this report. In the normal course of business we may be asked to loan funds to these entities on both a long and short-term basis. Such transactions are generally accounted for as accounts payables and receivables to/from affiliates and notes receivables from affiliates and if appropriate, bear market-based interest rates. For additional information regarding amounts accounted for as notes receivables to affiliates see note 12 to the consolidated financial statements included elsewhere in this report.

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 Notes 13, 14 and 22 to the consolidated financial statements included elsewhere in this report.

	Payments Due by Period as of September 30, 2003				
Contractual Cash Obligations	**Total**	**Short Term**	**1-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Long-term debt	$8,506,395	$7,843,609	$ 103,821	$ 91,873	$467,092
Capital lease obligations	555,609	29,796	50,061	50,000	425,752
Operating leases	80,556	11,514	21,067	18,030	29,945
Total contractual cash obligations	$9,142,560	$7,884,919	$174,949	$159,903	$922,789

	Amount of Commitment Expiration per Period as of September 30, 2003				
Other Commercial Commitments	**Total Amounts Committed**	**Short Term**	**1-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Lines of credit	$ 1,000,000	$ 1,000,000	—	—	—
Stand by letters of credit	88,773	88,773	—	—	—
Cash collateral calls	1,177,545	1,177,545	—	—	—
Guarantees of Subsidiaries	799,636	37,000	173,557	136,126	452,953
Guarantees of PMI	154,295	63,963	5,000	—	85,332
Total commercial commitments	$3,220,249	$2,367,281	$178,557	$136,126	$538,285

Derivative Instruments

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 September 30, 2003 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at September 30, 2003.

Trading Activity Gains/(Losses)

	September 30, 2003
	(Dollars in thousands)
Fair value of contracts outstanding at December 31, 2002.	$ 30,640
Contracts realized or otherwise settled during the period	(137,955)
Other changes in fair values	12,862
Fair value of contracts outstanding at September 30, 2003	(94,453)
Fair value of contracts outstanding at June 30, 2003	(100,637)
Contracts realized or otherwise settled during the period	(8,450)
Other changes in fair values	14,634
Fair value of contracts outstanding at September 30, 2003	$ (94,453)

Sources of Fair Value Gains/(Losses)

	Fair Value of Contracts at Period End as of September 30, 2003				
	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess of 5 Years	Total Fair Value
	(Dollars in thousands)				
Prices actively quoted	$ (173)	$ 67	$ —	$ —	$ (106)
Prices based on models and other valuation methods	4,360	(2,200)	(7,115)	(89,392)	(94,347)
	$ 4,187	$ (2,133)	$ (7,115)	$ (89,392)	$ (94,453)

We 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.

Quantitative and Qualitative Disclosures About Market Risk

Historically we have used 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.

Currency Exchange Risk

We expect to continue to be subject to currency risks associated with foreign denominated distributions from our international investments. In the normal course of business, we may receive distributions denominated in the Australian Dollar, British Pound, Euro and the Brazilian Real. We have historically engaged in a strategy of hedging foreign denominated cash flows through a program of matching currency inflows and outflows, and to the extent required, fixing the U.S. Dollar equivalent of net foreign denominated distributions with currency forward and swap agreements with highly credit worthy financial institutions. We would expect to enter into similar transactions in the future if management believes it to be appropriate.

As of September 31, 2003, we had one foreign currency denominated debt instrument outstanding in the amount of £160 million due 2020 which has historically subjected us to the impact of fluctuations in the foreign currency markets. Upon emergence from bankruptcy this debt instrument will be settled and we will no longer be subject to the impact of such market fluctuations related to this debt instrument.

As of September 30, 2003, we did not have any outstanding foreign currency exchange contracts.

Interest Rate Risk

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

As of September 30, 2003, we had various interest rate swap agreements with notional amounts totaling approximately $765.5 million. If the swaps had been discontinued on September 30, 2003, we would have owed the counter parties approximately $75.0 million. Based on the investment grade rating of the counter parties, we believe that our exposure to credit risk due to nonperformance by the counter-parties to our hedging contracts is insignificant.

We have both long and short-term debt instruments that subject us to the risk of loss associated with movements in market interest rates. On a pro forma basis giving effect to our emergence from bankruptcy and the completion of the Transactions, as of September 30, 2003, a 100 basis point change in the benchmark rate on our variable rate debt would impact net income by approximately $16.1 million.

Commodity Price Risk

We are exposed to commodity price variability in electricity, emission allowances and natural gas, oil and coal used to meet fuel requirements. To manage earnings volatility associated with these commodity price risks, we enter into financial instruments, which may take the form of fixed price, floating price or indexed sales or purchases, and options, such as puts, calls, basis transactions and swaps.

We utilize an undiversified “Value-at-Risk” (VAR) model to estimate a maximum potential loss in the fair value of our commodity portfolio including generation assets, load obligations and bilateral physical and financial transactions. The key assumptions for our VAR model include (1) a lognormal distribution of price returns (2) three day holding period and (3) a 95% confidence interval. The volatility estimate is based on the implied volatility for at the money call options. This model encompasses the following generating regions: Entergy, NEPOOL, NYPP, PJM, WSCC, SPP and Main.

The estimated maximum potential three-day loss in fair value of our commodity portfolio, calculated using the VAR model is as follows:

	(Dollars in millions)
Nine-month period ended September 30, 2003.	$ 124.6
Average	153.5
High	181.5
Low	124.6
Year end December 31, 2002	118.6
Average	76.2
High	124.4
Low	42.0
Year end December 31, 2001	71.7
Average	78.8
High	126.6
Low	58.6
Year end December 31, 2000	116.0
Average	80.0
High	125.0
Low	50.0

PMI has risk management policies in place to measure and limit market and credit risk associated with our power marketing activities. These policies do not permit speculative or directional trading. An independent department within PMI is responsible for the enforcement of such policies. We are currently in the process of reviewing and revising these policies to reflect changes in best practices and industry dynamics.

Credit Risk

We are exposed to credit risk in our risk management activities. Credit risk relates to the risk of loss resulting from the nonperformance by a counter party of its contractual obligations. We actively manage our counter-party credit risk. We have an established credit policy in place to minimize overall credit risk. Important elements of this policy include ongoing financial reviews of all counter-parties, established credit limits, as well as monitoring, managing and mitigating credit exposure.

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 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. In addition, the financial and operating environment may have a significant effect, not only on the operation of the business, but on the results reported though 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 particular circumstances. 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.

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.

Discontinued Operations

We classify our long-lived assets (disposal group) to be sold as held for sale in the period in which the following criteria are met:

- management approves the action and commits to a plan to sell the asset. This is generally evidenced by the signing of an asset sales agreement, board of directors approval and, prior to emergence from chapter 11, creditor committee approval and bankruptcy court approval;

- the long-lived asset (disposal group) is generally deemed to be available for immediate sale and our condition is subject only to the terms and conditions customary for the sale of such assets;

- management has actively engaged in a program to locate a buyer and has initiated other such actions required to complete the plan to sell the asset;

- the sale is probable and transfer of the asset is expected to be completed with one year;

- the asset is being marketed at a price that is believed to be reasonable in relation to our current fair value; and

- management believes that it is unlikely that significant changes to the plan to sell that asset will be made or that the plan will be withdrawn.

Capitalization Practices and Purchase Accounting

As of September 30, 2003, we had a carrying value of approximately $6.1 billion of net property, plant and equipment, $461.0 million of which is under construction or turbines being marketed, representing approximately 59.5% and 4.5% of total assets, respectively. The majority of the carrying value of property, plant and equipment is the result of our recent asset acquisitions and constructions. These amounts represent the estimated fair values at the date of acquisition and construction.

For those assets that were or are 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 which are incurred incidental to a particular project. Such costs are expensed as incurred until an acquisition agreement or letter of intent is signed, and the project has been approved by our board of directors. Additional costs incurred after this point are capitalized. When a project begins operation, previously capitalized project costs are reclassified to equity investments in affiliates or property plant and equipment and amortized on a straight-line basis over the lesser of the life of the project's related assets or revenue contract period.

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. As of September 30, 2003, net income from continuing operations was reduced by $229.6 million due to impairments recorded in 2003. Asset impairment evaluations are by nature highly subjective. The carrying value of assets on our balance sheet should not be viewed as an indication of the price that those assets might sell for in a liquidation.

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 and collect methane gas from landfill sites, which is then used for the generation of electricity. Both physical and financial transactions are entered into to optimize the financial performance of our generating facilities. Electric energy is recognized upon transmission to the customer. Capacity and ancillary revenue is recognized when contractually earned. Revenues from operations and maintenance services is recognized when the services are performed. We use the equity method of accounting to recognize our pro rata share of the net income or loss of our unconsolidated investments. We continually assesses 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," as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149. FAS No. 133 requires us to record all derivatives on the balance sheet at fair value. 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 (OCI) until the hedged transactions occur and are recognized in earnings. We primarily apply FAS No. 133 to 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. FAS No. 133 also applies to interest rate swaps and foreign currency exchange rate contracts. The application of SFAS No. 133 results in increased volatility in earnings due to the impact market prices have on the market positions and financial instruments that we have entered into. 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.

Estimates

On an ongoing basis, we evaluate our estimates, utilizing historical data, consultation with experts and other methods we deem reasonable on a case by case basis. 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 revisions become known.

Recent Accounting Developments

In April 2002, the FASB issued SFAS No. 145, “Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections”, that supersedes previous guidance for the reporting of gains and losses from extinguishment of debt and accounting for leases, among other things.

SFAS No. 145 requires that only gains and losses from the extinguishment of debt that meet the requirements for classification as “Extraordinary Items,” as prescribed in Accounting Practices Board Opinion No. 30, should be disclosed as such in the financial statements. Previous guidance required all gains and losses from the extinguishment of debt to be classified as “Extraordinary Items.” This portion of SFAS No. 145 is effective for fiscal years beginning after May 15, 2002, with restatement of prior periods required.

In addition, SFAS No. 145 amends SFAS No. 13, “Accounting for Leases,” as it relates to accounting by a lessee for certain lease modifications. Under SFAS No. 13, if a capital lease is modified in such a way that the change gives rise to a new agreement classified as an operating lease, the assets and obligation are removed, a gain or loss is recognized and the new lease is accounted for as an operating lease. Under SFAS No. 145, capital leases that are modified so the resulting lease agreement is classified as an operating lease are to be accounted for under the sale-leaseback provisions of SFAS No. 98, “Accounting for Leases.” These provisions of SFAS No. 145 are effective for transactions occurring after May 15, 2002.

SFAS No. 145 will be applied as required. Adoption of SFAS No. 145 is not expected to have a material impact on us.

In June 2002, the FASB issued SFAS No. 146, “Accounting for Costs Associated with Exit or Disposal Activities,” (SFAS No. 146). SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, “Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).” SFAS No. 146 applies to costs associated with an exit activity that does not involve an entity newly acquired in a business combination or with a disposal activity covered by SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets.” The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. SFAS No. 146 will be applied as required.

In January 2003, the FASB issued FASB Interpretation No. 46, Consolidation of Variable Interest Entities (FIN No. 46). FIN No. 46 requires an enterprise’s consolidated financial statements to include subsidiaries in which the enterprise has a controlling interest. Historically, that requirement has been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise’s consolidated financial statements do not include the consolidation of variable interest entities with which it has similar relationships but no majority voting interest. Under FIN No. 46 the voting interest approach is not effective in identifying controlling financial interest. The new rule requires that for entities to be consolidated that those assets be initially recorded at their carrying amounts at the date the requirements of the new rule first apply. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value the first date the new rule applies. Any difference between the net amount of any previously recognized interest in the newly consolidated entity should be recognized as the cumulative effect of an accounting change. FIN No. 46 becomes effective in the first interim or annual period ending after December 15, 2003. FIN No. 46 will be applied as required and is not expected to have a material impact on us.

In April 2003, the FASB issued SFAS No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities,” or SFAS No. 149.” SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. The provisions of SFAS No. 149 are effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2002. In addition, provisions of SFAS 149 that relate to SFAS Statement No. 133 Implementation Issues that have been effective for fiscal quarters that began prior to June 15, 2003, should continue to be applied in accordance with their respective effective dates. SFAS No. 149 will be applied as required and is not expected to have a material impact on us.

In May 2003, the FASB issues SFAS No. 150, “Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity,” or “SFAS No. 150.” SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. The provisions of SFAS 150 are effective for financial instruments entered into or modified after May 31, 2003, and otherwise are effective at the beginning of the first interim period beginning after June 15, 2003. SFAS No. 150 is not expected to have an impact on us.

Controls and Procedures

During the fourth quarter of 2002, our officers determined that there were certain deficiencies or “reportable conditions” in the internal controls relating to financial reporting at NRG caused by our pending financial restructuring and business realignment. During the second half of 2002, there were material changes and vacancies in our senior management positions and a diversion of our financial and management resources to restructuring efforts. These circumstances detracted from our ability through our internal controls to timely monitor and accurately assess the impact of certain transactions, as would be expected in an effective financial reporting control environment. During 2003 we have dedicated significant resources to make corrections to those control deficiencies, including hiring several key senior and middle management positions, hiring an outside consultant to review, document and suggest improvements to controls, and the implementation of new controls and procedures. We will continue to dedicate resources to this effort over the next few months. In addition, on October 21, 2003, we announced the appointment of David W. Crane as our new President and Chief Executive Officer, effective December 1, 2003. We are currently conducting a search for a new Chief Financial Officer and anticipate the position will be filled in the months following our emergence from bankruptcy.

Our officers are primarily responsible for the accuracy of the financial information that is represented in this report. To meet their responsibility for financial reporting, they have established internal controls and procedures which, subject to the disclosure in the foregoing paragraph, they believe are adequate to provide reasonable assurance that our assets are protected from loss. There were no significant changes in internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

In 1997, 1998, 1999 and 2002, we amended our annual reports on Form 10-K to provide required financial information for significant subsidiaries for which financial information was unavailable at the time we filed our respective Form 10-K’s. In addition, on or about December 8, 2003, we will amend our quarterly report on Form 10-Q to reflect a reclassification of certain expenses.

BUSINESS

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 helps us mitigate risk. We intend to maximize operating income through the efficient procurement and management of fuel supplies and maintenance services, and the sale of energy, capacity and ancillary services into attractive spot, intermediate and long-term markets. On a pro forma basis after giving effect to the Reorganization Events and the Refinancing Transactions (each as defined hereafter), we generated total operating revenues and equity earnings of approximately $2.3 billion and Pro Forma Adjusted EBITDA of approximately $549.7 million for the twelve-month period ending September 30, 2003.

As of September 30, 2003, we owned interests in 86 power projects in eight countries having an aggregate generation capacity of approximately 18,300 MW. Approximately 8,300 MW of our capacity consists of merchant power plants in the Eastern region of the United States. Certain of these assets are located in transmission constrained areas, including approximately 1,400 MW of “in-city” New York City generation capacity and approximately 700 MW of southwest Connecticut generation capacity. We also own approximately 5,600 MW of capacity in the Central region of the United States, with approximately 3,000 MW of that capacity supported by long-term power purchase agreements. Our assets in the Western region of the United States consist of approximately 1,300 MW of capacity with the majority of such capacity owned via our 50% interest in West Coast Power. Our assets in the Western region are supported by a power purchase agreement with the California Department of Water Resources that runs through December 2004. As of September 30, 2003, our principal domestic generation assets consisted of a diversified mix of natural gas-, coal- and oil-fired facilities, representing approximately 48%, 26% and 26% of our total domestic generation capacity, respectively. We also own interests in plants having a generation capacity of approximately 3,100 MW in various international markets, including Australia, Europe and Latin America. Our energy marketing subsidiary PMI began operations in 1998 and is focused on maximizing the value of our North American assets by providing centralized contract origination and management services, and through the efficient procurement and management of fuel and the sale of energy and related products in the spot, intermediate and long-term markets.

Strategy

We own and operate a diverse portfolio of electric generation facilities which we believe have strategic locational advantages. Through our reorganization, we intend to reposition ourselves in our industry to focus on owning, operating and maximizing the value of our generation assets. We are implementing this strategy through the following key actions:

- optimizing the value of our existing assets with a focus on operational reliability and efficiency;
- retaining a new management team with proven industry experience;
- mitigating risk by pursuing asset-focused power marketing activities through effective procurement of fuel and fuel services and the sale of energy and related products into spot, intermediate and long-term markets;

- improving our liquidity position and further deleveraging our balance sheet; and
- limiting acquisitions and new project developments in the near term.

Competitive Strengths

We believe that we benefit from the following competitive strengths:

Plant Diversity. Our generation fleet in each regional market includes base-load, intermediate and peaking facilities to maximize our profit opportunities along the entire energy dispatch curve. Our generation facilities are likewise diversified by fuel-type, including coal, oil and natural gas. The diversity of technology, fuel type and operational characteristics allows us to participate in all aspects of the electricity demand cycle. By offering what we believe to be an efficient mix of generation, we are able to offer competitive prices to our customers and optimize the revenue potential across the entire fleet. For example, due to the recent volatility and price spikes of natural gas, our coal assets, such as Huntley, Dunkirk, Big Cajun II and Indian River, have a distinct competitive advantage due to the relatively low marginal cost of coal. Peaker assets provide increased revenue by taking advantage of higher prices in periods of increased demand in the energy markets. Further, peaking and intermediate assets can provide emergency back-up when our base-load plants experience outages.

Regional Strength. We believe we have acquired a number of power plants in the Eastern, Central and Western regions of the United States, providing economies of scale throughout the organization, and reducing our dependence on any single market. Owning multiple plants in a particular market provides us greater dispatch flexibility and increases power marketing opportunities.

Locational Advantages. We own and operate many facilities which are strategically located near large urban areas or in certain transmission-constrained areas with locational advantages over our competition. For example, the Astoria and Arthur Kill plants are ideally situated to serve the New York City market. Due to transmission constraints, competitors outside the city limits are restricted from importing power into New York City, and therefore do not have the advantage of “in city” generation. Certain facilities in California near the Los Angeles and San Diego load centers use ocean water cooling that gives them competitive advantages, especially during water shortages. Additionally, construction of new power plants in areas such as New York City and California is limited because of the difficulty in:

- finding sites for new plants;
- overcoming the general public’s “not-in-my-backyard” mentality;
- obtaining the necessary permits; and
- arranging fuel supplies.

In some locations, a facility’s advantage is also enhanced by the potential for re-powering or site expansion.

Risk Mitigation. As a wholesale generator, we are subject to the risks associated with volatility in fuel and power prices. We mitigate these risks by managing a portfolio of contractual assets for both power supply and fuel requirements. In the near term our portfolio will be weighted toward spot market sales and short-term contracts because long-term contracts are not currently available at attractive prices. We expect that these generally weak market conditions will continue for the foreseeable future in some markets. As the markets improve, we will seek opportunities to enter into longer-term agreements in order to capture more stable returns and predictable cash flow. We manage counterparty credit risk by monitoring credit ratings and when necessary by requiring appropriate credit support in the form of cash collateral or letters of credit.

Improved Financial Position. As part of our plan of reorganization, we are eliminating 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, up to $540.0 million in cash and $500.0 million of new debt among our unsecured creditors. Since the implementation of our divestiture program in July 2002, we have successfully sold certain assets, eliminating approximately $1.2 billion of debt.

Power Generation

Eastern Region

Facilities. As of September 30, 2003, we owned approximately 8,300 MW of net generating capacity (including projects under construction) in the Eastern United States. Of that amount, approximately 6,900 MW consist of net generating capacity in the Northeast United States, primarily in New York, Connecticut and Massachusetts. These generation facilities are diversified in terms of dispatch level (base-load, intermediate and peaking), fuel type (coal, natural gas and oil) and customers. Approximately 1,400 MW consist of net generating capacity in the mid-Atlantic region and southeastern United States.

The Eastern Region power generation assets as of September 30, 2003 are summarized in the table below.

Name and Location of Facility	Purchaser/ Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
Oswego, New York	Niagara Mohawk/NYISO	1,700	100%	Oil/Gas
Huntley, New York	Niagara Mohawk/NYISO	760	100%	Coal
Dunkirk, New York	Niagara Mohawk/NYISO	600	100%	Coal
Arthur Kill, New York	NYISO	842	100%	Gas/Oil
Astoria Gas Turbines, New York	NYISO	600	100%	Gas/Oil
Ilion, New York*	NYISO	60	100%	Gas/Oil
Somerset, Massachusetts	Eastern Utilities Associates	136	100%	Coal/Oil/Jet
Middletown, Connecticut	ISO-NE	786	100%	Oil/Gas/Jet/Diesel
Montville, Connecticut	ISO-NE	498	100%	Oil/Gas/Jet/Diesel
Devon, Connecticut	ISO-NE	401	100%	Gas/Oil/Jet
Norwalk Harbor, Connecticut	ISO-NE	353	100%	Oil
Connecticut Jet Power, Connecticut	ISO-NE	127	100%	Jet
Other — 2 projects*	Various	14	Various	Various
Indian River, Delaware	Delmarva/PJM	784	100%	Coal/Oil
Vienna, Maryland	Delmarva/PJM	170	100%	Oil
Conemaugh, Pennsylvania	PJM	64	4%	Coal/Oil
Keystone, Pennsylvania	PJM	63	4%	Coal/Oil
Dover, Delaware	PJM	106	100%	Gas/Coal
Paxton Creek Cogeneration, Pennsylvania	Virginia Electric & Power	12	100%	Gas
Commonwealth Atlantic, Virginia*	Virginia Electric & Power	188	50%	Gas/Oil
James River, Virginia*	Virginia Electric & Power	55	50%	Coal

* May sell or dispose of in the next 12 months.

Market Framework. Our largest asset base is located in the Eastern region. This region is comprised of investments in generation facilities located in the physical control areas of NYISO, the ISO New England, Inc., or "ISO-NE," and the Pennsylvania, Jersey, Maryland Interconnection, or "PJM." In addition, a number of our Eastern region assets are located outside of the ISO administered marketplaces of the Northeast, within the regional utilities operating in the Southeastern United States.

Although each of the three northeast ISOs are functionally, administratively and operationally independent from one another, they all tend to follow, to a certain extent, the FERC endorsed model for

Standard Market Design, or “SMD.” The physical power deliveries in these markets are financially settled by Locational Marginal Prices, or “LMPs,” which reflect the value of energy at a specific location at the specific time it is delivered. This value is determined by an ISO administered auction process, which evaluates and selects the least cost of supplier offers or ‘bids’ to fill the specific locational requirement. The ISO sponsored LMP energy marketplaces consist of two separate and characteristically distinct settlement time frames. The first is a security constrained, financially firm, “Day Ahead” unit commitment, or “DAM.” The second is a financially settled, security constrained “Real Time” dispatch and balancing market, or “RT.” In addition to energy delivery, the ISOs manage secondary markets for installed capacity, ancillary services and financial transmission rights.

Market Developments. On March 1, 2003, ISO-NE implemented its version of SMD. This change dramatically modified the New England market structure by incorporating Locational Marginal Pricing, or “LMP,” which means pricing by location rather than on a New England wide basis. Even though we view this change as a significant improvement to the existing market design, we still view the market within New England as incapable of allowing us to recover our costs and earn a reasonable return on our investment.

On February 26, 2003, we filed a proposed cost of service agreement with FERC for the following Connecticut facilities: Devon station, units 11-14, Middletown station, Montville station and Norwalk station (FERC Docket No ER03-563-000). In response, on March 25, 2003, FERC issued an order, the “March 25, 2003 Order,” approving a tracking mechanism for the payment of or recovery of certain maintenance expenses, subject to refund, and authorized an effective date of February 27, 2003. In the March 25, 2003 Order, FERC also permitted ISO-NE, via an escrow account, to start collecting the maintenance expenses from all NEPOOL participants in order to ensure the availability of our units. In its March 25, 2003 Order, FERC did not rule on the remainder of the issues to allow further time to consider protests it received related to the filing.

On April 25, 2003, FERC issued an order rejecting the remaining part of the proposed cost of service agreements including the monthly cost-based payment, citing certain policy determinations regarding cost of service agreements. Rather, FERC instructed ISO-NE to establish temporary bidding rules that would permit selected units (units with capacity factors of ten percent or less during 2002), operating within designated congestion areas, such as Connecticut, to raise their bids to allow them the opportunity to recover their fixed and variable costs through the market. In May 2003 and June 2003, the ISO-NE revised its market rules to facilitate “peaking unit safe harbor” bidding, or “PUSH” bidding, but has yet to formally propose the market modifications required to implement a locational capacity mechanism. On July 24, 2003, FERC clarified that the capacity factor of ten percent or less applies to units rather than stations. Therefore, on a unit basis, all of our facilities qualify to bid under the temporary rules, except Middletown 2 and 3. The PUSH bidding rule will remain in place until ISO-NE implements locational installed capacity payments, which FERC mandated ISO-NE implement no later than June 1, 2004. ISO-NE indicated in its September 22, 2003 compliance filing with FERC, however, that there may be a delay in the implementation of locational installed capacity pricing.

Consistent with our expectations, PUSH bidding has not yielded sufficient revenues to cover all our costs for most of our affected facilities. We intend to take additional actions with FERC and other Connecticut parties to attempt to address the expected revenue deficiency. In the meantime, ISO-NE continues to make progress in the implementation of locational capacity markets in New England. The exact design of the locational capacity market is not known at this time, and it is difficult to quantify the value of this change.

In addition to the facilities noted above, the following of our quick-start facilities in Connecticut have submitted PUSH bids that have been approved by FERC: Cos Cob, Franklin Drive, Branford, and Torrington. The existing reliability must run agreement between ISO-NE and us covering Devon station units 7 and 8 terminated on September 30, 2003. On October 2, 2003, we filed with FERC to extend the existing reliability must run agreement. FERC has yet to act on the request to extend.

In April of 2003, the NYISO implemented a demand curve in its capacity market and scarcity pricing improvements in its energy market. The New York demand curve eliminated the previous market structure’s tendency to price capacity at either its cap (deficiency rate) or near zero. This change not only improved our

New York financial results, it reduced the risk of our capacity revenues dropping precipitously with little notice. The NYISO scarcity pricing improvements have re-introduced some volatility in the New York energy markets when supplies are short. Both changes have improved our financial performance and increased the value of New York's futures markets.

The NYISO intends to introduce additional changes to its energy market in early 2004, with the implementation of Standard Market Design 2. Although the exact nature of these changes are not known at this time, we anticipate the changes to be small, targeted improvements to the NYISO's present market.

In PJM, we are closely following market power mitigation modifications that may significantly impact the revenues achievable in that market by modifying PJM's price capping mechanisms. On April 2, 2003, Reliant Resources, Inc. filed a complaint against PJM with FERC and suggested specific modifications to PJM's price mitigation rules. On June 9, 2003, FERC rejected the Reliant modifications but required PJM to file a report to address the concerns of Reliant by September 30, 2003. The PJM market monitoring unit filed its compliance filing with FERC as required, but opted to continue its present mitigation practices. The present mitigation plan permits PJM to "cost-cap" the energy bids of certain generating facilities that were constructed prior to 1996. The cost capping method is based on a facility's variable costs plus ten percent. In addition, the PJM market monitoring unit filed to eliminate the exemption that units built after 1996 had from PJM's mitigation measures. This change, if approved by FERC, will impact specific NRG facilities within PJM. It will also continue a practice that has depressed prices in PJM. The PJM market monitoring unit's actions were not endorsed by the requisite number of market participants. It is unclear at this time, what actions FERC will take and how this will impact us.

Central Region

Facilities. As of September 30, 2003, we owned approximately 5,600 MW of net generating capacity (including projects under construction) in the Central United States, primarily in Louisiana, Illinois, Mississippi and Oklahoma. The Central region generating assets consist primarily of our net ownership of power generation facilities in New Roads, Louisiana, or the "Cajun Facilities," and our net ownership of power generation facilities in Kendall and Rockford, Illinois. The central region also includes the Sterlington, McClain, Bayou Cove, Batesville and Rocky Road generating facilities.

Our portfolio of plants in Louisiana and Mississippi comprise the second largest generator in the Southeastern Electric Reliability Council/ Entergy region. The core of these assets are the Cajun Facilities which are primarily coal-fired assets supported by long-term power purchase agreements with regional cooperatives.

The Central region power generation assets as of September 30, 2003 are summarized in the table below.

Name and Location of Facility	Purchaser/ Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
Big Cajun II, Louisiana	Cooperatives/SERC-Entergy	1,489	100%	Coal
Big Cajun I, Louisiana	Cooperatives/SERC-Entergy	458	100%	Gas/Oil
Bayou Cove, Louisiana	SERC-Entergy	320	100%	Gas
Sterlington, Louisiana	Louisiana Generating	202	100%	Gas
Batesville, Mississippi	Aquila/SERC-TVA	837	100%	Gas
McClain, Oklahoma*	SPP-Southern	400	77%	Gas
Kendall, Illinois	Dynegy, Rainy River	1,168	100%	Gas
Rockford I, Illinois	Commonwealth Edison	342	100%	Gas
Rockford II, Illinois	MAIN	171	100%	Gas
Rocky Road Power, Illinois	MAIN	175	50%	Gas
Other — 2 projects*	Various	19	Various	Various

* May sell or dispose of in the next 12 months.

Market Framework. Our Central region assets are located within the control areas of the local, regulated, and sometimes vertically integrated, utilities, primarily Entergy Corporation, or "Entergy," Commonwealth Edison Company, or "ComEd." These utilities perform the scheduling, reserve and reliability functions that are administered by the ISOs in certain other regions of the United States and Canada. We operate a NERC certified control area within the Entergy control area, which is comprised of our generating assets and our co-op customer loads. Although the reliability functions performed are essentially the same, the primary differences between these markets lie principally in the physical delivery and price discovery mechanisms. In the Central region, all power sales and purchases are consummated bilaterally between individual counter-parties, and physically delivered either within or across the physical control areas of the transmission owners from the source generator to the sink load. Transacting counter-parties are required to reserve and purchase transmission services from the intervening transmission owners at their FERC approved tariff rates. Included with these transmission services are the reserve and ancillary costs. Energy prices in the Central regions are determined and agreed to in bilateral negotiations between representatives of the transacting counter-parties, using market information gleaned by the individual marketing agents arranging the transactions.

Market Developments. In the Midwest, it is anticipated that Exelon Corporation will be partially integrated into PJM by the second quarter of 2004, and will transition to PJM's LMP market model soon thereafter. Exelon is the parent corporation of PECO Energy Company and ComEd. On November 25, 2003, FERC issued an order requiring American Electric Power, or "AEP," to join PJM. In the order the FERC stated that AEP must comply with its prior commitment to join an RTO, namely PJM. Previously, the actions taken by the Virginia legislature had restricted AEP's ability to join PJM. At this time the effect of the November 25, 2003 order is unclear. Consequently, Exelon, and our Chicago area assets, could be somewhat isolated from the rest of PJM. The impact of the Exelon integration on us is unclear at this time.

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

In the Southeast, Entergy Corporation and Southern Company, continue to support their regional transmission organization, or "RTO," initiative, SeTrans. The future of SeTrans is uncertain at this time. The Southern Company, Entergy Corporation and the other sponsors of SeTrans have moved forward in developing critical governing documents for this proposed RTO. SeTrans has selected ESBI of Ireland to be their independent system administrator. We view changes that surrender control of the southern transmission grid away from vertically integrated utilities and to an independent entity as positive for wholesale power generators such as us. However, it is unclear at this time how these changes will impact us and when they may occur.

West Region

Facilities. As of September 30, 2003, we owned approximately 1,300 MW of net generating capacity on the West Coast of the United States, primarily California and Nevada. Our west coast generation assets consist primarily of a 50% interest in West Coast Power LLC, or "West Coast Power."

In May 1999, Dynegy and NRG Energy formed West Coast Power to serve as the holding company for a portfolio of operating companies that own generation assets in Southern California in the California Independent System Operator, or "Cal ISO," market. This portfolio currently consists of the El Segundo Generating Station, the Long Beach Generating Station, the Encina Generating Station and 13 combustion turbines in the San Diego area. Dynegy provides power marketing and fuel procurement services to West Coast Power, and we provide operations and management services. An application for a permit to repower the existing El Segundo site, replacing the retired unit 1 & 2 with 600 MW of new generation has been filed.

The permit is in the California Energy Commission review process, and it is anticipated that the approval will be received during the first quarter of 2004.

The Western region power generation assets as of September 30, 2003 are summarized in the table below.

Name and Location of Facility	Purchaser/ Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
El Segundo Power, California	California DWR/Cal ISO	335	50%	Gas
Encina, California	California DWR/Cal ISO	483	50%	Gas/Oil
Long Beach Generating, California	California DWR/Cal ISO	265	50%	Gas
San Diego Combustion Turbines, California	Cal ISO	93	50%	Gas/Oil
Saguaro Power Co., Nevada*	Nevada Power	53	50%	Gas/Oil
Chowchilla, California	Cal ISO	48	100%	Gas
Red Bluff, California	Cal ISO	45	100%	Gas

* May sell or dispose of in the next 12 months.

Market Framework. Our Western region assets are located within the control area of the Cal ISO. The Cal ISO operates a financially settled "Real Time" balancing market, similar to the regional ISO's of the northeast. "Day Ahead" markets in the west are currently similar to those in the Central region with all power sales and purchases consummated bilaterally between individual counter-parties and scheduled for physical delivery with the Cal ISO.

Market Developments. In California, the Cal ISO continues with its plan to move toward markets similar to PJM, NYISO and ISO-NE with its MDO2 initiative (market design 2002). Phase 1B of these changes is currently scheduled to be implemented by March of 2004. These changes will re-establish a real time market and allow for multiple settlements. We view this as an improvement to the existing structure. In general, the Cal ISO is continuing along a path of small incremental changes, rather than significant market restructuring. Although numerous stakeholder meetings have been held, the final market design remains unknown at this time. The effect of the MDO2 changes on us cannot be determined at this time.

In addition to the Cal ISO's market changes, numerous legislative initiatives in California create uncertainty and risk for us. Most significantly, SB39XX mandates that the California Public Utilities Commission, or "CPUC," exercise jurisdiction over the maintenance procedures of wholesale power generators. This effort has slowed in recent months, and it is unclear at this time where that process will lead. The CPUC recently issued draft orders directing the utilities to meet a 17% reserve requirement by no later than the beginning of 2005 and establishing a requirement that utilities acquire 90% of their capacity needs a year in advance. While the orders are not final, they will present significant opportunities to enter into new bilateral agreements.

International

Facilities. Historically, the majority of power generating capacity outside of the United States has been owned and controlled by governments. During the past decade, however, many foreign governments moved to privatize power generation plant ownership through sales to third parties and by encouraging new capacity development and refurbishment of existing assets by independent power developers.

Over the past decade we, through our foreign subsidiaries, invested in international power generation projects in Asia Pacific, Europe and Latin America. During 2002, we sold international generation projects with an aggregate total generating capacity of approximately 600 MW. As of September 30, 2003, we, through certain foreign subsidiaries, had investments in power generation projects located in Australia, the UK, Germany, South America and Taiwan with approximately 3,100 MW of generating capacity.

Our international power generation assets as of September 30, 2003 are summarized in the table below.

Name and Location of Facility	Purchaser/ Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
Asia-Pacific:				
Hsin Yu, Taiwan*	Industrials	107	63%	Gas
Australia:				
Flinders, South Australia	South Australian Pool	760	100%	Coal
Gladstone Power Station, Queensland	Enertrade/Boyne Smelters	630	38%	Coal
Loy Yang Power A, Victoria**	Victorian Pool	507	25%	Coal
Europe:				
Enfield Energy Centre, UK*	UK Electricity Grid	95	25%	Gas/Oil
Schkopau Power Station, Germany	VEAG/Industrials	400	42%	Coal
MIBRAG mbH, Germany***	ENVIA/MIBRAG Mines	119	50%	Coal
Latin America:				
Itiquira Energetica, Brazil*	COPEL/Tradener	154	99%*****	Hydro
COBEE, Bolivia*	Electropaz/ELFEO	219	100%	Hydro/Gas
Energia Pacasmayo, Peru****	Electroperu/Peruvian Grid	66	100%	Hydro/Oil
Cahua, Peru****	Quimpac/Industrials	48	100%	Hydro

* May sell or dispose of in the next 12 months.

** May sell or significantly restructure in the next 12 months.

*** Primarily a coal mining facility.

**** Assets sold on November 21, 2003.

***** Common equity ownership interest.

Alternative Energy

In addition to our traditional power generation facilities discussed above, we own alternative energy generation facilities through NEO Corporation, or "NEO," and through our NRG Resource Recovery business division, which processes municipal solid waste as fuel to generate power.

NEO Corporation. NEO is a wholly owned subsidiary of ours that was formed to develop power generation facilities ranging in size from 1 to 50 MW in the United States. As of September 30, 2003, NEO owned and operated 12 landfill gas collection systems and had 17 MW of net ownership interests in related electric generation facilities utilizing landfill gas as fuel. NEO also had 42 MW of net ownership interests in 17 hydroelectric facilities and 108 MW of net ownership interests in six distributed generation facilities including 93 MW of gas-fired peaking engines in California (referred to as the Red Bluff and Chowchilla facilities and included in our summary of the West region). Certain of the assets owned by NEO are currently being held for sale. See "Significant Dispositions of Non-Strategic Assets" for more information.

NEO's power generation assets as of September 30, 2003 are summarized in the table below.

Name and Location of Facility	Purchaser/ Power Market	Net Owned Capacity (MW)	NRG's Percentage Ownership Interest	Fuel Type
NEO Corporation, Various*	Various	104	Varies	Various

* May sell or dispose of in the next 12 months. Does not include our Chowchilla or Red Bluff facilities.

Resource Recovery Facilities. Our Resource Recovery business is focused on owning and operating alternative fuel/“green power” generation and fuels processing projects. The alternative fuels currently processed and combusted are municipal solid waste, urban wood waste (pallets, clean construction debris, etc.), and non-recyclable waste paper and compost. Our Resource Recovery business has municipal solid waste processing capacity of approximately 3,600 tons per day and generation capacity of 35 MW, of which our net ownership interest is 18 MW. Our Resource Recovery business owns and operates municipal solid waste processing and/or generation facilities in Maine and Minnesota. Resource Recovery also owns and operates NRG Processing Solutions that includes thirteen composting and biomass fuel processing sites in Minnesota, of which three sites are permitted to operate as municipal solid waste transfer stations.

Our significant resource recovery assets as of September 30, 2003 are summarized in the table below.

Name and Location of Facility	Thermal Energy Purchaser/MSW Supplier	Net Owned Capacity	NRG’s Percentage Ownership Interest	Fuel Type
Newport, MN(1)	Ramsey and Washington Counties	MSW: 1,500 tons/day	100%	Refuse Derived Fuel
Elk River, MN(2)	Anoka, Hennepin and Sherburne Counties; Tri-County Solid Waste Management Commission	MSW: 1,500 tons/day	85%	Refuse Derived Fuel
Penobscot Energy Recovery, ME*	Bangor Hydroelectric Company	MSW: 590 tons/day	50%	Refuse Derived Fuel

* May sell or dispose of in the next 12 months.

(1) The Newport facilities are related strictly to municipal solid waste processing facilities.

(2) For the Elk River facility, NRG’s 85% interest is related strictly to municipal solid waste processing facilities.

Thermal and Chilled Water Businesses. We have interests in district heating and cooling systems and steam transmission operations through our subsidiary NRG Thermal LLC. NRG Thermal’s thermal and chilled water businesses have a steam and chilled water capacity of approximately 1,290 megawatt thermal equivalents, or “MWt.”

As of September 30, 2003, NRG Thermal owned five district heating and cooling systems in Minneapolis, Minnesota; San Francisco, California; Pittsburgh, Pennsylvania; Harrisburg, Pennsylvania; and San Diego, California. These systems provide steam heating to approximately 600 customers and chilled water to 90 customers. In addition, NRG Thermal owns and operates three projects that serve industrial/government customers with high-pressure steam and hot water, and an 88 MW combustion turbine peaking generation facility and an 18 MW coal-fired cogeneration facility in Dover, Delaware (included in the summary of the Eastern region).

Our thermal and chilled water assets as of September 30, 2003 are summarized in the table below.

Name and Location of Facility	Thermal Energy Purchaser/MSW Supplier	Net Owned Capacity(1)	NRG's Percentage Ownership Interest	Fuel Type
NRG Energy Center Minneapolis, MN	Approx. 100 steam customers and 40 chilled water customers	Steam: 1,403 mmBtu/hr. (411 MWt) Chilled water: 42,450 tons (149 MWt)	100%	Gas/Oil
NRG Energy Center San Francisco, CA	Approx. 185 steam customers	Steam: 490 mmBtu/hr. (144 MWt)	100%	Gas
NRG Energy Center Harrisburg, PA	Approx. 295 steam customers and 2 chilled water customers	Steam: 490 mmBtu/hr. (144 MWt) Chilled water: 1,800 tons (8 MWt)	100%	Gas/Oil
NRG Energy Center Pittsburgh, PA	Approx. 30 steam and 30 chilled water customers	Steam: 260 mmBtu/hr. (76 MWt) Chilled water: 12,580 tons (44 MWt)	100%	Gas
NRG Energy Center San Diego, CA	Approx. 20 chilled water customers	Chilled water: 8,000 tons (28 MWt)	100%	Gas
NRG Energy Center Rock-Tenn, MN	Rock-Tenn Company	Steam: 430 mmBtu/hr. (126 MWt)	100%	Coal/Gas
Camas Power Boiler, Washington	Georgia-Pacific Corp.	Steam: 200 mmBtu/hr. (59 MWt)	100%	Biomass
NRG Energy Center Dover, DE	Kraft Foods Inc.	Steam: 190 mmBtu/hr. (56 MWt)	100%	Coal
NRG Energy Center Washco, MN	Andersen Corp., MN Correctional Facility	Steam: 160 mmBtu/hr. (47 MWt)	100%	Coal/Gas

(1) Thermal production and transmission capacity is based on 1,000 Btus per pound of steam production or transmission capacity. The unit mmBtu is equal to one million Btus.

Energy Marketing

Our energy marketing subsidiary, NRG Power Marketing Inc., or "PMI," began operations in 1998. PMI provides a full range of energy management services for our domestic generation facilities. These services are provided under bilateral contracts or agency agreements pursuant to which PMI manages the sales and purchases of energy, capacity and ancillary services from the facilities, procures the fuel (coal, oil and natural gas) and associated transportation and manages the emission allowance credits for these facilities. In addition, PMI provides all necessary ISO bidding, dispatch and transmission scheduling for the facilities. In order to more efficiently access the power and fuel markets, all fuel procurement, emissions allowance and energy marketing activities on behalf of the facilities is managed by PMI. PMI utilizes its contractual arrangements with third parties in order to procure fuel and to sell energy, capacity and ancillary services to minimize administrative costs and burdens and reduce the amount of collateral requirements imposed by third party suppliers and purchasers, thereby easing credit and liquidity concerns. PMI's fuel and energy services is limited to such activities that are necessary for the operation of the company's generating facilities and management of commodity price risk.

Significant Dispositions of Non-Strategic Assets

Since 2002, we sold or made arrangements to sell a number of consolidated businesses and equity investments in an effort to reduce our debt. Dispositions completed during 2003 and pending dispositions as of November 30, 2003 are summarized in the following chart:

Asset (Location)	Transaction Description	Closing Date
Completed Transactions:		
ECKG (Czech Republic)	Sale of NRG's 45% interest	1/10/03
Brazos Valley (Texas)	Transfer of project to project banks	1/31/03
Killingholme (England)	Transfer of project to project banks	1/31/03
NEO Landfill Gas and Minn. Methane (Various)	Hudson United Bank Foreclosure	5/7/03
Kondapalli (India)	Sale of 30% equity interest	5/30/03
Mustang (Texas)	Sale of 25% equity interest	7/7/03
Langage (England)	Sale of NRG's 100% interest	8/5/03
Timber Energy (Power Plant)	Sale of NRG's 50% interest	9/18/2003
Central San Antonio Libertador Gas Turbine Package	Sale of NRG's turbines	10/20/03
Timber Energy (Chip Mill)	Sale of NRG's 50% interest	10/30/2003
Cahua and CNP	Sale of NRG's 100% interest	11/21/03
Pending Dispositions:		
Loy Yang (Australia)*	Sale of NRG's 25% interest	Mid 2004
McClain (Oklahoma)	Sale of NRG's 77% interest	12/31/03

* Subject to approval by Australian regulatory authorities.

In addition to the pending dispositions described in the table above, we are currently marketing other assets. Currently, there are no definitive agreements in place with respect to the sale of other assets and we cannot assure you that we will be able to enter into any definitive agreements on commercially reasonable terms or at all.

Significant Customers

During 2002, we derived approximately 22.1% of our revenues from majority-owned operations from one customer: NYISO. An ISO is a FERC-regulated entity that manages the transmission assets that are collectively under the control of the ISO to provide non-discriminatory access to the transmission grid. The NYISO exercises operational control over most of New York State's transmission facilities.

During 2001, we derived approximately 51.5% of our revenues from majority owned operations from two customers: NYISO (33.9%) and CL&P (17.6%). During 2000, we derived approximately 41.6% of our revenues from majority owned operations from two customers: the NYISO (26.8%) and CL&P (14.8%).

We anticipate that NYISO will continue to be a significant customer given the scale of our asset base in the NYISO control area. The CL&P contract will end in December 2003 and thus the concentration of revenues from this one customer will likely decline.

NRG Worldwide Operations

NRG Worldwide Operations, or "NRG Operations," is a diversified organization that provides operating and maintenance services to our generation fleet. These services include providing experienced personnel for the operation and administration of each facility and oversight out of the corporate office to balance resources, share expertise and best practices and ensure the optimum utilization of resources available to the fleet. In addition, NRG Operations provides overall fleet management, strategic planning and the development and dissemination of consistent fleet wide policies and practices.

We believe maintaining this in-house technical and management expertise is advantageous to us because, we can, among other things:

- use our buying leverage to obtain economies of scale when procuring equipment and materials;

- maximize the efficiency of plants by contributing to critical technical decisions in connection with marketing obligations and opportunities of PMI, whether plant specific or for a portfolio of assets; and

- efficiently maintain specialized technical and management expertise that assists plants with complex technical issues and plant improvements on an as-needed basis.

NRG Operations typically provides services to project entities by entering into a Service Agreement with the project company. Service Agreements provide a contractual basis and definition of the rights and responsibilities of the operating companies and the asset owners for each project that is operated by NRG Operations. NRG Operations' operating companies will provide a uniform suite of services that address management, technical, contractual, commercial and other business issues as well as safety, security and environmental compliance services and strategies. Specifically, standard services provided by NRG Operations include, but are not limited to:

- operations, maintenance, technical and business management and oversight;

- CMMS (computerized maintenance management system) support;

- standard operating system operating policies, audits and support;

- high energy piping program;

- root cause analysis;

- reliability centered/predictive and preventive maintenance systems;

- transformer testing program;

- performance testing, evaluation and database management;

- technical assessments/life plan/five year plan;

- personnel and labor agreement negotiation and management;

- fuel assessment and inventory management;

- vendor partnering and strategic alliances;

- procurement and inventory management;

- project evaluations and proposals;

- safety audits and safety program management;

- environmental audits, environmental program management, environmental assessments, asset and portfolio compliance strategies;

- community, governmental and regulatory affairs management; and

- asset management and related financial service.

Seasonality and Price Volatility

Annual and quarterly operating results can be significantly affected by weather and price volatility. Significant other events, such as demand for natural gas for heating and reduced hydroelectric capacity due to drier seasons can increase seasonal fuel and power price volatility. We derive a majority of our annual

revenues in the months of May through September, when demand for electricity is the highest. Further, volatility is generally higher in the summer months due to the effect of temperature variations.

Source and Availability of Raw Materials

Our raw material requirements primarily include various forms of fossil fuel energy sources, including oil, natural gas and coal. We obtain our oil, natural gas and coal from multiple sources and availability is generally not an issue, although localized shortages and supplier financial stability issues can and do occur. The prices of oil, natural gas and coal are subject to macro-and micro-economic forces that can change dramatically in both the short term and the long term. For example, the prices of natural gas and oil were particularly high during the winter of 2002-2003 due to weather volatility and geo-political uncertainty in the Middle East. Oil, natural gas and coal represented approximately 46% of our cost of operations during the year ended December 31, 2002.

Federal Energy Regulation

Federal Energy Regulatory Commission. FERC is an independent agency that regulates the transmission and wholesale sale of electricity in interstate commerce under the authority of the FPA. The FPA also gives FERC jurisdiction over: a public utility's issuance of securities or assumption of liabilities; the dispositions of jurisdictional assets; and the licensing and inspecting of private, municipal and state-owned hydroelectric projects. In addition, FERC determines whether a generation facility qualifies for EWG status under PUHCA. FERC also determines whether a generation facility meets the ownership and technical criteria of a Qualifying Facility, or "QF," under PURPA.

Federal Power Act. The FPA gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and transmission of electricity in interstate commerce. FERC regulates the owners of facilities used for the wholesale sale of electricity or transmission in interstate commerce as "public utilities." The FPA also gives FERC jurisdiction to review certain transactions and numerous other activities of public utilities. Our QFs are exempt from the FERC's FPA rate regulation.

Public utilities are required to obtain FERC's acceptance of their rate schedules for wholesale sales of electricity. Because our non-QF operating companies are selling electricity in the wholesale market, such operating companies are deemed to be public utilities for purposes of the FPA. In most cases, FERC has granted our operating companies the authority to sell electricity at market-based rates. Usually, the FERC's orders that grant our operating companies market-based rate authority reserve the right to revoke or revise that authority if FERC subsequently determines that we possess excessive market power. If our operating companies were to lose their market-based rate authority, such operating companies may be required to obtain FERC's acceptance of a cost-of-service rate schedule and may become subject to the accounting, record-keeping and reporting requirements that are imposed on utilities with cost-based rate schedules.

In addition, the FPA gives FERC jurisdiction over a public utility's issuance of securities or assumption of liabilities. However, FERC usually grants blanket approval for future securities issuances or assumptions of liabilities to entities with market-based rate authority. In the event that one of our public utility operating companies were to lose its market-based rate authority, our future securities issuances or assumptions of liabilities could require prior approval of the FERC. In addition, FERC has issued an order in connection with our reorganization that implies that FERC believes that NRG Energy, which is not a public utility under the FPA, may require FERC's approval before it can issue securities or assume liabilities subsequent to its reorganization and completion of the Refinancing Transactions.

The FPA also requires the FERC's prior approval for the transfer of control over assets subject to FERC's jurisdiction. FERC has jurisdiction over certain facilities used to interconnect our EWG projects with the transmission grid, and over the filed rate schedules and tariffs of our EWG and power marketer operating companies. Thus, transferring these assets would require FERC approval.

In New England, New York, the Mid-Atlantic region, the Midwest and California, FERC has approved ISOs. Most of these ISOs administer a wholesale centralized bid-based spot market in their regions pursuant to tariffs approved by FERC. These tariffs/market rules dictate how the spot markets operate and how entities with market-based rates shall be compensated within those markets. The ISOs in these regions also control access to, the pricing of, and the operation of the transmission grid within their footprint. Outside of ISO-controlled regions, we are allowed to sell at market-based rates as determined by willing buyers and sellers. Access to, pricing for, and operation of the transmission grid in such regions is controlled by the local transmission owning utility according to its Open Access Transmission Tariff approved by FERC.

Public Utility Holding Company Act. PUHCA defines any entity that owns, controls or has the power to vote 10% or more of the outstanding voting securities of a "public utility company" as a "holding company." Unless exempt, a holding company is required to register with the SEC, and it and its Subsidiaries (i.e., a company with 10% of its voting securities held by the registered holding company) become subject to extensive regulation. Registered holding companies under PUHCA are required to limit their utility operations to a single, integrated utility system and divest any other operations that are not functionally related to the operation of the utility system. In addition, a company that is a Subsidiary of a registered holding company is subject to financial and organizational regulation, including approval by the SEC of certain financings and transactions. Domestic generating facilities that qualify as QFs and/or that have obtained EWG status from FERC are not considered "public utility companies" for purposes of PUHCA. Each of our domestic operating subsidiaries has been designated by FERC as an EWG or is otherwise exempt from PUHCA because it is a QF under PURPA.

Because our operating subsidiaries have EWG or QF status, we do not qualify as a "holding company" under PUHCA. However, prior to the effective date of the NRG plan of reorganization, we fit the definition of a "Subsidiary" of a registered holding company, Xcel Energy, making us subject to regulation under PUHCA. After the effective date, we will cease to be a Subsidiary of Xcel Energy and, under current law, will not be subject to regulation as a "registered holding company" or a "Subsidiary" of a registered holding company under PUHCA as long as (i) we do not become a Subsidiary of another registered holding company and (ii) the projects in which we have an interest (1) qualify as QFs under PURPA, (2) obtain and maintain EWG status under Section 32 of PUHCA, (3) obtain and maintain FUCO status under Section 33 of PUHCA, or (4) are subject to another exemption or waiver. If our projects were to cease to be exempt and we were to become subject to SEC regulation under PUHCA, it would be difficult for us to comply with PUHCA absent a substantial restructuring.

After our reorganization, FirstEnergy, a registered holding company, is expected to own between 5-10% of our stock if FERC approves FirstEnergy's application to acquire shares of NRG. If so, then NRG would be considered an "Affiliate" of a registered holding company. While an "Affiliate" is subject to substantially less regulation than a "Subsidiary," being an Affiliate of FirstEnergy could limit the transactions that we could enter into with FirstEnergy without notifying the SEC.

Regulatory Developments. FERC is attempting to deregulate the wholesale market by requiring transmission owners to provide open, non-discriminatory access to electricity markets and the transmission grid. In April 1996, FERC issued Orders 888 and 889, requiring all public utilities to file "open access" transmission tariffs that give wholesale generators, as well as other wholesale sellers and buyers of electricity, access to transmission facilities on a non-discriminatory basis. This led to the formation of the ISOs described above. On December 20, 1999, FERC issued Order 2000, encouraging the creation of regional transmission organizations, or "RTOs." Finally, on July 31, 2002, FERC issued its Notice of Proposed Rulemaking regarding Standard Market Design, or "SMD." All three orders were intended to eliminate market discrimination by incumbent vertically integrated utilities and to provide for open access to the transmission grid. The status of FERC's RTO and SMD initiatives is uncertain. On April 28, 2003, FERC issued a white paper describing proposed changes to the proposed SMD rulemaking that would, among other things, allow for more regional differences. In addition, the Energy Bill pending before Congress could restrict FERC's ability to implement these initiatives.

The full effect of these changes on us is uncertain at this time, because in many parts of the United States, it has not been determined how entities will attempt to comply with FERC's initiatives. At this time, five ISOs have been approved and are operational: ISO-NE in New England; the NYISO in New York; PJM in the Mid-Atlantic region; the Midwest Independent System Operation, or "MISO," in the Central Midwest region; and the Cal ISO in California. Two of these ISOs, PJM and MISO, have been found to also qualify as RTOs. ISO-NE, together with New England transmission owners, has filed a proposal for an RTO in New England. A number of other entities in various regions of the United States have also requested that FERC approve their organizations as RTOs.

We are impacted by rule/tariff changes that occur in the existing ISOs and RTOs. The ISOs that oversee most of the wholesale power markets have in the past imposed, and may in the future continue to impose, price limitations and other mechanisms to address some of the volatility in these markets. For example, ISO-NE, NYISO, PJM and Cal ISO have imposed price limitations. These types of price limitations and other regulatory mechanisms may adversely impact the profitability of our generation facilities that sell energy into the wholesale power markets. In addition, the regulatory and legislative changes that have recently been enacted in a number of states in an effort to promote competition are novel and untested in many respects. These new approaches to the sale of electric power have very short operating histories, and it is not yet clear how they will operate in times of market stress or pressure, given the extreme volatility and lack of meaningful long-term price history in many of these markets and the imposition of price limitations by independent system operators.

The Energy Bill currently pending before Congress would repeal PUHCA one year after passage and amend PURPA, and provide FERC with additional jurisdiction over the books and accounts of certain holding companies. If the repeal/amendment of PURPA or PUHCA occurs, either separately or as part of legislation designed to encourage the broader introduction of wholesale and retail competition, the significant advantages that wholesale power generators currently enjoy may be eliminated or sharply curtailed, and the ability of regulated utility companies to compete more directly with wholesale power generators could be increased. To the extent competitive pressures increase and the pricing and sale of electricity assumes more characteristics of a commodity business, the economics of domestic wholesale power generation projects may come under increasing pressure. Deregulation may not only continue to fuel the current trend toward consolidation among domestic utilities, but may also encourage the disaggregation of vertically-integrated utilities into separate generation, transmission and distribution businesses. At this time, the Energy Bill has stalled in Congress and it is unclear whether it will be passed into law. In addition, if the Energy Bill is passed, it is unclear what impact, if any, the new rules for holding companies would have on us.

Environmental Matters

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

Regulatory compliance for the construction of new facilities is a costly and time-consuming process. Intricate and rapidly changing environmental regulations may require major capital expenditures for permitting and create a risk of expensive delays or material impairment of project value if projects cannot function as planned due to changing regulatory requirements or local opposition. In addition, environmental laws have become increasingly stringent over time, particularly with regard to the regulation of air emissions from our plants. Such laws generally require regular capital expenditures for power plant upgrades and modifications and for the installation of certain pollution control equipment. Therefore, we seek to integrate the consideration of potential environmental impacts into every business decision we make, and by doing so, strive to improve our competitive advantage by meeting or exceeding environmental and safety requirements pertaining to the management and operation of our assets.

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

Domestic Environmental Regulatory Matters

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

We establish accruals where reasonable estimates of probable environmental and safety liabilities are possible. We adjust the accruals when new remediation or other environmental liability responsibilities are discovered and probable costs become estimable, or when current liability estimates are adjusted to reflect new information or change in the law.

U.S. Federal Environmental Initiatives

Several federal regulatory and legislative initiatives are being undertaken in the U.S. to further limit and control pollutant emissions from fossil-fuel-fired combustion units. Although neither the exact impact of these initiatives nor the final form that these initiatives will take are known at this time, all of our power plants will likely be affected in some manner by the expected changes in federal environmental laws and regulations. In Congress, legislation has been proposed that would impose annual caps on U.S. power plant emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury and, in some instances, carbon dioxide (CO_2). We are currently participating in the debates around such legislative proposals as a member of the Electric Power Supply Association. Federal legislation relating to NO_x, SO_2 and mercury is likely in the next two years. The prospects for passage of the legislation relating to CO_2 is more uncertain. The U.S. Environmental Protection Agency, or “EPA,” is scheduled to propose in December 2003 and finalize in December 2004 rules governing mercury emissions from power plants. These mercury rules will likely require compliance within three years after the rules are promulgated with a possible one year extension for existing sources. In support of this schedule, the EPA and critical stakeholders, some of which are aligned with our interests, are presently conducting a thorough review of existing power plant mercury emissions data. Since these mercury rules have not yet been proposed and legislation has not yet supplanted them, it is not possible for us to determine the extent to which the rules will affect our domestic operations; however, they will likely have a much greater affect on our coal facilities.

The EPA has finalized federal rules governing ozone season NO_x emissions across the eastern United States. These ozone season rules are being implemented in two phases. The first phase of restrictions occurred in the Ozone Transport Commission region during the 2003 ozone season; all of our generating units in the northeast and mid-atlantic regions are included in this part of the program. The second phase of NO_x reductions will extend to states within the Ozone Transport Assessment Group region and restrict 2004 and subsequent ozone season NO_x emissions in most states east of the Mississippi River. These rules, which will continue until further notice, require one NO_x allowance to be held for each ton of NO_x emitted from any fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system that (i) at any time on or after January 1, 1995, served as a generator with a nameplate capacity greater than 25 MW and sold any amount of electricity or (ii) has a maximum design heat input greater than 250 mmBtu/hr. Our facilities that are subject to this rule in the Central and Eastern regions have been allocated NO_x emissions allowances, but we expect that those allowances may not be sufficient for the anticipated operation for all of these facilities.

Our facilities in Illinois in the Central region are also subject to this program. We expect that our Illinois sources will receive initial allowances out of a new source set aside. The future operating capacity of these Illinois plants will determine whether the initial allowances are sufficient. Where insufficient allowances exist, we must purchase NO_x allowances from sources holding excess allowances. The need to purchase these additional NO_x allowances could have a material adverse effect on our operations in these regions.

During the first quarter of 2002, the EPA proposed new rules governing cooling water intake structures at existing power facilities. These rules are scheduled to be finalized by February 16, 2004. The proposed rules specify certain location, design, construction and capacity standards for cooling water intake structures at existing power plants using a large amount of cooling water. These rules will require implementation of the best technology available for minimizing adverse environmental impacts unless a facility shows that such standards would result in very high costs or little environmental benefit. The proposed rules would require our facilities that withdraw water in amounts greater than 50 million gallons per day to include certain surveys, plans, operational measures and restoration measures that combined would act to minimize adverse environmental impacts when these facilities submit applications to renew their National Pollutant Discharge Elimination System permits. After implementation of these rules, the EPA intends to establish similar regulations for facilities that withdraw between two and 50 million gallons per day. These anticipated cooling water intake structure rules could have a material adverse effect on our operations.

Other federal initiatives that could affect us, including some that would govern regional haze and fine particulate matter and the 8-hour average ozone standard, are underway, but under extended compliance implementation time frames ranging from 2009 and beyond.

Regional U.S. Regulatory Initiatives

West Coast Region. The El Segundo and Long Beach Generating Stations are both regulated by the South Coast Air Quality Management District's, or "SCAQMD's," Regional Clean Air Incentives Market, or "RECLAIM," program. This program, which regulates NO_x emissions in the Los Angeles area, was amended on May 11, 2001, and mandated major changes with respect to air emissions control at power generation facilities in southern California. New RECLAIM Rule 2009 required that all existing power generation facilities meet Best Available Retrofit Control Technology, or "BARCT," for NO_x emissions from all utility boilers by January 1, 2003, and for NO_x emissions from all peaking units by January 1, 2004. Under the new rule, existing power generation facilities were required to submit compliance plans by September 1, 2001, listing how each unit at the stations would meet BARCT by the deadlines. El Segundo's compliance plan did not propose additional NO_x controls to meet BARCT since Units 3 & 4 are already equipped with acceptable selective catalytic reduction, or "SCR," technology (first installed on Unit 4 in 1995 and on Unit 3 in 2001). Further, Units 1 & 2 were decommissioned at the end of 2002 so the new requirements did not apply to those two units. SCAQMD approved the El Segundo Rule 2009 Compliance Plan on October 17, 2002, indicating that the SCRs on Units 3 & 4 meet BARCT and requiring that Units 1 & 2 be retired on or before December 31, 2002. SCAQMD approved the Long Beach Generating Station Rule 2009 Compliance Plan on April 25, 2002, which proposed modifications to the Long Beach NO_x control system by December 31, 2002, and specified a new NO_x emission concentration limit of 16.6 parts per million. The Long Beach plant completed all control system modifications and demonstrated compliance with 16.6 parts per million limit before the December 31, 2002 deadline. Therefore, all Long Beach and El Segundo units have met the Rule 2009 BARCT requirement, and we do not at this time anticipate additional material capital expenditures associated with the amended RECLAIM rules.

Eastern Region. Final rules implementing changes in air regulations in Massachusetts and Connecticut were promulgated in 2000. The Connecticut rules required that existing facilities reduce their emissions of SO_2 in two steps. The first SO_2 milestone took place on January 1, 2002 and the second SO_2 milestone occurred on January 1, 2003. Our plants in Connecticut have operated in compliance with the first phase rules and are now operating in compliance with the second phase rules. Connecticut's rules governing emissions of NO_x were also modified in 2000 to restrict the average, non-ozone season NO_x emission rate to 0.15 pound per million Btu heat input. We plan to comply with the new NO_x rules, in part, through selective firing of natural gas, use of selective non-catalytic reduction technology presently installed at our Norwalk

Harbor and Middletown Power Stations, improved combustion controls, use of emission reduction credits and purchase of allowances. In 2002, the Connecticut legislature passed a law further tightening air emission standards by eliminating in-state emissions credit trading subsequent to January 1, 2005 as a means of meeting Department of Environmental Protection regulatory standards for SO_2 emissions from older power plants. The termination of SO_2 emissions trading in Connecticut by 2005 could have a material adverse effect on our operations in that state.

The new Massachusetts rules set forth schedules under which six existing coal-fired power plants in-state were required to meet stringent emission limits for NO_x, SO_2, mercury and CO_2. The state has reserved the issue of credit creation and trading for the control of carbon monoxide and regulations on the control of particulate matter emissions for future consideration. On February 25, 2003, we received from the Massachusetts Department of Environmental Protection (MADEP) a permit to install natural gas reburn technology to meet the NO_x and SO_2 limits specified in the new rules at our Somerset Generating Station. We anticipate incurring total capital expenditures of approximately $5.6 million to implement reburn technology at Somerset Station, most of which to-date has been expended. Remaining expected costs associated with implementing the reburn technology at the Somerset Station include a small hold-back related to demonstrating conformance with vendor guarantees and the final efforts related to completing the New England gas connection. Together, we expect these two elements to represent less than $700,000.

In September 2003, MADEP proposed mercury regulations that would affect the Somerset Station. The first phase would go into effect on October 1, 2006 and require the Somerset Station to meet a mercury rate of 0.0075 Pounds/ GWh or an 85% reduction inlet-to-outlet. The second phase, which goes into effect on October 1, 2012, would require a rate of 0.0025 Pounds/ GWh, or a 95% reduction inlet-to-outlet. Public hearings on these rules are scheduled for mid November 2003. We believe we can comply with any future mercury reductions required by the rules through achieving early reductions of mercury via early implementation of the natural gas reburn technology and with our January 1, 2010 commitment to shutdown Somerset Station's existing boiler. We are still considering our options with respect to how we will address MADEP's CO_2 emission standards. Such options include using early reductions of CO_2 achieved through early implementation of the natural gas reburn technology, purchase of creditable greenhouse gas reductions obtained from third parties, or by filing a legal challenge with respect to MADEP's legal authority to regulate CO_2 emissions.

New York issued rules on April 17, 2003 that became effective on May 17, 2003 that reduce allowable SO_2 and NO_x emissions from large, fossil-fuel-fired combustion units in New York State (6 NYCRR Part 237: Acid Deposition Reduction NO_x Budget Trading Program and Part 238: Acid Deposition Reduction SO_2 Budget Trading Program). These rules affect every NRG Energy generator in-state except the Astoria Gas Turbines. We filed a petition on August 15, 2003 challenging the final rules. This matter has not been resolved. Our strategy for complying with the new rules will be to generate early reductions of SO_2 and NO_x associated with fuel switching and use such reductions to extend the timeframe for implementing technological controls, which could include the addition of flue gas desulfurization, low NO_x combustion technologies and/or selective catalytic reduction, or "SCR," equipment. We anticipate that we could incur capital expenditures up to $200 million in the 2010 through 2012 timeframe to implement upgrades and modifications to our plants in New York (other than Astoria) to meet these new state regulatory requirements if we cannot address such requirements through use of compliant fuels and/or plantwide applicability limits.

While no material impending rule changes affecting our existing facilities have been formally proposed, Delaware has considered in 2003 whether or not to develop Maximum Achievable Control Technology standards for mercury. In support of this effort, the state is beginning to test large combustion sources for mercury emissions. In addition, the state is considering establishing emissions reduction rulemaking that could affect our assets in Delaware. Further, the state is establishing Total Maximum Daily Loading standards for mercury in its watersheds. We are participating as a stakeholder in such policy-making efforts and participating with the Governor's Energy Task Force, legislators, and Delaware Department of Natural Resources and Environmental Control senior staff to ensure that any rules promulgated adequately consider impacts on our in-state sources.

Central Region. The Louisiana Department of Environmental Quality has promulgated State Implementation Plan revisions to bring the Baton Rouge ozone non-attainment area into compliance with National Ambient Air Quality Standards. We participated in the development of the revisions, which require the reduction of NO_x emissions at the gas-fired Big Cajun I Power Station and coal-fired Big Cajun II Power Station to 0.1 pounds NO_x per million Btu heat input and 0.21 pounds NO_x per million Btu heat input, respectively. This revision of the Louisiana air rules would appear to constitute a change-in-law covered by the agreement between Louisiana Generating LLC and the electric cooperatives allowing the costs of added combustion controls to be passed through to the cooperatives. The capital cost of combustion controls required at the Big Cajun II Generating Station to meet the State's NO_x regulations will total about $10.0 million each for Units 1 & 2. Unit 3 has already made such changes.

Domestic Site Remediation Matters

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

West Coast Region. The Asset Purchase Agreements for the Long Beach, El Segundo, Encina and San Diego gas turbine generating facilities provide that Southern California Edison and San Diego Gas & Electric retain liability and indemnify us for existing soil and groundwater contamination that exceeds remedial thresholds in place at the time of closing. We and our business partner for these facilities conducted Phase I and Phase II Environmental Site Assessments at each of these sites for the purpose of identifying such existing contamination and provided the results to the sellers. Southern California Edison and San Diego Gas & Electric have agreed to undertake corrective action at the Encina and San Diego gas turbine generating sites related to issues identified in these assessments. Spills and releases of various substances have occurred at these sites since establishing the historical baseline, all of which have been or will be remediated in accordance with existing laws as described further below.

A lubricating oil leak in November 2002 from underground piping at the El Segundo Generating Station contaminated soils adjacent to and underneath the Unit 1 powerhouse. We excavated and disposed of contaminated soils that could be removed in accordance with existing laws. We filed a request with the Los Angeles Regional Water Quality Control Board to allow contaminated soils to remain underneath the building foundation until the building is demolished. In March 2003, the Los Angeles Regional Water Quality Control Board approved the request.

A diesel fuel spill to on-site surface containment occurred at the Cabrillo Power II LLC Kearny Combustion Turbine facility (San Diego) in February 2003. Emergency response and subsequent remediation activities were promptly completed. An application for confirmation sampling for the site was submitted to the San Diego County Department of Environmental Health in September 2003. It is expected that the Department will authorize the sampling plan and confirmation sampling will be completed in 2004.

Three San Diego Combustion Turbine facilities, formerly operating pursuant to land leases with the United State Navy, are currently being decommissioned with equipment being removed from the sites and remediation activities occurring where necessary. All remedial activities are being completed pursuant to the requirements of the United States Navy and the San Diego County Department of Environmental Health. Decommissioning and remediation activities are expected to be complete in 2004.

Eastern Region. Coal ash is produced as a by-product of coal combustion at the Dunkirk, Huntley, Indian River and Somerset Generating Stations. We currently attempt to direct our coal ash to beneficial uses such as road base, cement replacement, cinder blocks and flowable fill materials. Even so, significant amounts of ash are landfilled at on and off-site locations. At Indian River, Dunkirk and Huntley, ash is disposed at landfills owned and operated by us. No material liabilities outside the costs associated with closure, post-closure care and monitoring are expected at these facilities, currently estimated at approximately $5.8 million. We maintain financial assurance to cover costs associated with closure, post-closure care and monitoring activities by providing cash collateral, corporate guarantees or meeting certain financial ratio tests.

We must also maintain financial assurance for closing interim status RCRA facilities at the Devon, Middletown, Montville and Norwalk Harbor Generating Stations. Previously, we have provided financial assurance via meeting specified financial tests. In April 2003, we established financial assurance via a trust fund instrument requiring complete collateralization of closure and post-closure-related costs.

Historical clean-up liabilities were inherited as a part of acquiring the Somerset, Devon, Middletown, Montville, Norwalk Harbor, Arthur Kill and Astoria Generating Stations. We have recently satisfied clean-up obligations associated with the Ledge Road property (inherited as part of the Somerset acquisition). Site contamination liabilities arising under the Connecticut Transfer Act at the Devon, Middletown, Montville and Norwalk Harbor Stations have been identified and are currently being refined as part of on-going site investigations. We do not expect to incur material costs associated with completing the investigations at these Stations or future work to close and monitor landfill areas pursuant to the Connecticut requirements. Remedial liabilities at the Arthur Kill Generating Station have been established in discussions between us and the New York State Department of Environmental Conservation and are expected to cost between approximately $1.0 million and $2.0 million. Remedial investigations are ongoing at the Astoria Generating Station. At this time, our long-term cleanup liability at this site is expected to be approximately $2.5 million to $4.3 million.

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

Central Region. Liabilities associated with closure, post-closure care and monitoring of the ash ponds owned and operated on site at the Big Cajun II Generating Station are addressed through the use of a trust fund maintained by us (one of the instruments allowed by the Louisiana Department of Environmental Quality for providing financial assurance for expenses associated with closure and post-closure care of the ponds). The value of the trust fund is approximately $4.8 million and we are making annual payments to the fund in the amount of approximately $116,000.

International Environmental Matters

Most of the foreign countries in which we own or may acquire or develop independent power projects have environmental and safety laws or regulations relating to the ownership or operation of electric power generation facilities. These laws and regulations are typically significant for international wholesale power producers because they are still changing and evolving. In particular, our international power generation facilities will likely be affected by evolving emissions limitations and operational requirements imposed by the Kyoto Protocol, which is an international treaty related to greenhouse gas emissions, and country-based restrictions pertaining to global climate change concerns.

We retain appropriate advisors in foreign countries and seek to design our international asset management strategy to comply with and take advantage of opportunities presented by each country's environmental and safety laws and regulations. There can be no assurance that changes in such laws or regulations will not adversely effect our international operations.

Australia. NRG's Australian power facilities are licensed under the environment protection legislation of the state in which they are located, and are subject to compliance with these state authorizations. The most significant environmental issue for the Australian NRG businesses is the response to global climate change. Climate change issues are considered a long-term issue (e.g., 2010 and beyond), and the Australian government's response to date has included a number of initiatives, all of which have had no impact or minimal impact on our current operations. The Australian government has stated that Australia will achieve its Kyoto Protocol target of 108% of 1990 greenhouse gas emission levels for the 2008 to 2012 reporting period but that Australia will not ratify the Kyoto Protocol. Each Australian state government is considering implementing a number of climate change initiatives that will vary considerably state to state. We currently expect that climate change initiatives will not have a material adverse effect on our businesses in Australia.

MIBRAG/Schkopau, Germany. CO_2 emissions trading is supposed to start in 2005, but we cannot quantify the possible effect of this trading on our operations in Germany at this time because implementation details are still being negotiated among businesses, lobbyists and regulatory authorities. Fundamental issues such as "grandfathering" existing plants or availability of credits for plants previously closed or upgraded are still unsettled. We are working with specialized consultants, the Environmental Ministry of Sachsen Anhalt and MIBRAG to understand developments and minimize any adverse effects. Proposed changes in sections 13 and 17 of the German Emission Control Directive are expected to tighten emissions limits for plants firing conventional fuels or co-firing waste products. As with CO_2 emissions trading, these changes are currently being vigorously debated with issues such as exemptions based on size or purpose of plants and "grandfathering."

The European Union's Groundwater Directive and Mine Wastewater Management Directive are in the rule-making stage with the final outcome still under debate. Given the uncertainty regarding the possible outcome of the on-going debate on these directives, we cannot quantify at this time the possible effect such requirements would have on our future coal mining operations in Germany.

A new law specifically dealing with the relocation of residents of Heuersdorf in the path of the mining plan has been introduced in the legislature of Sachsen Anhalt and is expected to be enacted in March 2004. There are numerous potential court challenges still to come in the process. Outcomes and durations are difficult to predict. MIBRAG continues its political and legal work in an effort to obtain a favorable resolution.

UK. Our Enfield Generating Station uses state-of-the-art combined cycle technology and is set to fire natural gas as its primary fuel. Currently the facility complies with all conditions in its environmental permits and its operation is not under challenge by any governmental or non-governmental parties.

Competition

The results of the restructuring of the wholesale power generation power industry are impossible to predict, but they may include consolidation within the industry, the sale or liquidation of certain competitors, the re-regulation of certain markets and the long-term reduction in new investment into the industry. Under any scenario, however, we anticipate that we will continue to face competition from numerous companies in the industry. It is anticipated that FERC will continue its effort to facilitate the competitive energy market place throughout the country by encouraging utilities to voluntarily participate in RTOs.

Many companies in the regulated utility industry, with which the wholesale power industry is closely linked, are also restructuring or reviewing their strategies. Several of these companies are discontinuing their unregulated investments, seeking to divest of their unregulated subsidiaries or attempting to have their regulated subsidiaries acquire their unregulated subsidiaries. This may lead to increased competition between the regulated utilities and the unregulated power producers within certain markets.

Employees

As of September 30, 2003, we had 3,104 employees, approximately 474 of whom are employed directly by NRG Energy, Inc. and approximately 2,630 of whom are employed by our wholly owned subsidiaries and affiliates. Approximately 1,723 employees are covered by bargaining agreements. We have experienced no significant labor stoppages or labor disputes at our facilities.

Legal Proceedings

We are involved in the following material legal proceedings. Claims arising from these proceedings will be treated in accordance with the NRG plan of reorganization.

California Wholesale Electricity Litigation and Related Investigations

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

This action was filed in state court on March 11, 2002 against us, Dynegy, Dynegy Power Marketing Inc., Xcel Energy, West Coast Power and four of West Coast Power's operating subsidiaries. It alleges that the defendants violated California Business & Professions Code § 17200 by selling ancillary services to the Cal ISO, and subsequently selling the same capacity into the spot market. The California Attorney General seeks injunctive relief as well as restitution, disgorgement and civil penalties.

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

The Attorney General filed motions to remand, which the defendants opposed in July of 2002. In an Order filed in early September 2002, Judge Walker denied the remand motions. The Attorney General has appealed that decision to the United States Court of Appeal for the Ninth Circuit, and the appeal is pending. The Attorney General also sought a stay of proceedings in the district court pending the appeal, and this request was also denied. A "Notice of Bankruptcy Filing" respecting us was filed in the Ninth Circuit and in the District Court in mid-December 2002. The Attorney General filed a paper asserting that the "police power" exception to the automatic stay is applicable here. Judge Walker agreed with the Attorney General on this issue. In a lengthy opinion filed March 25, 2003, Judge Walker dismissed the Attorney General's action against us and Dynegy with prejudice, finding it was barred by the filed-rate doctrine and preempted by federal law. The Attorney General filed a Notice of Appeal, and the appeal was argued in August 2003 and also is pending. We also filed a "Notice of Bankruptcy Filing" in the Ninth Circuit shortly after our chapter 11 filing, and the Ninth Circuit issued a stay as to us.

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

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

The action was transferred from Los Angeles to the United States District Court in San Diego and was made a part of the Multi-District Litigation proceeding described below. All defendants filed motions to dismiss and to strike in the fall of 2002. In an Order dated January 6, 2003, Judge Robert Whaley, a federal judge from Spokane sitting in the United States District Court in San Diego, pursuant to the Order of the Multi-District Litigation Panel, granted the motions to dismiss on the grounds of federal preemption and filed-rate doctrine. The plaintiffs have filed a notice of appeal, and the appeal is pending.

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

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

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

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

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

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

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

These cases were all filed in late 2000 and 2001 in various state courts throughout California. They allege unfair competition, market manipulation and price fixing. All the cases were removed to the appropriate United States District Courts, and were thereafter made the subject of a petition to the Multi-District Litigation Panel (Case No. MDL 1405). The cases were ultimately assigned to Judge Whaley. Judge Whaley entered an order in 2001 remanding the cases to state court, and thereafter the cases were coordinated pursuant to state court coordination proceedings before a single judge in San Diego Superior Court. Thereafter, Reliant Energy and Duke Energy filed cross-complaints naming various Canadian, Mexican and United States government entities. Some of these defendants once again removed the cases to federal court, where they were again assigned to Judge Whaley. The defendants filed motions to dismiss and to strike under the filed-rate and federal preemption theories, and the plaintiffs challenged the district court's jurisdiction and sought to have the cases remanded to state court. In December 2002, Judge Whaley issued an opinion finding that federal jurisdiction was absent in the district court, and remanding the cases to state court. Duke Energy and Reliant Energy then filed a notice of appeal with the Ninth Circuit, and also sought a stay of the remand pending appeal. The stay request was denied by Judge Whaley. On February 20, 2003, however, the Ninth Circuit stayed the remand order and accepted jurisdiction to hear the appeal of Reliant Energy and Duke Energy on the remand order. We anticipate that filed-rate/federal preemption pleading challenges will be renewed once the remand appeal is decided. A "Notice of Bankruptcy Filing" respecting us has also been filed in this action. We are not active in the appeal, which remains pending.

"Northern California" cases against various market participants, not including us (part of MDL 1405). These include the *Millar, Pastorino, RDJ Farms, Century Theatres, El Super Burrito, Leo's, J&M Karsant,* and the *Bronco Don* cases. We were not named in any of these cases, but in virtually all of them, either West Coast Power or one or more of the operating limited liability companies with which we are indirectly affiliated is named as a defendant. These cases all allege violation of Business & Professions Code § 17200, and are similar to the various allegations made by the Attorney General. Dynegy is named as a defendant in all these actions, and Dynegy's outside counsel is representing both Dynegy and the West Coast Power entities in each of these cases. These cases all were removed to federal court, made part of the Multi-District Litigation, and denied remand to state court. In late August 2003, Judge Whaley granted the defendants' motions to dismiss in these various cases.

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

This putative class action lawsuit was filed on November 20, 2002. In addition to naming West Coast Power-related entities as defendants, numerous industry participants are named in this lawsuit that are unrelated to West Coast Power or us. The complaint generally alleges that the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades. Named defendants in the suit are the limited liability companies established by West Coast Power for each of its four plants: El Segundo Power, LLC; Long Beach Generation, LLC; Cabrillo Power I LLC; and Cabrillo Power II LLC. We were not named as a defendant. The complaint seeks restitution and disgorgement of "ill-gotten gains," civil fines, compensatory and punitive damages, attorneys' fees and declaratory and injunctive relief. The plaintiff recently filed an amended complaint.

Jerry Egger, et al. v. Dynegy Inc., et al., Case No. 809822, Superior Court of California, San Diego County (filed May 1, 2003). This class action complaint alleges violations of California's Antitrust Law, Business and Professional Code, and unlawful and unfair business practices. The named defendants include "West Coast Power, Cabrillo II, El Segundo Power, Long Beach Generation." NRG Energy, Inc. is not named. This case now has been removed to the United States District Court, and the defendants have moved to have this case included as Multi-District Litigation along with the above referenced cases before Judge Walker. Plaintiffs have stated an intention to file a motion to remand to state court. Plaintiffs filed an amended complaint in federal court in October 2003. This case is the subject of a multi-district litigation petition.

Texas-Ohio Energy, Inc., on behalf of Itself and all others similarly situated v. Dynegy, Inc. Holding Co., West Coast Power, LLC, et al., Case No. CIV.S-03-2346 DFL GGH. This putative class action was filed on November 10, 2003, in the United States District Court for the Eastern District of California. The complaint alleges violations of the federal Sherman and Clayton Acts and California's Cartwright Act and Business and Professions Code. In addition to naming West Coast Power and Dynegy the complaint names numerous industry participants, as well as "unnamed co-conspirators." The complaint alleges that defendants conspired to manipulate the spot price and basis differential of natural gas with respect to the California market allegedly enabling defendants to reap exorbitant and illicit profits by gouging natural gas purchasers. Specifically, the complaint alleges that defendants and their co-conspirators employed a variety of false reporting techniques to manipulate the published natural gas price indices. The complaint seeks unspecified amounts of damages, including a trebling of plaintiff's and the putative class's actual damages. We are unable at this time to predict the outcome of this dispute or the ultimate liability, if any, of West Coast Power.

Investigations

FERC — California Market Manipulation

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

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

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

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

Through our subsidiary NRG West Coast Inc., we are essentially a joint venturer with Dynegy in West Coast Power, which owns, operates, and markets the power of California plants. Dynegy and its affiliates and subsidiaries are responsible for gas procurement and marketing and trading activities on behalf of the joint venture. On December 18, 2002, a Dynegy subsidiary, Dynegy Marketing & Trade, or "DMT," and West Coast Power, the "Respondents," entered into a consent Offer of Settlement and Order, or the "Consent Order," with the Commodity Futures and Trading Commission, or "CFTC." The action is captioned In re Dynegy Marketing & Trade and West Coast Power LLC, CFTC Docket No. 03-03. The CFTC asserted various violations of the Commodity Exchange Act, as well as CFTC regulations.

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

U.S. Attorney — Houston

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

U.S. Attorney — San Francisco

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

California State Senate Select Committee

This Committee, chaired by Senator Dunn, subpoenaed records from us during the Summer of 2001. We produced about 5,000 pages of documents; Dynegy produced a much larger volume of documents. The Committee is scheduled to sunset later this year.

CPUC

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

California Attorney General

In addition to the litigation it has undertaken described above, the California Attorney General has undertaken an investigation entitled “In the Matter of the Investigation of Possibly Unlawful, Unfair, or Anti-Competitive Behavior Affecting Electricity Prices in California.” In this connection, the Attorney General has issued subpoenas to Dynegy, served interrogatories on Dynegy and us, and informally requested documents and interviews from Dynegy and Dynegy employees as well as us and our employees. We responded to the interrogatories last summer, with the final set of responses being served on September 3, 2002. We have also produced a large volume of documentation relating to the West Coast Power plants. In addition, our employees in California have sat for informal interviews with representatives of the Attorney General’s office. Dynegy employees have also been interviewed.

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

Although any evaluation of the likelihood of an unfavorable outcome or an estimate of the amount or range of potential loss in the above-referenced private actions and various investigations cannot be made at this time, we note that the Gordon complaint alleges that the defendants, collectively, overcharged California ratepayers during 2000 by $4.0 billion. We know of no evidence implicating us in the various private plaintiffs’ allegations of collusion. We cannot predict the outcome of these cases and investigations at this time.

The New York Voluntary Bankruptcy Case

On May 14, 2003 NRG Energy, Inc. and certain of its U.S. affiliates (including NRG Northeast) filed voluntary petitions for reorganization under chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York, In re: NRG ENERGY, INC., et. al., Case No. 03-13024 (PCB). An order confirming the NRG plan of reorganization was entered by the bankruptcy court on November 24, 2003 and the plan is expected to become effective on December 5, 2003.

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

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

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

This matter involves a dispute between CL&P and PMI concerning which of party is responsible, under the terms of the October 29, 1999 SOS contract, for costs related to congestion and losses associated with the implementation of standard market design, or "SMD-Related Costs." CL&P has withheld, in addition to the $30 million discussed above, approximately $70 million from amounts owed to PMI, claiming that it is entitled under the contract to offset those additional amounts for SMD-Related Costs. PMI cannot estimate at this time the likelihood of success in this matter, or the overall exposure for SMD-Related Costs for the full term of the contract.

Connecticut Light & Power — Related Proceedings at the Federal Energy Regulatory Commission, the United States District Court for the Southern District of New York, and the United States Court of Appeals for the D.C. Circuit and the Second Circuit

In May, 2003, PMI took steps to terminate or reject in bankruptcy the subject Standard Offer Services contract. CL&P, the Connecticut Attorney General and the Connecticut Department of Public Utility Control, or "DPUC," sought and obtained from FERC an Order dated May 16, 2003, temporarily requiring PMI to continue to comply with the terms of the contract, pending further notice from FERC. Thereafter, On June 2, 2003, the bankruptcy court issued its Order specifically authorizing PMI's rejection of the contract, and by Order dated June 12, 2003, the bankruptcy court granted PMI's motion for a temporary restraining order staying all actions by CL&P, the Connecticut Attorney General and the DPUC to enforce or apply the above-referenced FERC Order and affording PMI leave to cease its performance under the contract, effective retroactive to June 2, 2003. FERC then issued an order on June 25, 2003, the "June 25 Order," that again commanded PMI's continued performance regardless of any contrary ruling by the bankruptcy court and the district court's temporary restraining order. By order dated June 30, 2003, the district court reversed itself and dismissed PMI's motion for preliminary injunction for lack of subject matter jurisdiction. On July 18, 2003, PMI appealed to the Second Circuit respecting the district court's refusal to enjoin FERC. On August 15, 2003, FERC issued orders denying rehearing of the June 25 Order and requiring PMI to continue to perform under the Standard Offer Services contract, the June 25 Order, together with the August 15 Orders, being the "Commission Orders." PMI filed a request for rehearing with FERC and a petition for review in the United States Court of Appeals for the District of Columbia Circuit in Case No. 03-1346 relating to the Commission Orders. On November 4, 2003, the parties reached a settlement under which the Second Circuit and D.C. Circuit litigation respecting the above matters will be dismissed, while preserving the parties' rights to litigate those matters which are before the U.S. District Court for Connecticut and FERC, as previously discussed. The settlement does not affect issues between CL&P and NRG Energy, Inc., related to station service, described hereafter, which will be separately arbitrated. The settlement is subject to regulatory and legal approvals, including approval from FERC and the bankruptcy court.

The State of New York and Erin M. Crotty, as Commissioner of the New York State Department of Environmental Conservation v. Niagara Mohawk Power Corporation et al., United States District Court for the Western District of New York, Civil Action No. 02-CV-002S

In January 2002, we and Niagara Mohawk Power Corporation, or "NiMo," were sued by the New York Department of Environmental Conservation, or "DEC," in federal court in New York. The complaint asserted that projects undertaken at our Huntley and Dunkirk plants by NiMo, the former owner of the facilities, required preconstruction permits pursuant to the Clean Air Act and that the failure to obtain these permits violated federal and state laws. In July, 2002, we filed a motion to dismiss. On March 27, 2003, the court dismissed the complaint against us with prejudice as to the federal claims and without prejudice as to the state claims. It is possible the state will appeal this dismissal to the Second Circuit Court of Appeals. In the meantime, on April 25, 2003, the state provided to us notice of intent to again sue us and various affiliates by filing a second amended complaint in this same action in the federal court in New York, asserting against us violations of operating permits and deficient operating permits at the Huntley and Dunkirk plants. We have moved to dismiss the second amended complaint, and that motion is now under advisement. If we do not succeed in our efforts to have the state's second amended complaint dismissed and the case ultimately is litigated to an unfavorable outcome that could not be addressed otherwise, we have estimated that the total investment that would be required to install pollution control devices could be as high as $300 million over a ten to twelve-year period. We also could be found responsible for payment of certain penalties and fines.

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

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

Huntley Power LLC, Dunkirk Power LLC and Oswego Power LLC

All three of these facilities have been issued Notices of Violation with respect to opacity exceedances. The above entities have been engaged in consent order negotiations with the DEC relative to opacity issues affecting all three facilities since the plants were acquired. It appears that by year-end, the parties may finalize the terms of a consent order which we expect to quantify the number of opacity exceedances at the three facilities through the second quarter of 2003 and set a cumulative penalty, presently anticipated to be approximately $1 million. In the event that the consent order negotiations prove unsuccessful, it is not known what relief the DEC will seek through an enforcement action and what the result of such action will be.

Huntley Power LLC

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

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

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

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

On October 8, 2002, a Stipulation and Order was filed in the Erie County Clerk's Office staying this action pending submission of some or all of the disputes in the action to the FERC. We cannot make an evaluation of the likelihood of an unfavorable outcome. The cumulative potential loss could exceed $35 million.

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

This is the companion action filed by Niagara Mohawk at FERC, similarly asserting that Niagara Mohawk is entitled to receive retail tariff amounts for electric service provided to the Huntley, Dunkirk and Oswego plants. On October 31, 2003, the FERC Trial Staff, a party to the proceedings, filed a reply brief in which they supported and agreed with each position taken by our facilities. In short, the staff argued that our facilities: (1) self-supply station power under the NYISO tariff (which took effect on April 1, 2003), in any month during which they produce more energy than they consume and, as such, should not be assessed a retail rate; (2) are connected only to transmission facilities and, as such, at most should only pay NiMo, a FERC-approved transmission rate; and (3) should be allowed to net consumption and output even if power is injected into the grid at a different point from which it is drawn off. The parties are currently engaged in settlement negotiations which, should they prove successful, could resolve both this FERC action and the above-referenced state court proceedings respecting amounts owing for electrical service provided to these three plants. At this stage of the proceedings, we cannot estimate the likelihood of success on this action. As noted above, the cumulative potential loss could exceed $35 million.

Pointe Coupee Parish Police Jury and Louisiana Generating, LLC v. United States Environmental Protection Agency and Christine Todd Whitman, Administrator, Adversary Proceeding No. 02-61021 on the docket of the United States Court of Appeals for the Fifth Circuit

On December 2, 2002, a Petition for Review was filed to appeal the EPA's approval of the Louisiana Department of Environmental Quality's, or "DEQ," revisions to the Baton Rouge State Implementation Plan, or "SIP." Pointe Coupee and our subsidiary, Louisiana Generating, object to the approval of SIP Section 4.2.1. Permitting NO_x Sources that purports to require DEQ to obtain offsets of major increases in emissions of NO_x, associated with major modifications of existing facilities or construction of new facilities both in the Baton Rouge Ozone Nonattainment Area and in four adjoining attainment parishes referred to as the Region of Influence, including Pointe Coupee Parish. The plaintiffs' challenge is based on DEQ's failure to comply with Administrative Procedures Act requirements related to rulemaking and EPA's regulations, which prohibit EPA from approving a SIP not prepared in accordance with state law. The action is currently stayed by the United States Fifth Circuit Court of Appeals in response to the filing of the Suggestion of Bankruptcy, and the parties have been engaged in settlement discussions in the meantime. EPA has just served notice that it intends to withdraw its approval of DEQ's Attainment Demonstration and will thereupon move to voluntarily dismiss the action as moot.

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

During 2000, DEQ issued a Part 70 Air Permit modification to Louisiana Generating to construct and operate two 240 MW natural gas-fired turbines. The Part 70 Air Permit set emissions limits for the criteria air pollutants, including NO_x, based on the application of Best Available Control Technology, or "BACT." The BACT limitation for NO_x was based on the guarantees of the manufacturer, Siemens-Westinghouse. Louisiana Generating sought an interim emissions limit to allow Siemens-Westinghouse time to install additional control equipment. To establish the interim limit, DEQ issued a Compliance Order and Notice of Potential Penalty, No. AE-CN-02-0022, on September 8, 2002, which is, in part, subject to the referenced administrative hearing. DEQ alleged that Louisiana Generating did not meet its NO_x emissions limit on certain days, did not conduct all opacity monitoring and did not complete all record keeping and certification requirements. Louisiana Generating intends to vigorously defend certain claims and any future penalty assessment, while also seeking an amendment of its limit for NO_x. An initial status conference has been held with the Administrative Law Judge and quarterly reports will be submitted to describe progress, including settlement and amendment of the limit. The extension of an amended BACT analysis has been granted until December 31, 2003. In addition, we may assert breach of warranty claims against the manufacturer. With respect to the administrative action described above, at this time we are unable to predict the eventual outcome of this matter or the potential loss contingencies, if any, to which we may be subject.

NRG Sterlington Power, LLC

During 2002, NRG Sterlington conducted a review of the Sterlington Power Facility's Part 70 Air Permit obtained by the facility's former owner and operator, Koch Power, Inc. Koch had outlined a plan to install eight 25 MW capacity turbines to reach a 200 MW capacity limit in the permit. Due to the inability of several units to reach their nameplate capacity, Koch determined that it would need additional units to reach the electric output target. In August 2000, NRG Sterlington acquired the remaining interests in the facility not originally held on a passive basis and sought the transfer of the Part 70 Air Permit along with a modification to incorporate two 17.5 MW turbines installed by Koch and to increase the total number of turbines to ten. The permit modification was issued February 13, 2002. During further review, NRG Sterlington determined that a ninth unit had been installed prior to issuance of the permit modification. In keeping with its environmental policy, it disclosed this matter to DEQ in April, 2002. NRG Sterlington provided to DEQ additional information during July 2002. A Consolidated Compliance Order & Notice of Potential Penalty, No. AE-CN-01-0393, was issued by DEQ on September 10, 2003, wherein DEQ formally alleged that NRG Sterlington did not complete all certification requirements, and installed a ninth unit prior to issuance of its permit modification. We met with DEQ on November 19, 2003 to discuss mitigating circumstances and we are about to submit a settlement proposal for DEQ's consideration. We are unable at this time to predict the eventual outcome or potential loss contingencies, if any, to which we may be subject.

FirstEnergy Arbitration Claim

On November 29, 2001, The Cleveland Electric Illuminating Company, The Toledo Edison Company and FirstEnergy Ventures, collectively referred to herein as the "Sellers," entered into Purchase and Sale Agreements with NRG Able Acquisition LLC, which were guaranteed by us, collectively referred to herein as the "Purchasers," for the purchase of certain power plants for approximately $1.5 billion. On August 8, 2002, the Sellers terminated the agreements and asserted that the Purchasers were liable for anticipatory breach of the Purchase and Sale Agreements on the grounds that they could not finance the purchases. On August 8, 2002, the Purchasers provided notice that they disagreed with the Sellers' assertion. After the Sellers filed a motion seeking a waiver of the automatic stay of Section 362(a) of the bankruptcy code respecting our then-existing involuntary bankruptcy, the parties stipulated to a waiver of that automatic stay, thereby allowing the Sellers to proceed with arbitration, but only for the purpose of liquidating the dollar amount of the Sellers' claim, referred to herein as the "FirstEnergy Arbitration Claim". The collection of any award, however, was to remain fully subject to our automatic stay. The parties thereafter obtained relief from stay respecting the present chapter 11 bankruptcy, so as to continue the arbitration. The parties have now reached a settlement which will liquidate the Sellers' bankruptcy claim at $396 million. The bankruptcy court has approved the settlement. In addition, FirstEnergy has sought approval from FERC to acquire shares of NRG. If FERC approves the application, FirstEnergy will receive distributions under the NRG plan of reorganization in the same manner as other unsecured creditors.

General Electric Company and Siemens Westinghouse Turbine Purchase Disputes

We and/or our affiliates have entered into several turbine purchase agreements with affiliates of General Electric Company, or “GE,” and Siemens Westinghouse Power Corporation, or “Siemens.” GE and Siemens have notified us that we are in default under certain of those contracts, terminated such contracts, and demanded that we pay the termination fees set forth in such contracts. GE’s claim amounts to $120 million and Siemens’ approximately $45 million in cumulative termination charges. We cannot estimate the likelihood of unfavorable outcomes in these disputes.

Itiquira Energetica, S.A.

Our indirectly controlled Brazilian project company, Itiquira Energetica S.A., the owner of a 156 MW hydro project in Brazil, is currently in arbitration with the former EPC contractor for the project, Inepar Industria e Construcoes, or “Inepar.” The dispute was commenced by Itiquira in September of 2002 and pertains to certain matters arising under the former EPC contract. Itiquira principally asserts that Inepar breached the contract and caused damages to Itiquira by (i) failing to meet milestones for substantial completion; (ii) failing to provide adequate resources to meet such milestones; (iii) failing to pay subcontractors amounts due; and (iv) being insolvent. Itiquira’s arbitration claim is for approximately U.S. $40 million. Inepar has asserted in the arbitration that Itiquira breached the contact and caused damages to Inepar by failing to recognize events of force majeure as grounds for excused delay and extensions of scope of services and material under the contract. Inepar’s damage claim is for approximately U.S. $10 million. The parties submitted their respective statements of claims, counterclaims and responses, and a preliminary arbitration hearing was held on March 21, 2003. In lieu of taking expert testimony at hearing, the court of arbitration has ordered an expert investigation process to cover technical and accounting issues. If the court of arbitration determines that the final report from the expert investigation process is inconclusive, it may then require expert testimony. We anticipate that the expert investigation process will not be completed sooner that February of 2004. We cannot estimate the likelihood of an unfavorable outcome in this dispute.

CFTC Trading Inquiry

On June 17, 2002, the CFTC served Xcel Energy, on behalf of its affiliates, including us and PMI, with a subpoena requesting certain information regarding “round trip” or “wash” trading and general trading practices in its investigation of several energy trading companies. The CFTC now appears focused on possible efforts by traders to manipulate indexes. The CFTC has requested additional related information from us and has subpoenaed to appear for testimony a number of our present or former employees. We have sought to cooperate with the CFTC and have submitted materials responsive to the CFTC’s requests. We cannot at this time predict the outcome or financial impact of this investigation.

NRG Energy Credit Defaults

We and various of our subsidiaries are in default under various of their credit facilities, financial instruments, construction agreements and other contracts, which have given rise to liens, claims and contingencies against them and may in the future give rise to additional liens, claims and contingencies against them. In addition, we and various of our subsidiaries have entered into guarantees, equity contribution agreements and other financial support agreements with respect to the obligations of their affiliates, which have given rise to liens, claims and contingencies against them and may in the future give rise to additional liens, claims and contingencies against the party or parties providing the financial support. We cannot predict the outcome or financial impact of these matters.

Additional Litigation

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

Disputed Claims Reserve

As part of the NRG plan of reorganization, we will retain a disputed claims reserve for the satisfaction of certain general unsecured claims that were disputed claims as of the effective date of the plan, principally the litigation matters described above. Under the terms of the plan, to the extent such claims are resolved after our emergence from bankruptcy, the claimants will be paid from the reserve on the same basis as if they had been paid out in the bankruptcy. That means that their claims will be reduced to approximately 50.7% of their face amount (i.e., an approximate recovery of $50.7 million on a $100 million allowed claim), and will be paid in pro rata distributions of cash, creditor notes and common stock. To the extent the aggregate amount of payouts of disputed claims ultimately exceeds the amount of the reserve, we must pay the shortfall from our other resources, subject to the face amount reduction and our ability to pay in pro rata distributions as described above. We believe the disputed claims reserve is sufficient, based on, among other things, the proofs of claim we received during the bankruptcy proceedings, and our analysis of the disputed claims.

THE BANKRUPTCY CASE

On May 14, 2003, NRG Energy, Inc. and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. Since the filing, we have continued to conduct our business and manage our properties as debtors in possession pursuant to sections 1107(a) and 1108 of the bankruptcy code. Our subsidiaries that own our international operations, and certain other subsidiaries, are not part of these chapter 11 cases or any of the subsequent bankruptcy filings. On November 24, 2003 the bankruptcy court entered an order confirming the NRG plan of reorganization, and we anticipate that the plan will become effective on or about December 5, 2003. On November 25, 2003, the bankruptcy court entered an order confirming the Northeast/South Central plan of reorganization and we anticipate that the plan will become effective in late 2003 or early 2004.

Events Leading to the Commencement of the Chapter 11 Filing

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

As a result of the downgrades, declining power prices, increasing fuel prices, the overall down-turn in the energy industry and the overall down-turn in the economy, we experienced severe financial difficulties. These difficulties caused us to, among other things, miss scheduled principal and interest payments due to our corporate lenders and bondholders, be required to prepay for fuel and other related delivery and transportation services and be required to provide performance collateral in certain instances. We also recorded asset impairment charges of approximately $3.1 billion during 2002, related to various operating projects as well as for projects that were under construction which we had stopped funding.

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

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

Two plans of reorganization have been filed in connection with our restructuring efforts. The first, filed on May 14, 2003, and referred to as the NRG plan of reorganization, relates to NRG Energy, Inc., and the other NRG Plan Debtors. The second plan, relating to our Northeast and South Central subsidiaries, which we refer to as the Northeast/ South Central plan of reorganization, was filed on September 17, 2003.

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

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

NRG Plan of Reorganization

The NRG plan of reorganization is the result of several months of intense negotiations among us, Xcel Energy and the two principal committees representing our creditor groups, which we refer to as the Global Steering Committee and the Noteholder Committee. A principal component of the NRG plan of reorganization is a settlement with Xcel Energy in which Xcel Energy has agreed to make a contribution consisting of cash (and, under certain circumstances, its stock) in the aggregate amount of up to $640 million to be paid in three separate installments following the effective date of the NRG plan of reorganization. The Xcel Energy settlement agreement resolves any and all claims existing between Xcel Energy and us and/or our creditors and, in exchange for the Xcel Energy contribution, Xcel Energy is receiving a complete release of claims from NRG and its creditors, except for a limited number of creditors who have preserved their claims as set forth in the confirmation order entered on November 24, 2003.

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

- an initial installment of $238 million in cash to be paid on February 22, 2004.
- a second installment of $50 million in cash or, at Xcel Energy's option, its common stock, on February 22, 2004.
- a third installment of $352 million in cash, which Xcel Energy will pay on April 30, 2004.

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

- Satisfy general unsecured claims by:
  - issuing $500 million in new 10% NRG Senior Unsecured Notes due 2010 to holders of certain classes of allowed general unsecured claims;
  - issuing new NRG common stock to holders of certain classes of allowed general unsecured claims; and
  - making cash payments in the amount of up to $540 million to holders of certain classes of allowed general unsecured claims;
- Satisfy certain secured claims by either (i) distributing the collateral to the security holder, (ii) selling the collateral and distributing the proceeds to the security holder or (iii) other mutually agreeable treatment; and
- Issue to Xcel Energy a $10 million non-amortizing promissory note which will (a) accrue interest at a rate of 3% per annum, and (b) mature 2.5 years after the effective date of the NRG plan of reorganization.

The NRG plan of reorganization is subject to certain conditions to effectiveness, including the following:

- the NRG plan of reorganization is declared effective by December 15, 2003;
- all actions, documents and agreements necessary to implement the NRG plan of reorganization have been effected or executed;
- all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions or documents that are necessary to implement the NRG plan of reorganization have been received;
- the confirmation order is entered, in full force and effect, is not reversed or modified and is not stayed or subject to a motion to stay and all appeal periods relating to the confirmation order are expired;
- all plan documents and any amendments thereto are in a form and substance satisfactory to us, Xcel Energy and the various creditors' committees; and

- the NRG plan of reorganization is not impermissibly amended, altered or modified from that approved by the confirmation order.

Northeast/ South Central Plan of Reorganization

The Northeast and South Central plan of reorganization was proposed on September 17, 2003 after we secured the necessary financing commitments. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central plan of reorganization. In connection with the order confirming the Northeast/ South Central plan of reorganization, the court entered a separate order which provides that the allowed amount of the bondholders' claims shall equal in the aggregate the sum of (i) $1.3 billion plus (ii) any accrued and unpaid interest at the applicable contract rates through the date of payment to the indenture trustee plus (iii) the reasonable fees, costs or expenses of the collateral agent and indenture trustee (other than reasonable professional fees incurred from October 1, 2003) plus (iv) $19.6 million, ratably, for each holder of bonds based upon the current outstanding principal amount of the bonds and irrespective of (a) the date of maturity of the bonds, (b) the interest rate applicable to such bonds and (c) the issuer of the bonds. The settlement further provides that the Northeast/ South Central debtors shall reimburse the informal committee of secured bondholders, the indenture trustee, the collateral agent, and two additional bondholder groups, for any reasonable professional fees, costs or expenses incurred from October 1, 2003 through January 31, 2004 up to a maximum amount of $2.5 million (including in such amount any post-October 1, 2003 fees already reimbursed), with the exception that the parties to the settlement reserved their respective rights with respect to any additional reasonable fees, costs or expenses incurred subsequent to November 25, 2003 related to matters not reasonably contemplated by the implementation of the settlement of the Northeast/ South Central plan of reorganization.

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

The Northeast/ South Central plan of reorganization is subject to certain conditions to effectiveness, including the following:

- all actions, documents and agreements necessary to implement the Northeast/ South Central Plan have been effected or executed;
- all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions or documents that are determined by the Northeast/ South Central Debtors to be necessary to implement the Plan have been received;
- the confirmation order is entered, in full force and effect, is not reversed or modified and is not stayed or subject to a motion to stay and all appeal periods relating to the confirmation order are expired;
- all plan documents and any amendments thereto are in a form and substance satisfactory to Northeast and South Central, the creditors committee and the global steering committee;
- the Northeast/ South Central plan of reorganization is not impermissibly amended, altered or modified from that approved by the confirmation order;
- the definitive documentation related to the Refinancing Transactions is in full force and effect; and
- certain other conditions relating to the Refinancing Transactions have been satisfied or waived.

Fresh-Start Reporting

Upon our emergence from bankruptcy, we will adopt fresh-start reporting. Under fresh-start reporting, our confirmed enterprise value will be allocated to our assets based on their respective fair values in conformity with the purchase method of accounting for business combinations. Any portion not attributed to specific tangible or identified intangible assets will be an indefinite-lived intangible asset referred to as “reorganization value in excess of value of identifiable assets” and reported as goodwill. Any excess of fair value of assets and liabilities over confirmed enterprise value will be allocated as a pro rata reduction of the amounts that otherwise would have been assigned to all of the assets except financial assets other than investments accounted for by the equity method, assets to be disposed of by sale, deferred tax assets, prepaid assets relating to pension or other postretirement benefit plans and any other current assets.

MANAGEMENT

Directors and Executive Officers Upon Emergence From Bankruptcy

The following table sets out the names and ages of each of the executive officers and directors of NRG Energy upon emergence from bankruptcy, followed by a description of their business experience during the past five years. All positions shown are with NRG Energy or its subsidiaries unless otherwise indicated. Unless otherwise indicated, each individual below is a U.S. citizen and the business address of each individual is: 901 Marquette Avenue, Suite 2300, Minneapolis, Minnesota 55402.

Name	Age	Position
David W. Crane	44	President, Chief Executive Officer and Director
John R. Boken	41	Chief Operating Officer
Scott J. Davido	42	Senior Vice President, General Counsel and Secretary
Ershel C. Redd Jr.	55	Senior Vice President, Commercial Operations
John P. Brewster	49	Vice President, Worldwide Operations
George P. Schaefer	53	Vice President and Treasurer
William T. Pieper	38	Vice President and Controller
Mark R. Patterson	51	Director
Ramon Betolaza	33	Director
Frank S. Plimpton	49	Director
John F. Chlebowski	58	Director
Lawrence S. Coben	45	Director
Stephen L. Cropper	53	Director
Herbert H. Tate	50	Director
Walter R. Young	59	Director
Thomas Weidemeyer	56	Director
Howard E. Cosgrove	60	Director

David W. Crane. Mr. Crane has been the President, Chief Executive Officer and a Director of NRG Energy since December 2003. Prior to joining NRG Energy, Mr. Crane served as Chief Executive Officer of International Power PLC, a UK-domiciled wholesale power generation company, from January 2003 to November 2003 and as Chief Operating Officer from March 2000 to December 2002. Mr. Crane was Senior Vice President — Global Power New York at Lehman Brothers Inc., an investment banking firm, from January 1999 to February 2000, where he was responsible for Lehman Brothers' global power business in emerging markets, and was Senior Vice President — Global Power Group, Asia (Hong Kong) at Lehman Brothers from June 1996 to January 1999.

John R. Boken. Mr. Boken has been Chief Operating Officer of NRG Energy since November 2003. He served as President and Chief Operating Officer of NRG Energy from May 2003 through November 2003 pursuant to a services contract between Leonard LoBiondo LLC and NRG Energy. Leonard LoBiondo is an entity that performs services in conjunction with Kroll Zolfo Cooper LLC on a contractual basis. From August 2002 through May 2003, Mr. Boken was an advisor to NRG Energy in his capacity as a Senior Director at Kroll Zolfo Cooper. Mr. Boken will serve as Chief Operating Officer until at least January 31, 2004. Prior to joining Kroll Zolfo Cooper in July 2003, Mr. Boken was a Partner in the Corporate Restructuring Practice at Arthur Andersen LLP, based in the firm's Los Angeles office.

Scott J. Davido. Mr. Davido has been Senior Vice President, General Counsel and Secretary at NRG Energy since October 2002. He served as Executive Vice President, Chief Financial Officer, Treasurer and Secretary of The Elder-Beerman Stores Corp., a department store retailer, from March 1999 to May 2002 and Senior Vice President, General Counsel from January 1998 to March 1999. Mr. Davido was a Partner, Business Practice Group with Jones, Day, Reavis & Pogue, a law firm, in Pittsburgh, Pennsylvania, from

January 1997 to December 1997 and an Associate, Business Practice Group from September 1987 to December 1996.

Ershel C. Redd, Jr. Mr. Redd has been Senior Vice President, Commercial Operations at NRG Energy since October 2002 and had been advising NRG Energy's senior management group with regards to power marketing operations since June 2002. Previously, Mr. Redd served as Vice President of Business Development for Xcel Energy Markets, Xcel Energy from January 2000 to October 2002. Prior to that time, he served as Vice President of e Prime, Inc., Xcel Energy from July 1999 to August 15, 2000. Mr. Redd served as President & Chief Operating Officer of Texas Ohio Gas, Inc., New Century Energy, Inc. (predecessor to Xcel Energy), from January 1997 to July 1999. He has more than 30 years of management experience in multiple areas of the energy industry.

John P. Brewster. Mr. Brewster has been Vice President, Worldwide Operations of NRG Energy since June 2002. From July 2001 through June 2002, Mr. Brewster served as Vice President, North American Operations of NRG Energy. From April 2000 through July 2001, he served as Vice President of Production for NRG Louisiana Generating Inc. From April 1995 to April 2000, Mr. Brewster served as Vice President of Production for Cajun Electric Power Cooperative.

George P. Schaefer. Mr. Schaefer has been Treasurer of NRG Energy since December 2002. Prior to December 2002, Mr. Schaefer served as Senior Vice President, Finance and Treasurer for PSEG Global, Inc., an operator of power plants and utilities, for one year, Vice President of Enron North America in its independent energy unit from June 2000 to April 2001 and Vice President and Treasurer of Reliant Energy International, an operator of power plants and utilities, from 1995 to June 2000. Mr. Schaefer was the Vice President, Business Development for Entergy Power Group from 1993 through 1995 and held the Senior Vice President, Structured Finance Group position with General Electric Capital Corporation from 1982 through 1993.

William T. Pieper. Mr. Pieper has been Vice President and Controller of NRG Energy since June 2001. He has also held the positions of Assistant Controller and Manager of International Accounting since joining NRG Energy in March 1995. Prior to joining NRG Energy, Mr. Pieper practiced as a Certified Public Accountant for six years with the firm of KPMG, a public accounting and auditing firm.

Mark R. Patterson. Mr. Patterson has been a director of NRG Energy since December 2003, pursuant to the NRG plan of reorganization. He has been the Chairman of MatlinPatterson since July 2002 and has supervisory and marketing responsibilities. Prior to July 2002, Mr. Patterson served as Vice Chairman of Credit Suisse First Boston Corporation, an investment banking firm, which he joined in March 1994. Mr. Patterson was a partner at Scully Brothers & Foss L.P., an investment and advisory boutique, from 1988 to 1990, Director at Salomon Brothers Inc., an investment banking firm, from 1983 to 1988 and Managing Director at Bankers Trust Company from 1977 to 1983, primarily focused on the leveraged finance, capital markets and private equity businesses. Mr. Patterson is also a director of Oxford Automotive and Compass Aerospace and a director and member of the audit committee of Eon Labs, Inc.

Ramon Betolaza. Mr. Betolaza has been a director of NRG Energy since December 2003, pursuant to the NRG plan of reorganization. He has been a partner of MatlinPatterson since July 2002. Prior to July 2002, Mr. Betolaza was a member of the Distressed Group (the predecessor to MatlinPatterson) of Credit Suisse First Boston Corporation, an investment banking firm, in London, which he joined in 1997. Mr. Betolaza is also a director of Opus Energy LLC and Polymer Group, Inc.

Frank S. Plimpton. Mr. Plimpton has been a director of NRG Energy since December 2003, pursuant to the NRG plan of reorganization. He has been a partner of MatlinPatterson since July 2002. Prior to July 2002, Mr. Plimpton was a member of the Distressed Group (the predecessor to MatlinPatterson) of Credit Suisse First Boston Corporation, an investment banking firm, which he joined in April 1998. Before joining CSFB, Mr. Plimpton held several positions as an investment manager for distressed situations, including Senior Vice President at Wexford Management LLC from 1996 to 1998, consultant to Pegasus Financial LLC from 1995 to 1996, and Director of Research at Smith Management Company from 1991 to 1995. Mr. Plimpton also held positions as an investment banker specializing in reorganizations, mergers and acquisitions, including Vice President at Salomon Brothers Inc. from 1989 to 1990 and First Vice President at PaineWebber Inc. from 1984 to 1989. Mr. Plimpton also practiced bankruptcy law for three years at Milbank, Tweed, Hadley & McCloy from 1981 to 1984. Mr. Plimpton is also a director of RailWorks Corporation and Oxford Automotive.

John F. Chlebowski. Mr. Chlebowski has been a director of NRG Energy since December 2003, pursuant to the NRG plan of reorganization. Mr. Chlebowski has served as the President and Chief Executive Officer of Lakeshore Operating Partners, LLC, a bulk liquid distribution firm, since March 2000. From July 1999 until March 2000, Mr. Chlebowski was a senior executive and cofounder of Lakeshore Liquids Operating Partners, LLC, a private venture firm in the bulk liquid distribution and logistics business, and from January 1998 until July 1999, he was a private investor and consultant in bulk liquid distribution. Prior to that, he was employed by GATX Terminals Corporation, a subsidiary of GATX Corporation, as President and Chief Executive Officer from 1994 until 1997. Mr. Chlebowski is a director of Laidlaw International Inc. and PRP-GP LLC.

Lawrence S. Coben. Mr. Coben has been a director of NRG Energy since December 2003, pursuant to the NRG plan of reorganization. He has been a Senior Principal of Sunrise Capital Partners, a private equity firm, since January 2001. From 1997 to 2001, Mr. Coben was an independent consultant. From 1994 to 1996, Mr. Coben was Chief Executive Officer of Bolivian Power Company. Mr. Coben is also a director of Prisma Energy.

Stephen L. Cropper. Mr. Cropper has been a director of NRG Energy since December 2003, pursuant to the NRG plan of reorganization. Mr. Cropper spent 25 years with The Williams Companies, an energy company, before retiring in 1998, as President and Chief Executive Officer of Williams Energy Services. Mr. Cropper is a director of Rental Car Finance Corporation, a subsidiary of Dollar Thrifty Automotive Group. He is a director and serves as the audit committee financial expert of Berry Petroleum Company. Mr. Cropper also serves as a director, chairman of the audit committee and member of the compensation committee of Sun Logistics Partners L.P. Mr. Cropper is a director and serves as the chairman of the compensation committee of QuikTrip Corporation. Mr. Cropper has also served as a director of Heritage Propane Partners, L.P., since April 2000 and is a member of the both the independent committee and the audit committee.

Herbert H. Tate. Mr. Tate has been a director of NRG Energy since December 2003, pursuant to the NRG plan of reorganization. He has been Of Counsel of Wolf & Samson P.C., a law firm, since September 2002. Mr. Tate was Research Professor of Energy Policy Studies at the New Jersey Institute of Technology from April 2001 to September 2002 and President of New Jersey Board of Public Utilities from 1994 to March 2001. Mr. Tate is also a director of IDT Solutions and Winstar Telecommunications.

Walter R. Young. Mr. Young has been a director of NRG Energy since December 2003, pursuant to the NRG plan of reorganization. Mr. Young was Chairman, Chief Executive Officer and President of Champion Enterprises, Inc., an assembler and manufacturer of manufactured homes, from May 1990 to June 2003. Mr. Young has held senior management positions with The Henley Group, The Budd Company and BFGoodrich.

Thomas H. Weidemeyer. Mr. Weidemeyer has been a director of NRG Energy since December 2003, pursuant to the NRG plan of reorganization. He has been Senior Vice President and Chief Operating Officer of United Parcel Service, Inc., the world's largest transportation company, since January 2001 and President of UPS Airlines since June 1994. Mr. Weidemeyer joined UPS in 1972 in National Personnel. Mr. Weidemeyer became Manager of the Americas International Operation in 1989, and in that capacity directed the development of the UPS delivery network throughout Central and South America. In 1990, Mr. Weidemeyer became Vice President and Airline Manager of UPS Airlines and in 1994 was elected its President and Chief Operating Officer. Mr. Weidemeyer became Manager of the Air Group and a member of the Management Committee that same year, and he became Chief Operating Officer of United Parcel Service, Inc. in 2001. Mr. Weidemeyer is a director of United Parcel Service, Inc.

Howard E. Cosgrove. Mr. Cosgrove has been a director of NRG Energy since December 2003, pursuant to the NRG plan of reorganization. He was Chairman and Chief Executive Officer of Conectiv and its predecessor Delmarva Power and Light from December 1992 to August 2002. Prior to December 1992, Mr. Cosgrove held various positions with Delmarva Power and Light including Chief Operating Officer and Chief Financial Officer. Mr. Cosgrove serves as Chairman of the Board of Trustees at University of Delaware, and he also serves on the board of Henlopen Mutual Fund.

There are no family relationships between any of our officers and directors, and there is no arrangement or understanding between any of the executive officers and any other person pursuant to which he was selected as an officer. Each of our officers serves at the discretion of the board of directors.

Board of Directors Upon Emergence From Bankruptcy

Upon emergence from bankruptcy, our board of directors will initially consist of David W. Crane, our new President and Chief Executive Officer, and ten other individuals; three of whom have been designated by MatlinPaterson and seven of whom we expect will be independent. Each director will be deemed elected or appointed, as the case may be, pursuant to the confirmation order but will not take office until the effective date. Those directors and officers not continuing in office will be deemed removed from office as of the effective date pursuant to the confirmation order. As the terms of the directors expire, the holders of NRG common stock will be entitled to vote to fill vacancies in accordance with the new certificate of incorporation and by-laws to be adopted in connection with the NRG plan of reorganization. The board of directors, collectively, including any required committee thereof, will comply with any qualifications, experience or independence requirements of applicable law, including the Sarbanes-Oxley Act of 2002 and the rules then in effect of any stock exchange or quotation system on which NRG common stock is listed or anticipated to be listed.

Board members will be divided into three classes, with each class consisting, as nearly as possible, of an equal number of directors serving staggered terms. Approximately one-third of the board will be elected each year, and, once elected, directors may only be removed from the board for cause. The provision for a classified board could prevent a party who acquires control of a majority of our outstanding voting stock from obtaining control of the board of directors until the second annual stockholders meeting following the date the acquiror obtains the controlling stock interest. The classified board provision could have the effect of discouraging a potential acquiror from making a tender offer or otherwise attempting to obtain control of NRG Energy and could increase the likelihood that incumbent directors will retain their positions.

Compensation of Executive Officers

The following tables set forth cash and non-cash compensation for each of the fiscal years ended December 31, 2000, 2001 and 2002 for the individuals who served as our Chief Executive Officer and Chief Operating Officer during 2002 and each of the four next most highly compensated executive officers, which we refer to collectively as the “Named Executive Officers.”

Summary Compensation Table

					Long-Term Compensation			
					Awards		Payouts	
		Annual Compensation						
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation ($)	Restricted Stock Awards ($)	Number of Securities Underlying Options and SARs[6] (#)	LTIP Payouts ($)	All Other Compensation ($)
Wayne Brunetti(1)	2002	—	—	—	—	—	—	—
Former Chairman, President	2001	—	—	—	—	—	—	—
and Chief Executive Officer	2000	—	—	—	—	—	—	—
David H. Peterson(2)	2002	208,334	—	38,647(3)	—	—	—	1,754,424(5)
Former Chairman, President	2001	491,670	750,000	13,689	—	265,500	—	9,902
and Chief Executive Officer	2000	397,340	474,000	28,678	—	120,000	1,212,067	22,923
John Brewster	2002	189,503	—	—	—	—	—	11,253(7)
Vice President — Worldwide	2001	155,317	102,552	5,000	—	7,000	—	4,660
Operations	2000	91,741	24,343	—	—	800	—	157
William Pieper	2002	158,769	—	—	—	—	—	9,706(10)
Vice President & Controller	2001	138,302	153,994	—	—	41,000	—	—
	2000	127,554	74,612	—	—	1,414		2,976
Renee Sass(4)	2002	192,215	—	24,299	—	—	—	51,428(8)
Former Vice President	2001	175,004	203,500	27,270	—	35,000	—	—
Strategic Planning and	2000	147,672	79,685	—	—	1,722		2,882
Asset Management								
Craig Mataczynski(9)	2002	160,006	—	11,624(11)	—	—	—	95,386(12)
Former Senior Vice President	2001	316,680	321,038	7,752	—	105,000	—	8,125
North America	2000	278,340	276,500	6,303	—	60,000	186,250	3,059

(1) Mr. Brunetti is Chairman and Chief Executive Officer of Xcel Energy, NRG Energy’s parent company prior to emergence from bankruptcy. He was not compensated by NRG Energy for service in his capacity as Chairman and Chief Executive Officer of Xcel Energy.

(2) Mr. Peterson’s employment with NRG Energy terminated on May 31, 2002.

(3) Includes fringe benefits and fringe benefit tax gross-up.

(4) Ms. Sass’s employment with NRG Energy terminated on December 18, 2002.

(5) Includes paid time off (PTO) payout, 401(k) match, fringe benefit tax gross-up, severance payment equal to two months’ salary and pension make-up payment.

(6) Represents options to purchase Xcel Energy Common Stock.

(7) Includes 401(k) match.

(8) Includes severance pay, 401(k) match and PTO payout.

(9) Mr. Mataczynski’s employment with NRG Energy terminated on June 28, 2002.

(10) Represents 401(k) match.

(11) Includes fringe benefits and fringe benefit tax gross-up.

(12) Includes severance pay, 401(k) match and PTO payout.

Options and Stock Appreciation Rights (SARs)

We did not use stock options and SARs for executive compensation purposes in 2002.

The following table indicates for each of the Named Executive Officers the number and value of all exercisable and unexercisable options and SARs held by the Named Executive Officers as of December 31, 2002.

Aggregated Option/SAR Exercises in Last Fiscal Year

and Fiscal Year End Option/SAR Values

Name	Shares Acquired on Exercise(#)(1)	Value Realized($)	Number of Securities Underlying Unexercised Options/SARs at Fiscal Year End(#) Exercisable/Unexercisable	Value of Unexercised In-the-Money Options/SARs at Fiscal Year End($) Exercisable/Unexercisable(2)
David H. Peterson	94,798	$789,451	180,389/227,915	$(1,870,207)/$(1,851,016)
Craig A. Mataczynski	—	—	56,372/48,396	$(686,336)/$(1,043,922)
William T. Pieper	2,674	$ 28,738	6,307/17,375	$(8,825)/$(14,922)
Renee Sass	3,684	$ 50,192	17,086/17,702	$(161,162)/$(387,867)
John P. Brewster	—	—	975/2,925	$(1,900)/$(5,700)

(1) Shares acquired on exercise are stated at the Xcel Energy conversion value.

(2) Option values were calculated based on a $11.00 closing price of Xcel Energy Common Stock at December 31, 2002.

Long-Term Incentive Plan

Pursuant to our plan of reorganization, the NRG Energy, Inc. Long-Term Incentive Plan will become effective upon our emergence from bankruptcy. The long-term incentive plan will provide 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 will be eligible to receive grants under the long-term incentive plan. The purpose of the long-term inventive plan is to promote our long-term growth and profitability by providing these individuals with incentives to maximize stockholder value and otherwise contribute to our success and to enable us to attract, retain and reward the best available persons for positions of responsibility.

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

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

The following is a summary of the material terms of the long-term incentive plan, but does not include all of the provisions of the plan. This description is not intended to be exhaustive and is qualified in its entirety by reference to the provisions that will be contained in the long-term incentive 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 will be eligible to receive grants under the long-term incentive plan. In each case, the compensation committee will select the actual grantees.

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

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

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

- in cash;
- by delivery of shares of common stock with a fair market value equal to the exercise price;
- by means of any cashless exercise procedure approved by the compensation committee; or
- by any combination of the foregoing.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Pension Plan Tables

We currently participate in Xcel Energy's noncontributory defined benefit pension plan. Such plan covers substantially all of our employees. Effective January 1, 2004, we anticipate that we will establish two stand-alone defined benefit pension plans that will substantially replicate the current plan design. The first plan will provide coverage for our bargaining employees and the second plan will provide coverage for the non-bargaining employees. As of emergence, the pension benefit formula that applies to the Named Executive Officers will be a pension equity program.

Under the pension equity program applicable to certain of the Named Executive Officers, the formula for determining the pension benefit is average compensation times credited years of service times 10%. The annual compensation used to calculate average compensation is base salary for the year plus bonus compensation paid in that same year. There is no maximum on the number of years of service used to determine the pension benefit. The benefit amounts under the pension equity program are computed in the form of a lump sum.

The following table illustrates the approximate retirement benefits payable to employees retiring at the normal retirement age of 65 years under the traditional program applicable to certain of the Named Executive Officers:

Average Compensation (Last 4 Years)	Estimated Annual Benefits for Years of Service Indicated Years of Service					
	5	10	15	20	25	30
$50,000	$ 4,500	$ 9,000	$ 13,500	$ 19,000	$ 25,000	$ 31,500
100,000	8,500	17,000	25,500	35,000	45,500	56,000
150,000	12,500	25,000	38,000	51,500	66,000	80,500
200,000	16,500	33,500	50,000	68,000	86,500	105,000
250,000	21,000	41,500	62,500	84,000	107,000	129,500
300,000	25,000	49,500	74,500	100,500	127,500	154,000
350,000	29,000	58,000	87,000	117,000	147,500	178,500
400,000	33,000	56,000	99,000	133,000	168,000	203,000
450,000	37,000	74,000	111,500	149,500	188,500	227,500
500,000	41,000	82,500	123,500	166,000	209,000	252,000
550,000	45,500	90,500	136,000	182,000	229,500	276,500
600,000	49,500	98,500	148,000	198,500	250,000	301,000
650,000	53,500	107,000	160,500	215,000	270,000	325,500
700,000	57,500	115,000	172,500	231,000	290,500	350,000
750,000	61,500	123,000	185,000	247,500	311,000	374,500
800,000	65,500	131,500	197,000	264,000	331,500	399,000
850,000	70,000	139,500	209,500	280,000	352,000	423,500
900,000	74,000	147,500	221,500	296,500	372,500	448,000
950,000	78,000	156,000	234,000	313,000	392,500	472,500

Average Compensation (Last 4 Years)	Estimated Annual Benefits for Years of Service Indicated Years of Service					
	5	10	15	20	25	30
1,000,000	82,000	164,000	246,000	329,000	413,000	497,000
1,050,000	86,000	172,000	258,500	345,500	433,500	521,500
1,100,000	90,000	180,500	270,500	362,000	454,000	546,000
1,150,000	94,500	188,500	283,000	378,000	474,500	570,500
1,200,000	98,500	196,500	295,000	394,500	495,000	595,000

The following table illustrates the approximate retirement benefits payable to employees retiring at the normal retirement age of 65 years under the pension equity program applicable to certain of the Named Executive Officers if paid in the form of a straight-line annuity:

Average Compensation (Last 4 Years)	Estimated Annual Benefits for Years of Service Indicated Years of Service					
	5	10	15	20	25	30
$50,000	$ 3,500	$ 7,000	$ 11,000	$ 15,500	$ 20,500	$ 26,500
100,000	6,000	12,000	18,500	25,500	33,000	41,500
150,000	8,500	17,000	26,000	35,500	46,000	57,000
200,000	11,000	22,000	33,500	45,500	58,500	72,000
250,000	13,500	27,000	41,500	56,000	71,000	87,000
300,000	16,000	32,500	49,000	66,000	83,500	102,500
350,000	18,500	37,500	56,500	76,000	96,500	117,500
400,000	21,000	42,500	64,000	86,000	109,000	133,000
450,000	23,500	47,500	71,500	96,500	121,500	148,000
500,000	26,000	52,500	79,500	106,500	134,500	163,000
550,000	28,500	57,500	87,000	116,500	147,000	178,500
600,000	31,000	62,500	94,500	127,000	159,500	193,500
650,000	33,500	67,500	102,000	137,000	172,500	208,500
700,000	36,000	73,000	109,500	147,000	185,000	224,000
750,000	39,000	78,000	117,000	157,000	197,500	239,000
800,000	41,500	83,000	125,000	167,500	210,500	254,500
850,000	44,000	88,000	132,500	177,500	223,000	269,500
900,000	46,500	93,000	140,000	187,500	235,500	284,500
950,000	49,000	98,000	147,500	197,500	248,500	300,000
1,000,000	51,500	103,000	155,000	208,000	261,000	315,000
1,050,000	54,000	108,000	163,000	218,000	273,500	330,500
1,100,000	56,500	113,500	170,500	228,000	286,500	345,500
1,150,000	59,000	118,500	178,000	238,000	299,000	360,500
1,200,000	61,500	123,500	185,500	248,500	311,500	376,000

The approximate credited years of service as of December 31, 2002, for the Named Executive Officers were as follows:

	Years
Mr. Peterson	38.33
Mr. Mataczynski	20.00
Mr. Pieper	7.67
Mrs. Sass	11.50
Mr. Brewster	2.75

Employment Agreements

David W. Crane

David W. Crane is party to an employment agreement with us dated as of November 10, 2003. The employment agreement provides that Mr. Crane will serve as President and Chief Executive Officer of NRG Energy until December 1, 2006, unless otherwise terminated pursuant to the terms of the agreement.

The employment agreement provides for an annual base salary of $875,000 through December 31, 2004. For each one-year period thereafter, Mr. Crane's base salary will be determined by NRG Energy's board of directors. In addition to his base salary, Mr. Crane received a one-time signing bonus of $1.75 million upon acceptance of the employment agreement by the bankruptcy court (provided, however, that in the event Mr. Crane leaves NRG Energy within one year of receiving the signing bonus, Mr. Crane must repay a pro rata portion of the signing bonus based on the number of days remaining in such one-year period). The bankruptcy court approved the employment agreement on November 21, 2003. In addition, Mr. Crane is entitled to an annual bonus of up to 100% of his base salary based upon NRG Energy achieving certain performance criteria as determined by the board of directors (provided that Mr. Crane will not receive less than 75% of his base salary for fiscal year 2004). Further, Mr. Crane may be entitled to an annual "stretch bonus" of up to 50% of his base salary upon NRG's achievement of certain criteria determined by the board of directors. In the event the effective date under the plan of reorganization has not occurred prior to June 30, 2004 and Mr. Crane elects to terminate the employment agreement on or prior to July 31, 2004 (or his employment is terminated prior to such date by NRG Energy "without cause" or by Mr. Crane for "good reason"), he will be entitled to a $3.5 million payment from us and will not be obligated to repay any portion of the signing bonus.

In addition to salary and bonuses, we will provide Mr. Crane with a combination of restricted stock and stock options pursuant to our Long-Term Incentive Plan upon emergence from bankruptcy. The aggregate value of such restricted stock and stock options is limited to $12.5 million and shall vest at a time and pursuant to the vesting provisions set forth in separate stock subscription and stock option agreements. Mr. Crane is also entitled to health, welfare and retirement benefits, term life insurance of $7.75 million, five weeks paid vacation, coverage under our director and officer liability insurance coverage and reimbursement of moving expenses. In addition, we have agreed to use reasonable efforts to nominate and cause the election of Mr. Crane to the board of directors.

In the event Mr. Crane's employment with us is terminated by NRG Energy "without cause" or by Mr. Crane for "good reason" (including a reduction in his base salary) after the effective date of the NRG plan of reorganization occurs, Mr. Crane will be entitled to:

- two times his base salary (without regard for any reduction in base salary);
- 50% of the target annual bonus (75% in 2004), pro-rated for the number of days he was employed with the company in the year of termination;
- immediate vesting of all restricted stock and stock options;
- continuing medical and dental coverage for six months plus a lump sum payment equal to the cost under COBRA of family coverage under NRG Energy's health plans for 18 months; and
- earned but unpaid base salary, bonuses, deferred compensation, vacation pay and retirement benefits.

In the event Mr. Crane's employment with NRG Energy is terminated by us for cause or by Mr. Crane without good reason, Mr. Crane will be entitled to:

- earned but unpaid base salary, bonuses, deferred compensation, vacation pay and retirement benefits; and
- treatment of restricted stock and stock options in accordance with the terms of the stock subscription and stock option agreements.

In the event Mr. Crane's employment with NRG Energy is terminated due to his death or disability, Mr. Crane (or his estate) will be entitled to:

- 50% of the target annual bonus (75% in 2004), pro-rated for the number of days he was employed with the company in the year of termination;
- pro rata vesting of all restricted stock and stock options; and
- earned but unpaid base salary, bonuses, deferred compensation, vacation pay and retirement benefits.

In the event that the payments under Mr. Crane's employment agreement subject him to an excise tax under Section 4999 of the Internal Revenue Code, he will be entitled to a "gross-up payment" so that the net amount received by Mr. Crane after imposition of the excise tax equals the amount he would have received under the employment agreement absent the imposition of the excise tax. In addition, under the employment agreement, we have agreed to indemnify Mr. Crane against any claims arising as a result of his position with us to the maximum extent permitted by law.

Under the employment agreement, Mr. Crane agrees not to divulge confidential information or, during and for a period of one year after the termination of the employment agreement, compete with, or solicit the customers or employees of, NRG Energy.

Scott J. Davido

Scott J. Davido is party to an Amended and Restated Key Executive Retention, Restructuring Bonus and Severance Agreement dated as of July 1, 2003. The agreement (i) sets Mr. Davido's initial base salary at $500,000 (which will be reduced to $300,000 upon the Effective Date (as defined in the NRG plan of reorganization)), (ii) provides for a "Restructuring Bonus" upon the Effective Date and (iii) provides for certain severance benefits upon a termination of Mr. Davido's employment.

Upon the occurrence of the Effective Date (provided the Effective Date occurs by the date specified in the NRG plan of reorganization), provided Mr. Davido is still employed with NRG Energy (or has been terminated without cause or has left the employ of NRG Energy for good reason), he will be entitled to a lump sum amount equal to 1.5 times his base salary. In addition, Mr. Davido will be entitled to the following severance benefits if he is terminated without cause or leaves the employ of NRG Energy for good reason (in a lump sum payment or pro rata over thirty months, at the discretion of NRG Energy):

- Two times the sum of (i) his base salary and (ii) the greater of his average annual bonus over the last two years and his targeted bonus for the year in which he is terminated or leaves the employ of NRG Energy;
- The pro rata portion of his unpaid targeted annual incentive under a plan in effect at NRG Energy;
- A net cash payment (lump sum) equal to the COBRA premiums in effect for dental and health coverage as of the termination of employment for a period of 18 months; and
- A cash payment for earned but untaken vacation and time-off.

In the event that the payments under Mr. Davido's Amended and Restated Key Executive Retention, Restructuring Bonus and Severance Agreement subject him to an excise tax under Section 4999 of the Internal Revenue Code, he will be entitled to a "gross-up payment" so that the net amount received by Mr. Davido after imposition of the excise tax equals the amount he would have received under the agreement absent the imposition of the excise tax.

Under the agreement, Mr. Davido agrees not to compete with, or solicit the customers or employees of, NRG Energy for a period of one year. Further, Mr. Davido agrees not to disparage NRG Energy during or subsequent to his employment with NRG Energy. The agreement is subject to the approval of the bankruptcy court and NRG Energy has agreed to move the bankruptcy court (at Mr. Davido's request) to ensure compliance with the agreement.

Ershel Redd

Ershel Redd is party to a severance agreement with NRG Energy dated as of January 30, 2003. Under the agreement, Mr. Redd is entitled to severance benefits equivalent to those under the Xcel Energy Business Unit Vice President Severance Plan. Specifically, if (i) Mr. Redd's employment is terminated without cause, (ii) his position is eliminated without a comparable position being offered, (iii) his salary is reduced by more than 10% (and he subsequently voluntarily terminates his employment) or (iv) he is required to relocate (and he subsequently voluntarily terminates his employment), then Mr. Redd is entitled to lump-sum and continuing severance benefits during the "severance period" (18 months after employment termination). Further, all of the obligations under Mr. Redd's severance plan are guaranteed by Xcel Energy.

The lump-sum severance benefit is equal to the aggregate of: (i) unpaid annual salary through the date of termination and a pro rata share of Mr. Redd's target annual incentive; (ii) 1.5 times the sum of Mr. Redd's salary and target annual incentive; (iii) certain retirement benefits Mr. Redd would have earned had he been employed during the severance period; and (iv) certain contributions that NRG Energy would have made to Mr. Redd's defined contribution and supplemental executive savings plans. The continuing benefits include: (i) medical, dental, vision and life insurance; (ii) outplacement services (up to $15,000); (iii) financial counseling; and (iv) his "flexible prerequisite allowance." In the event that payments under Mr. Redd's severance agreement would subject him to an excise tax under Section 4999 of the Internal Revenue Code, those payments will be cut back to one dollar below the maximum value of all payments that he can receive under the severance agreement without the payments being subject to the excise tax.

William T. Pieper

William T. Pieper is party to a letter agreement with NRG Energy dated as of March 1, 2003 which provides Mr. Pieper certain severance benefits in the event his employment with NRG Energy is terminated. In the event that Mr. Pieper's employment is terminated without cause or Mr. Pieper resigns for good reason, he is entitled to (i) 1.5 times his annual base salary and 45% of his target bonus, in the form of salary continuation or in a single lump sum payment and (ii) a lump sum payment for all costs associated with health benefits under COBRA for a period of 12 months.

George Schaefer

George Schaefer is party to a letter agreement with NRG Energy dated as of December 18, 2002 which provides Mr. Schaefer certain severance benefits in the event his employment with NRG Energy is terminated. Specifically, in the event Mr. Schaefer's employment is terminated without cause or Mr. Schaefer resigns for good reason, he is entitled to a lump sum payment equal to his annual base salary and a lump sum payment for all costs associated with health benefits under COBRA for a period of twelve months.

John P. Brewster

John P. Brewster is party to a letter agreement with NRG Energy dated as of July 23, 2003 which provides Mr. Brewster certain severance benefits in the even his employment with NRG Energy is terminated. In the event that Mr. Brewster's employment is terminated without cause or Mr. Brewster resigns for good reason, he is entitled to (i) 1.5 times his annual base salary, in the form of salary continuation or in a single lump sum payment and (ii) a lump sum payment for all costs associated with health benefits under COBRA for a period of 12 months.

Director Compensation

Compensation arrangements for our directors upon emergence from bankruptcy have not been finalized.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Stockholders Registration Rights Agreement

Upon emergence from bankruptcy, we and certain holders of our common stock will enter into a registration rights agreement. Under the registration rights agreement, a holder or group of holders that owns 10% or more of our outstanding common stock has the right to require us to register any or all of their shares of common stock on the appropriate registration form as prescribed by the SEC under the Securities Act, at our expense. An initiating holder, which holds 10% or more of our outstanding common stock, may make an initiating request on up to two occasions, and an initiating holder group, which collectively owns 10% or more of our outstanding common stock, may make an initiating request on one occasion only, but we will not be required to effect more than a total of three registrations pursuant to this requirement. We are required to effect a registration at the request of an initiating holder only if the disposition of our common stock is conducted through an underwritten offering on a "firm commitment" basis, or if the initiating holder is a 10% holder or an "affiliate" of ours for purposes of Rule 144 under the Securities Act. Once a registration statement filed pursuant to this agreement has been declared effective, we will not be required to effect another registration until a period of 180 days has elapsed from the date on which the previous registration statement ceases to be effective. We are not required to effect any registration at the request of an initiating holder unless at least 10% of the shares of registrable common stock outstanding at the time of the request are to be included in the registration statement. We may postpone the filing of any registration statement on up to three occasions and for no more than a total of 90 days in any calendar year if we reasonably believe that the filing would adversely affect a pending or proposed public offering of our securities, a material financing, or a material acquisition, merger, recapitalization, consolidation, reorganization or similar transaction.

In addition, all holders of registrable common stock are entitled to request the inclusion of any shares of their registrable common stock in any registration statement at our expense whenever we propose to register any of our equity securities under the Securities Act. The right to request inclusion of shares does not apply to a registration on Form S-4 or S-8, or to a registration statement to be filed in connection with an exchange offer or offering of securities solely to our existing stockholders.

In connection with all registrations pursuant to the registration rights agreement, we have agreed to indemnify the holders of registrable common stock against liabilities relating to the registration, including liabilities under the Securities Act. In addition, each holder of registrable common stock has agreed not to sell any of our equity securities for a period beginning ten days prior to the date on which the registration statement for our first underwritten registered public offering of common stock becomes effective and continuing for a period of 180 days thereafter, except as part of that initial public offering. Each holder of registrable common stock has agreed not to sell any of our equity securities for a period beginning ten days prior to the date on which any subsequent registration statement becomes effective and continuing for a period of 90 days thereafter, except as part of that registered public offering. Our obligations under the registration rights agreement will terminate on the fourth anniversary of the effective date of the NRG plan of reorganization, but if on that fourth anniversary any holder of registrable common stock owns 10% or more of our outstanding common stock, then our obligations will continue only with respect to that holder and will terminate when that holder ceases to be a 10% holder.

Registration Rights Agreement for Plan Notes

The following is a summary of the Plan Notes registration rights agreement. The Plan Notes registration rights agreement is currently being negotiated. As a result, the final terms of such agreement may be different from those summarized below and such differences may be significant.

Upon emergence from bankruptcy, we and certain holders of our Plan Notes will enter into a registration rights agreement. Under the registration rights agreement, we will register, at our expense all of the registrable Plan Notes for an offering to be made on a delayed or continuous basis pursuant to Rule 415 of the Securities Act. We will use our reasonable best efforts to cause the registration statement to be filed on the date that is the earlier of (a) 30 days after we become eligible to use registration statements on Form S-3, and (b) May 1, 2004. When we effect a registration pursuant to the Plan Notes registration rights agreement, no securities other than the registrable Plan Notes will be included in the registration statement. We may postpone the filing of any registration statement on up to three occasions and for no more than a total of 180 days in any calendar year if we reasonably believe that the filing would adversely affect a pending or proposed public offering of our securities, a material financing, or a material acquisition, merger, recapitalization, consolidation, reorganization or similar transaction.

In connection with any registration statement filed pursuant to the Plan Notes registration rights agreement, we have agreed to indemnify the holders of registrable Plan Notes against liabilities relating to the registration, including liabilities under the Securities Act.

PRINCIPAL STOCKHOLDERS

Upon consummation of the NRG plan of reorganization, new common stock of NRG Energy, Inc. will be distributed pursuant to such plan to the holders of certain classes of claims, as more fully described in "The Bankruptcy Case—NRG Plan of Reorganization."

As of the date of this report, the beneficial ownership of our new common stock following consummation of the NRG plan of reorganization cannot be calculated. Certain of our prepetition creditors will be sharing in our equity on a pro rata basis, but the exact amount of each creditor's claim as of the distribution date is not known because there are unliquidated claims as well as claims in amounts to which there may be objections. In addition, holders of claims could elect to alter the composition of their distribution of cash, Plan Notes and NRG common stock that they would receive pursuant to the plan of reorganization. The aggregate reallocation of cash, Plan Notes and NRG common stock cannot be determined at this time.

It is currently estimated that upon our emergence from bankruptcy, our prepetition noteholders and lenders will collectively receive in excess of 80% of our outstanding common stock. It is estimated that MatlinPaterson will beneficially own approximately 20% of our outstanding common stock and, upon receipt of approval from FERC to acquire shares of NRG, First Energy will beneficially own approximately 6.5% of our common stock. In addition, because of their affiliation with MatlinPatterson, Messrs. Patterson, Betolaza and Plimpton may be deemed to beneficially own the shares held by MatlinPatterson. A person generally "beneficially owns" shares if he or she has the right to vote those shares or dispose of them. More than one person may be considered to beneficially own the same shares.

DESCRIPTION OF CERTAIN INDEBTEDNESS

Plan Notes

The following is a summary of the Plan Notes indenture. The Plan Notes indenture is currently being negotiated. As a result, the final terms of such agreement may be different from those summarized below.

Pursuant to the NRG plan of reorganization, we will issue up to $500 million of 10.0% Senior Notes due 2010, or the “Plan Notes,” to certain holders of unsecured claims against NRG Energy and PMI. The Plan Notes will accrue interest commencing on the effective date at a rate of 10.0% per annum and will be payable semiannually in cash. The Plan Notes will mature on the seventh anniversary of the effective date. The Plan Notes are unsecured obligations of NRG Energy, equal in right of payment with all of our other unsecured and unsubordinated indebtedness.

The Plan Notes are redeemable at our option, in whole at any time or in part from time to time, upon not less than 30 nor more than 60 days’ notice to each holder. Redemption prices will depend on the date at which the notes are redeemed.

On or prior to a date to be determined (currently contemplated to be the first anniversary of the issuance of the Plan Notes), we will have the right to redeem the Plan Notes at a redemption price equal to 100% of the original principal amount of the Plan Notes plus accrued and unpaid interest thereon. In addition, at any time and from time to time, prior to a date to be determined after negotiation, we may redeem up to a maximum of 35% of the original aggregate principal amount of the Plan Notes with the net cash proceeds of an offering of our common stock, at a price equal to 100% of that principal amount of the Plan Notes to be redeemed, plus accrued and unpaid interest thereon, but only if at least 65% of the original aggregate principal amount of the Plan Notes will remain outstanding after the redemption. Finally, we may choose to redeem the notes at any time following a date to be determined after negotiation and prior to a date to be determined after negotiation at a price equal to the greater of (i) 100% of the principal amount of the Plan Notes to be redeemed, plus accrued and unpaid interest thereon, and (ii) the sum of the present values of (a) the redemption price equal to 105% of the principal amount of the Plan Notes and (b) any interest due on the Plan Notes through a date to be determined after negotiation, in each case discounted at the rate that is the annual rate equal to the yield to maturity, compounded semi-annually, of a selected comparable treasury issue, assuming a yield for the comparable treasury issue on the third business day preceding the redemption date, as set forth under the heading which represents the average for the immediately preceding week, appearing in the most recently published statistical release designated “H.15(519)” published by the Board of Governors of the Federal Reserve System for the particular redemption date plus 0.5% plus accrued and unpaid interest, if any.

If a change of control occurs, we will be required to offer to purchase the Plan Notes at 101% of the aggregate principal amount of the Plan Notes, plus accrued and unpaid interest, if any, to the date of purchase. The Plan Notes indenture contains covenants which, among other things, limit:

- restricted payments,
- transactions with affiliates,
- indebtedness,
- dividend and other payment restrictions affecting subsidiaries,
- asset sales,
- issuance of preferred stock of subsidiaries and
- liens.

The Plan Notes indenture includes various events of default customary for those types of agreements, such as failure to pay principal and interest when due on the Plan Notes, cross defaults on other indebtedness and certain events of bankruptcy, insolvency and reorganization.

In the event that disputed claims that become allowed claims exceed the amounts set aside in the disputed claims reserve, we will be permitted under the indenture governing the notes to issue additional securities in an amount up to $100 million containing terms similar to the Plan Notes.

Project Indebtedness

The following are descriptions of certain indebtedness of NRG's project subsidiaries that will likely remain outstanding after giving effect to the Reorganization Events and the Refinancing Transactions.

McClain

On November 28, 2001, NRG McClain LLC, or "McClain," entered into a credit agreement with Westdeutsche Landesbank Girozentrale, New York Branch, and other lending institutions for a $181 million secured term loan and an $8 million working capital facility. As of September 30, 2003, the outstanding principal amount under this facility was $157 million. The facility provides for a floating interest rate. As of September 30, 2003, the interest rate on such outstanding borrowings was 4.5%. There are currently a number of defaults under this credit agreement. On August 19, 2003, NRG signed an asset purchase agreement with Oklahoma Gas and Electric Company for substantially all of the assets of McClain and contemporaneously filed for bankruptcy pursuant to the asset purchase agreement. Upon consummation of the asset sale we anticipate that all proceeds from the sale will be used to repay outstanding project debt under the secured term loan and working capital facility.

Batesville

In May 1999, LSP Batesville Funding Corporation, or "Batesville," issued $150 million of 7.164% bonds (Series A) due January 2014 and $176 million of 8.16% bonds (Series B) due July 2025. In March 2000, Batesville exchanged these for Series C and Series D bonds, which are publicly traded, but in all other material respects are similar to Series A and B. The notes are secured by substantially all of the assets of and membership interests in NRG Batesville LLC, the project company subsidiary. As of September 30, 2003, $131 million and $176 million of principal remained outstanding under the Series C and D bonds, respectively.

Kendall

In 2001, LSP-Kendall Energy, LLC, or "Kendall," borrowed $505 million in floating rate bank debt due November 2006. The loan is secured by substantially all of the assets of and membership interests in Kendall. As of September 30, 2003, $489 million in principal remained outstanding. Kendall has hedged $222 million of the debt with fixed rates under four swap arrangements, at an all-in cost of 6.96% per annum. Due to a number of defaults under the credit agreement pursuant to which the Kendall debt was issued, including with respect to the non-payment of property taxes, we are in discussions with the lenders regarding restructuring such indebtedness.

Peakers

In June 2002, NRG Peaker Financing LLC, or "Peakers," 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 substantially all of the assets of and/or 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 September 30, 2003, $319 million in aggregate principal remained outstanding on these bonds. The bonds have been accelerated by XLCA due to cross-defaults on NRG debt and liens placed upon certain assets. In October 2003, Peakers obtained court approval for a restructuring agreement with XLCA. The restructuring agreement provides for, among other things, the provision of a letter of credit by NRG Energy, Inc. for the benefit of the secured parties in the Peaker financing, the cure or waiver of all defaults under the original financing agreement and the mutual release of claims by the parties.

NRG FinCo

We created a special purpose entity, NRG Finance Company I LLC, or "NRG FinCo," in March 2001 to secure financing for certain construction projects. NRG FinCo, together with various NRG subsidiary guarantors, have a $2.0 billion credit facility, known as the "NRG FinCo Secured Revolver," with Credit Suisse First Boston, as Administrative Agent, and certain other lending institutions party thereto. The NRG FinCo Secured Revolver was initially scheduled to mature on May 8, 2006; however, due to defaults thereunder by NRG FinCo and applicable guarantors, the lenders have accelerated all outstanding obligations. As of May 14, 2003, the aggregate outstanding amount under the NRG FinCo Secured Revolver was approximately $1.1 billion, and there was an aggregate of approximately $58 million of accrued and unpaid interest and commitment fees. $842 million of the outstanding amount is an allowed unsecured claim. The remaining balance will be satisfied when the NRG FinCo lenders exercise their security interests in our Nelson, Audrain and Pike projects.

NRG Thermal

NRG Thermal LLC, or "NRG Thermal," has several subsidiaries with outstanding long-term debt:

- NRG Energy Center Minneapolis LLC — $84 million of 7.31% senior secured notes due June 2013, of which $55.9 million remained outstanding as of September 30, 2003;
- NRG Energy Center Minneapolis LLC — $55 million of 7.25% senior secured notes due August 2017, of which $52.9 million remained outstanding as of September 30, 2003;
- NRG Energy Center Minneapolis LLC — $20 million of 7.12% senior secured notes due August 2017, of which $19.2 million remained outstanding as of September 30, 2003;
- NRG Energy Center San Francisco LLC — $6.8 million of 10.61% senior secured term notes due November 2004, of which $1.2 million remained outstanding as of September 30, 2003; and
- NRG Energy Center Pittsburgh LLC — $6.2 million of 10.61% senior secured term notes due November 2004, of which $1.9 million remained outstanding as of September 30, 2003.

Such indebtedness is secured principally by the subsidiaries' long-term assets and "cross-collateralized" by NRG Thermal's ownership interests in all of its subsidiaries and is guaranteed by NRG Thermal.

The three Minneapolis note agreements set forth above contain a covenant providing the lender the option to choose prepayment of the notes if, among other things, Xcel Energy no longer directly or indirectly owns a controlling interest in NRG Thermal. Xcel Energy will no longer own a controlling interest in NRG Thermal when we emerge from bankruptcy. In anticipation of the change in control, NRG Thermal has entered into a forbearance agreement with the lender to allow time to negotiate a modified loan covenant package that would enable the lender to choose not to exercise its change in control option. The forbearance agreement expires March 1, 2004.

PERC

In June 1998, Penobscot Energy Recovery Company, Limited Partnership, or "PERC," which is 50% indirectly owned by NRG, was financed through a $45.0 million fixed rate tax-exempt bond issuance by the Finance Authority of Maine. PERC issued $29.9 million in aggregate principal amount of 4.5% Series A bonds due July 2018; $3.1 million in aggregate principal amount of 5% Series B bonds due July 2018; and $12 million in aggregate principal amount of 5.2% Series B special term notes due July 2018. As of September 30, 2003, the outstanding balances for Series A, Series B and Series B special term bonds were $20.5 million, $3.1 million and $2.7 million, respectively.

CALP

In October 1991, the Commonwealth Atlantic Limited Partnership, or "CALP," which is 50% indirectly owned by NRG, entered into a credit arrangement with Credit Lyonnais, as administrative agent, for a floating rate term loan and working capital facility in an aggregate amount of approximately $105 million. On April 14, 1992, the agreement was amended to include an additional commitment of $18 million. The facility matures in October of 2012, however, the agreement provides for a mandatory prepayment on October 1, 2005 should the lenders not want to continue the facility. CALP is also party to an interest rate swap arrangement, covering most of the floating rate exposure. These arrangements are secured by substantially all the assets of CALP. As of September 30, 2003, there was approximately $67.2 million in principal outstanding under the facility.

Cadillac Renewable Energy

In April 1997, Cadillac Renewable Energy LLC, or "CRE," which is 50% indirectly owned by NRG, issued $1 million in aggregate principal amount of 8% notes and an additional $820,000 in aggregate principal amount of 8% notes. Each series of notes matures in 2007. As of September 30, 2003, the outstanding principal balances on these notes were $760,000 and $630,000, respectively. In July 1997 CRE entered into a $500,000 working capital line, which was fully drawn as of September 30, 2003. In addition, CRE entered into an operating lease arrangement with General Electric Credit and Lease Corporation, or "GE." The GE lease payments total $58.6 million in the aggregate over the term of the lease. The lease is not consolidated, as per GAAP, and is not included in amounts of outstanding indebtedness.

Saguaro

In July 1992, Saguaro Power Company, or "Saguaro," which is indirectly 50% owned by NRG, entered into a $100 million floating-rate, asset-secured credit agreement with Credit Lyonnais, as administrative agent. The agreement also includes a $3 million working capital facility. Subsequent to the financing, Saguaro entered into an interest rate swap agreement, as a result of which it pays 6.71% fixed interest per annum on the term facility. The interest rate swap matures May 2, 2005 and the term facility matures April 30, 2005. As of September 30, 2003, there was $24.2 million of principal outstanding under the credit facility and $3 million drawn on the working capital facility.

STS Hydropower

STS Hydropower, LTD, or "STS Hydropower," which is indirectly 50% owned by NEO, a wholly-owned subsidiary of NRG, 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 September 30, 2003, all required covenants under the restructured facility had been met and $24.7 million of principal was outstanding.

Northbrook Carolina Hydro

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," which is indirectly 70% owned by NEO, was amended to cross-collateralize the NCH and NNY notes. 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 September 30, 2003, the outstanding principal balance was $2.4 million. On December 2001, NCH purchased a $300,000 subordinated note from NEO. This subordinated note accrues interest at 11% per annum, and no payment is due until maturity on December 31, 2018.

In September 1999, NNY entered into a $17.5 million term loan agreement with Heller Financial. In December 2001, the credit agreement with Heller Financial was amended to include $2.6 million of financing for 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 the substantially all of the assets and membership interests in the NNY and NCH facilities. The outstanding principal amount outstanding as of September 30, 2003 was $17.1 million.

Camas

In November 1990, the Industrial Revenue Bond Public Corporation of Clark County, Washington issued $15.0 million in aggregate principal amount of 7.2% fixed interest Series A tax-exempt bonds due August 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 matures in August 2007 and, pursuant to the indenture, can no longer be re-marketed. As of September 30, 2003, $5.8 million of principal remained outstanding. In 1997, Camas also acquired a $19.6 million floating-rate bank loan from Fort James Corporation, maturing July 2007. The principal outstanding on this facility was $9.2 million as of September 30, 2003.

Calpine — Cogen America

The Calpine — Cogen America company, in which NRG owns a 20% interest, is a portfolio of project companies. As of September 30, 2003, Calpine Morris carried $127.9 million in notes payable; Calpine Prior carried $51.7 million in notes payable; Calpine Newark carried $48.4 million in project financing; Calpine Parlin carried 87.2 million in notes payable and project financing; Gray's Ferry carried $14.0 million in notes payable, and Cogen Corporate carried $64.8 million.

International Projects

Cobee

Compania Boliviana de Energia Electrica S.A., Bolivian Power Company Limited, or "Cobee," is the second largest electrical generation company in Bolivia. Cobee secured $75 million in loans from Corporacion Andina de Fomento in 1997 to finance an expansion project. As of September 30, 2003, Cobee's debt consisted of US$31.8 million: US$17.0 million "A loans" at LIBOR plus 4.5% per annum with maturity in July 31, 2007 and $14.9 million "B loans" at LIBOR plus 4.0% per annum, with a maturity of July 31, 2005. There is currently a default under this agreement as a result of the NRG bankruptcy filing.

Itiquira

In July 2001, Itiquira Energetica S.A., or "Itiquira," a hydro electric project company located in Brazil, signed a bridge debt financing agreement with União de Bancos Brasileiro S.A., or "Unibanco," for R$40 million (subsequently increased to a total of R$55 million). The maturity of the bridge debt financing was recently extended to June 2004. As of September 30, 2003, the outstanding principal balance on the bridge debt financing was the equivalent of US$19 million. Itiquira is currently in the process of structuring long term financing with Unibanco that will ultimately replace the bridge debt financing.

Enfield

In conjunction with equity provided by the project's owners, non-recourse financing was put in place in December 1997 to partially fund the construction of Enfield, which is 25% indirectly owned by NRG. The debt facilities were originally underwritten by ABN Amro Bank NV, and were subsequently syndicated. As of September 30, 2003, the financing consisted of a term loan, with GBP 89.0 million (US$148 million) outstanding; a working capital facility, with GBP 5 million (US$8 million) outstanding; and three letter of credit facilities, under which GBP 40 million (US$67 million) has been drawn. With the exception of one letter of credit facility, which matures on March 31, 2006, all facilities mature on December 31, 2017. Further, a swap arrangement with a notional amount of GBP 143.8 million was entered into to hedge the interest rate risk of the term facility. The arrangement swaps a LIBOR-based floating rate for the fixed rate of 6.93% over the life of the term facility. There is currently a default under this facility as a result of the failure to post required collateral and NRG's bankruptcy filing.

MIBRAG

MIBRAG mbH (a German limited liability company), which is 50% indirectly owned by NRG, has entered into a number of facilities in connection with the development of its business. As of September 30, 2003, there were a total of thirteen individual loans with €175 million (US$203 million) plus a tax lease with €45 million (US$52 million) outstanding. All facilities are on fixed rates at an average of 5.49% and all but two have maturities in various years between 2008 and 2017. The other two loans (value €1.27 million (US$1.47 million)) are in respect of pension liabilities, and are stated repayable upon termination of MIBRAG.

The loans raised in connection with the three power plants contain security interests over the plants and the loans raised in connection with the development of the Schleenhain mine are unsecured. The tax lessor owns the land on which the Mumsdorf power plant is sited, although MIBRAG has the right to reacquire this land when the tax lease is repaid in 2008. MIBRAG is currently evaluating the possibility of refinancing some or all of its debt.

Schkopau

The Kraftwerke Schkopau GbR, or "Schkopau," which is approximately 42% indirectly owned by NRG, partnership issued debt pursuant to multiple facilities totaling approximately €784.5 million to finance the construction of the Schkopau power plant. As of September 30, 2003, €493.3 million of principal remained outstanding. Interest on each of these facilities accrues at fixed rates at an average of 6.68% per annum. Each of these facilities matures between 2005 to 2015. Schkopau is a partnership between Saale Energie GmbH, an NRG subsidiary and German limited liability company, and E.ON Kraftwerke AG, a German joint GmbH, another German limited liability company. As a result, lenders to the project rely almost exclusively on the creditworthiness of E.ON Kraftwerke AG GmbH. Saale Energie remains liable to the lenders as a partner in the borrower, but there is no recourse to NRG. Six of the original loans were refinanced in September 2003, extending their terms from an average of seven years to 12 years and reducing the interest margin.

Loy Yang

The Loy Yang Power financing includes senior and junior debt issued at AUD 3.55 billion with maturities extending through 2027. Eighty percent of the senior debt floating rate interest exposure was swapped to fixed rate at financial close in May 1997 as per the financing agreements. Loy Yang manages the remaining floating exposure in accordance with its hedging policy. The total outstanding principal as of September 30, 2003 was AUD 3.2 billion (approximately $2.2 billion). Negotiations are currently taking place relating to restructuring this indebtedness. We currently own approximately 25% of Loy Yang Power Partnership.

Flinders

NRG Flinders, a wholly owned subsidiary of NRG, has AUD 315 million available in senior bank debt financing from two bank facilities. The first is a AUD 150 floating-rate syndicated facility that matures in September 2012. The second facility, which is intended to fund the refurbishment of the Playford station, allows Flinders to draw up to AUD 137 million (approximately $93 million) at a floating-rate on drawn amounts and matures coterminous with the first facility. As of September 30, 2003, the project had drawn AUD 89 million (approximately $59 million) on the refurbishment facility, with the rest of the facility to be drawn down as the Playford refurbishment is completed. The total outstanding balance for the two facilities as of September 30, 2003, is AUD 226 million (approximately $153 million). The Flinders group has agreed with the lenders to hedge not less than 60% of its floating interest exposure until June 30, 2005 and not less than 40% of its floating interest exposure through the end of the loan.

Gladstone

Upon NRG's acquisition of the Gladstone Power Station from the Queensland government in 1994, the project issued AUD 635 million in a syndicated amortizing loan in March 1994 with a final repayment date of March 2009. The total outstanding principal as of September 30, 2003 was AUD 360 million (approximately $135 million). The loan will be fully amortized by April 30, 2009. We own approximately 38% of Gladstone Power Station through an unincorporated joint venture.

Hsin Yu

Hsin Yu, which is approximately 63% indirectly owned by NRG, entered into a NT$2,700 million syndicated loan arrangement to finance construction of what was to be the first phase of a multi-phase cogeneration facility. The original financing was led by Chiao Tung Bank and carries an average interest rate of 6.47%. Principal covenants of the syndicated facility include maintaining a debt to equity ratio below 250% until 2006, and a ratio below 200% thereafter, and maintaining a debt service coverage ratio above 1.1, starting in 2004. As of September 30, 2003, there was NT$2,511 million (approximately US$74.4 million) of principal outstanding under this facility. In addition to this facility, as of September 30, 2003, the Hsin Yu project carried a capital lease valued at NT$132 million (approximately US$3.9 million) and external notes payable of NT$409 million (approximately US$12.1 million). There are currently defaults under such credit arrangements.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS

To the Board of Directors and Stockholder

of NRG Energy, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, cash flows and stockholder's (deficit)/ equity present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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 our audits provide a reasonable basis for our opinion.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 and Note 29 to the consolidated financial statements, the Company is experiencing credit and liquidity constraints and has various credit arrangements that are in default. As a direct consequence, during 2002 the Company entered into discussions with its creditors to develop a comprehensive restructuring plan. In connection with its restructuring efforts, the Company and certain of its subsidiaries filed for Chapter 11 bankruptcy protection. These conditions raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in Note 19 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets", for the year ended December 31, 2002. As discussed in Note 26 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," on January 1, 2001. As discussed in Notes 3 and 5 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," on January 1, 2002.

/s/ PRICEWATERHOUSECOOPERS LLP
PricewaterhouseCoopers LLP

Minneapolis, Minnesota

March 28, 2003, except as to Notes 29 and 30, which are as of December 3, 2003

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2002	2001	2000
		(In thousands)	
Operating Revenues and Equity Earnings			
Revenues from majority-owned operations	$ 2,088,432	$ 2,191,152	$1,669,531
Equity in earnings of unconsolidated affiliates	68,996	210,032	139,364
Total operating revenues and equity earnings	2,157,428	2,401,184	1,808,895
Operating Costs and Expenses			
Cost of majority-owned operations	1,398,965	1,412,006	1,053,225
Depreciation and amortization	241,521	163,014	94,078
General, administrative and development	226,528	193,249	168,945
Write downs and losses on sales of equity method investments	200,472	—	—
Special charges	2,627,766	—	—
Total operating costs and expenses	4,695,252	1,768,269	1,316,248
Operating (Loss)/ Income	(2,537,824)	632,915	492,647
Other Income (Expense)			
Minority interest in (earnings)/ losses of consolidated subsidiaries	(1,290)	(1,847)	(840)
Other income, net	4,232	19,720	5,796
Interest expense	(484,570)	(387,688)	(249,677)
Total other expense	(481,628)	(369,815)	(244,721)
(Loss)/ Income From Continuing Operations Before Income Taxes	(3,019,452)	263,100	247,926
Income Tax (Benefit)/ Expense	(163,236)	39,298	98,360
(Loss)/ Income From Continuing Operations	(2,856,216)	223,802	149,566
(Loss)/ Income on Discontinued Operations, net of Income Taxes	(608,066)	41,402	33,369
Net (Loss)/ Income	$(3,464,282)	$ 265,204	$ 182,935

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2002	2001	2000
		(In thousands)	
Cash Flows from Operating Activities			
Net (loss)/ income	$(3,464,282)	$ 265,204	$ 182,935
Adjustments to reconcile net (loss)/ income to net cash provided by operating activities			
Undistributed equity in earnings of unconsolidated affiliates	(22,252)	(119,002)	(43,258)
Depreciation and amortization	286,623	212,493	122,953
Amortization of deferred financing costs	28,367	10,668	7,678
Special charges	3,144,509	—	—
Write downs and losses on sales of equity method investments	196,192	—	—
Deferred income taxes and investment tax credits	(230,134)	45,556	38,458
Unrealized (gains)/ losses on energy contracts	(2,743)	(13,257)	—
Minority interest	(19,325)	6,564	4,993
Amortization of out of market power contracts	(89,415)	(54,963)	—
Gain on sale of discontinued operations	(2,814)	—	—
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions			
Accounts receivable, net	(15,487)	89,523	(198,091)
Accounts receivable — affiliates	2,271	—	10,703
Inventory	42,596	(111,131)	(12,316)
Prepayments and other current assets	(58,367)	(36,530)	(608)
Accounts payable	278,900	(4,512)	143,045
Accounts payable — affiliates	47,049	4,989	—
Accrued income taxes	44,137	(75,132)	39,137
Accrued property and sales taxes	27,481	4,054	3,743
Accrued salaries, benefits, and related costs	(24,912)	15,785	(8,153)
Accrued interest	203,234	35,637	38,479
Other current liabilities	47,692	82,754	(5,136)
Other assets and liabilities	10,723	(82,686)	37,116
Net Cash Provided by Operating Activities	430,043	276,014	361,678
Cash Flows from Investing Activities			
Acquisitions, net of liabilities assumed	—	(2,813,117)	(1,912,957)
Proceeds from sale of discontinued operations	160,791	—	—
Proceeds from sale of investments	68,517	4,063	8,917
Decrease/ (increase) in restricted cash	(197,802)	(99,707)	5,306
Decrease/ (increase) in notes receivable	(209,244)	45,091	(5,444)
Capital expenditures	(1,439,733)	(1,322,130)	(223,560)
Proceeds from sale of property	—	—	9,785
Investments in projects	(63,996)	(149,841)	(86,195)
Net Cash Used in Investing Activities	(1,681,467)	(4,335,641)	(2,204,148)
Cash Flows from Financing Activities			
Net borrowings/ (payments) under line of credit agreement	790,000	202,000	(367,766)
Proceeds from issuance of stock	4,065	475,464	453,719
Proceeds from issuance of corporate units (warrants)	—	4,080	—
Proceeds from issuance of short term debt	—	622,156	—
Capital contributions from parent	500,000	—	—
Proceeds from issuance of long-term debt	1,086,770	3,268,017	3,034,909
Principal payments on long-term debt	(931,505)	(418,171)	(1,214,992)
Net Cash Provided by Financing Activities	1,449,330	4,153,546	1,905,870
Effect of Exchange Rate Changes on Cash and			

Cash Equivalents	24,950	(3,055)	360
Change in Cash from Discontinued Operations	53,253	(22,276)	(57,640)
Net Increase in Cash and Cash Equivalents	276,109	68,588	6,120
Cash and Cash Equivalents at Beginning of Year	105,405	36,817	30,697
Cash and Cash Equivalents at End of Year	$ 381,514	$ 105,405	$ 36,817

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2002	December 31, 2001
	(In thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 381,514	$ 105,405
Restricted cash	277,489	140,323
Accounts receivable — trade, less allowance for doubtful accounts of $18,163 and $13,300	273,944	219,879
Income tax receivable	4,320	42,027
Accounts receivable — affiliate	—	4,937
Inventory	265,585	307,374
Current portion of notes receivable	5,442	737
Derivative instruments valuation	28,791	15,938
Prepayments and other current assets	138,567	42,257
Current assets — discontinued operations	119,509	330,195
Total current assets	1,495,161	1,209,072
Property, Plant and Equipment		
In service	6,499,685	5,211,513
Under construction	623,750	2,923,037
Total property, plant and equipment	7,123,435	8,134,550
Less accumulated depreciation	(602,712)	(401,877)
Net property, plant and equipment	6,520,723	7,732,673
Other Assets		
Equity investments in affiliates	884,263	1,038,195
Notes receivable, less current portion	985,253	772,089
Decommissioning fund investments	4,617	4,336
Intangible assets, net of accumulated amortization of $22,110 and $20,053	76,639	79,972
Debt issuance costs, net of accumulated amortization of $49,670 and $25,357	136,346	95,680
Derivative instruments valuation	90,766	96,017
Other assets, net of accumulated amortization of $4,250 and $2,819	20,193	22,787
Non-current assets — discontinued operations	678,822	1,865,439
Total other assets	2,876,899	3,974,515
Total Assets	$10,892,783	$12,916,260

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS — (Continued)

	December 31,	
	2002	2001
	(In thousands)	
LIABILITIES AND STOCKHOLDER'S (DEFICIT)/EQUITY		
Current Liabilities		
Current portion of long-term debt	$ 7,026,771	$ 44,611
Revolving line of credit	1,000,000	170,000
Revolving line of credit, non-recourse debt	—	40,000
Project-level, non-recourse debt	30,064	22,156
Corporate level, recourse debt	—	600,000
Accounts payable — trade	556,712	230,227
Accounts payable — affiliate	50,659	—
Accrued property, sales and other taxes	24,420	14,499
Accrued salaries, benefits and related costs	21,018	38,554
Accrued interest	289,553	94,383
Derivative instruments valuation	13,439	21,910
Other current liabilities	110,645	93,456
Current liabilities — discontinued operations	694,464	602,523
Total current liabilities	9,817,745	1,972,319
Other Liabilities		
Long-term debt	1,184,287	4,301,860
Corporate level long-term, recourse debt	—	2,972,400
Deferred income taxes	91,634	291,040
Postretirement and other benefit obligations	67,495	75,000
Derivative instruments valuation	91,039	36,389
Other long-term obligations and deferred income	154,710	211,177
Minority interest	29,625	23,698
Non-current liabilities — discontinued operations	152,447	795,248
Total liabilities	11,588,982	10,679,131
Commitments and Contingencies		
Stockholder's (Deficit)/ Equity		
Class A — Common stock; $.01 par value; 100 shares and 250,000,000 shares authorized in 2002 and 2001; 3 shares and 147,604,500 shares issued and outstanding at December 31, 2002 and 2001	—	1,476
Common stock; $.01 par value; 100 shares and 550,000,000 shares authorized in 2002 and 2001; 1 share and 50,939,875 shares issued and outstanding at December 31, 2002 and 2001	—	509
Additional paid-in capital	2,227,692	1,713,984
Retained (deficit) earnings	(2,828,933)	635,349
Accumulated other comprehensive loss	(94,958)	(114,189)
Total Stockholder's (Deficit)/Equity	(696,199)	2,237,129
Total Liabilities and Stockholder's (Deficit)/Equity	$10,892,783	$12,916,260

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDER'S (DEFICIT)/EQUITY

	Class A Common		Common		Additional Paid-in Capital	Retained Earnings/ (Deficit)	Accumulated Other Comprehensive (Loss)/Income	Total Stockholder's (Deficit)/ Equity
	Stock	Shares	Stock	Shares				
					(In thousands)			
Balances at December 31, 1999	$ 1,476	147,605	$ —	—	$ 780,438	$ 187,210	$ (75,470)	$ 893,654
Net income						182,935		182,935
Foreign currency translation adjustments							(68,220)	(68,220)
Comprehensive income for 2000								114,715
Issuance of common stock, net of issuance costs of $32.2 million			324	32,396	453,395			453,719
Balances at December 31, 2000	$ 1,476	147,605	$324	32,396	$1,233,833	$ 370,145	$ (143,690)	$ 1,462,088
Net income						265,204		265,204
Foreign currency translation adjustments and other							(41,600)	(41,600)
Deferred unrealized gains, net on derivatives							71,101	71,101
Comprehensive income for 2001								294,705
Capital stock activity:								
Issuance of corporate units/ warrant					4,080			4,080
Tax benefits of stock option exercise					792			792
Issuance of common stock, net of issuance costs of $23.5 million			185	18,543	475,279			475,464
Balances at December 31, 2001	$ 1,476	147,605	$ 509	50,939	$ 1,713,984	$ 635,349	$ (114,189)	$ 2,237,129
Net loss						(3,464,282)		(3,464,282)
Foreign currency translation adjustments and other							64,054	64,054
Deferred unrealized loss, net on derivatives							(44,823)	(44,823)
Comprehensive loss for 2002								(3,445,051)

Contribution from parent					502,874			502,874
Issuance of common stock			6	591	8,843			8,849
Impact of exchange offer	(1,476)	(147,605)	(515)	(51,530)	1,991			—
Balances at December 31, 2002	$ —	—	$ —	—	$2,227,692	$(2,828,933)	$ (94,958)	$ (696,199)

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization

NRG Energy, Inc., (NRG Energy or the Company), was incorporated as a Delaware corporation on May 29, 1992. Beginning in 1989, NRG Energy conducted business through its predecessor companies, NRG Energy, Inc. and NRG Group, Inc., Minnesota corporations, which were merged into NRG Energy subsequent to its incorporation. NRG Energy, together with its majority owned subsidiaries and affiliates, is an energy company primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products.

On June 5, 2000, NRG Energy completed its initial public offering. Prior to its initial public offering, NRG Energy was a wholly owned subsidiary of Northern States Power (NSP). In August 2000, NSP merged with New Century Energies, Inc. (NCE), a Colorado-based public utility holding company. The surviving corporation in the merger was renamed Xcel Energy Inc. (Xcel Energy or Parent), Xcel Energy directly owns six utility subsidiaries that serve electric and natural gas customers in 12 states. Xcel Energy also owns or has interests in a number of non-regulated businesses, the largest of which is NRG Energy. In March 2001, NRG Energy completed a second public offering of 18.4 million shares of its common stock. Following this offering, Xcel Energy indirectly owned a 74% interest in NRG Energy's common stock and class A common stock, representing 96.7% of the total voting power of NRG Energy's common stock and class A common stock.

Since the early 1990's, NRG Energy pursued a strategy of growth through acquisitions. Starting in 2000, NRG Energy added the development of new construction projects to this strategy. This strategy required significant capital, much of which was satisfied primarily with third party debt. As of December 31, 2002, NRG Energy had approximately $9.4 billion of debt on its balance sheet at the corporate and project levels. Due to a number of reasons, including the overall down-turn in the energy industry, NRG Energy's financial condition has deteriorated significantly. As a direct consequence, in 2002 NRG Energy entered into discussions with its creditors in anticipation of a comprehensive restructuring in order to become a more stable and conservatively capitalized company. In connection with its restructuring efforts, it is likely that NRG Energy (and certain of its subsidiaries) will file for Chapter 11 bankruptcy protection. If NRG Energy were to file for Chapter 11 bankruptcy protection, Xcel Energy's equity ownership would most likely be eliminated and a large number of NRG Energy's creditors' claims would be impaired.

On March 26, 2003, Xcel Energy announced that its board of directors had approved a tentative settlement agreement with holders of most of NRG Energy's long-term notes and the steering committee representing NRG's bank lenders. The settlement is subject to certain conditions, including the approval of at least a majority in dollar amount of the NRG Energy bank lenders and long-term noteholders and definitive documentation. There can be no assurance that such approvals will be obtained. The terms of the settlement call for Xcel Energy to make payments to NRG Energy over the next 13 months totaling up to $752 million for the benefit of NRG Energy's creditors in consideration for their waiver of any existing and potential claims against Xcel Energy. Under the settlement, Xcel Energy will make the following payments: (i) $350 million at or shortly following the consummation of a restructuring of NRG Energy's debt. It is expected this payment would be made prior to year-end 2003; (ii) $50 million on January 1, 2004. At Xcel Energy's option, it may fill this requirement with either cash or Xcel Energy common stock or any combination thereof; and (iii) $352 million in April 2004.

NRG Energy is restructuring its operations to become a domestic based owner-operator of a fuel-diverse portfolio of electric generation facilities engaged in the sale of energy, capacity and related products. NRG Energy is working toward this goal by selective divestiture of non-core assets, consolidation of management, reorganization and redirection of power marketing philosophy and activities and an overall financial restructuring that will improve liquidity and reduce debt. NRG Energy does not anticipate any new significant acquisitions or construction, and instead will focus on operational performance and asset management. NRG Energy has already made significant reductions in expenditures, business development activities and personnel. Power sales, fuel procurement and risk management will remain a key strategic element of NRG Energy's operations. NRG Energy's objective will be to optimize the fuel input and the energy output of its facilities within an appropriate risk and liquidity profile.

In December 2001, Moody's Investor Service (Moody's) placed NRG Energy's long-term senior unsecured debt rating on review for possible downgrade. In response, Xcel Energy and NRG Energy put into effect a plan to preserve NRG Energy's investment grade rating and improve its financial condition. This plan included financial support to NRG Energy from Xcel Energy; marketing certain NRG Energy assets for sale; canceling and deferring capital spending; and reducing corporate expenses.

In response to a possible downgrade, during 2002, Xcel Energy contributed $500 million to NRG Energy, and NRG Energy and its subsidiaries sold assets and businesses that provided NRG Energy in excess of $286 million in cash and eliminated approximately $432 million in debt. NRG Energy also cancelled or deferred construction of approximately 3,900 MW of new generation projects. On July 26, 2002, Standard & Poors' (S&P) downgraded NRG Energy's senior unsecured bonds to below investment grade, and three days later Moody's also downgraded NRG Energy's senior unsecured debt rating to below investment grade. Since July 2002, NRG Energy senior unsecured debt, as well as the secured NRG Northeast Generating LLC bonds, the secured NRG South Central Generating LLC bonds and secured LSP Energy (Batesville) bonds were downgraded multiple times. After NRG Energy failed to make payments due under certain unsecured bond obligations on September 16, 2002, both Moody's and S&P lowered their ratings on NRG Energy's and its subsidiaries' unsecured bonds once again. Currently, NRG Energy's unsecured bonds carry a rating of between CCC and D at S&P and between Ca and C at Moody's, depending on the specific debt issue.

As a result of the downgrade of NRG Energy's credit rating, declining power prices, increasing fuel prices, the overall down-turn in the energy industry and the overall down-turn in the economy, NRG Energy has experienced severe financial difficulties. These difficulties have caused NRG Energy to, among other things, miss scheduled principal and interest payments due to its corporate lenders and bondholders, prepay for fuel and other related delivery and transportation services and provide performance collateral in certain instances. NRG Energy has also recorded asset impairment charges of approximately $3.1 billion, related to various operating projects, as well as projects that were under construction which NRG Energy has stopped funding.

NRG Energy and its subsidiaries have failed to timely make interest and/or principal payments on substantial amounts of its indebtedness:

In addition, the following issues have been accelerated, rendering the debt immediately due and payable: on November 6, 2002, lenders to NRG Energy accelerated the approximately $1.1 billion of debt under the construction revolver facility; on November 21, 2002, the bond trustee, on behalf of bondholders, accelerated the approximately $750 million of debt under the NRG South Central Generating, LLC facility; and on February 27, 2003, ABN Amro, as administrative agent, accelerated the approximately $1.0 billion corporate revolver financing facility.

In addition to payment defaults, prior to the downgrades, many corporate guarantees and commitments of NRG Energy and its subsidiaries required that they be supported or replaced with letters of credit or cash collateral within 5 to 30 days of a ratings downgrade below Baa3 or BBB- by Moody's or Standard & Poor's, respectively. As a result of the downgrades on July 26 and July 29, NRG Energy received demands to post collateral aggregating approximately $1.1 billion.

On August 19, 2002, NRG Energy executed a Collateral Call Extension Letter (CCEL) with various secured project lender groups in which the banks agreed to extend until September 13, 2002, the deadline by which NRG Energy was to post its approximately $1.0 billion of cash collateral in connection with certain bank loan agreements.

Effective as of September 13, 2002, NRG Energy and these various secured project lenders entered into a Second Collateral Call Extension Letter (Second CCEL) that extended the deadline until November 15, 2002. Under the Second CCEL, NRG Energy agreed to submit to the lenders a comprehensive restructuring plan. NRG Energy submitted this plan on November 4, 2002 and continues to work with its lenders and advisors on an overall restructuring of its debt (see further discussion below). The November 15, 2002 deadline of the second CCEL passed without NRG Energy posting the required collateral. NRG Energy and the secured project lenders continue to work towards a plan of restructuring.

In August 2002, NRG Energy retained financial and legal restructuring advisors to assist its management in the preparation of a comprehensive financial and operational restructuring. NRG Energy and its advisors have been meeting regularly to discuss restructuring issues with an ad hoc committee of its bondholders and a steering committee of its bank lenders (the Ad Hoc Creditors Committees).

To aid in the design and implementation of a restructuring plan, in the fall of 2002, NRG Energy prepared a comprehensive business plan and forecast. Anticipating that NRG Energy's creditors will own all or substantially all of NRG Energy's equity interests after implementing the restructuring plan, any plans and efforts to integrate NRG Energy's business operations with those of Xcel Energy were terminated. Using commodity, emission and capacity prices provided by an independent energy consulting firm to develop forecasted cash flow information, management concluded that the forecasted free cash flow available to NRG Energy after servicing project level obligations will be insufficient to service recourse debt obligations at the NRG Energy corporate level. Based on that forecast, it is anticipated that NRG Energy will remain in default of the various corporate level debt obligations discussed more fully herein.

Based on this information and in consultation with Xcel Energy and its financial and legal restructuring advisors, NRG Energy prepared a comprehensive financial restructuring plan. In November 2002, NRG Energy and Xcel Energy presented the plan to the Ad Hoc Creditors Committees. The restructuring plan has served as a basis for continuing negotiations between the Ad Hoc Creditors Committees, NRG Energy and Xcel Energy related to a consensual plan of reorganization for NRG Energy. Negotiations have progressed substantially since the initial plan was presented in November. If an agreement to a consensual plan of reorganization is negotiated and NRG Energy is unable to effectuate the restructuring through an exchange offer or other non-bankruptcy mechanism, it is highly probable that such plan would be implemented through the commencement of a voluntary Chapter 11 bankruptcy proceeding. There can be no assurance that NRG Energy's creditors, including, but not limited to the Ad Hoc Committees, will agree to the terms of the consensual plan of reorganization currently being negotiated. In addition, there can be no guarantee that lenders will not seek to enforce their remedies under the various loan agreements, provided that any such attempted enforcement would be subject to the automatic stay and other relevant provisions of the bankruptcy code. The commencement of a voluntary Chapter 11 bankruptcy proceeding without a consensual plan of reorganization would increase the possibility of a prolonged bankruptcy proceeding.

On November 22, 2002, five former NRG Energy executives filed an involuntary Chapter 11 petition against NRG Energy in U.S. Bankruptcy Court for the District of Minnesota. Under provisions of federal law, NRG Energy has the full authority to continue to operate its business as if the involuntary petition had not been filed unless and until a court hearing on the validity of the involuntary petition is resolved adversely to NRG Energy. On December 16, 2002, NRG Energy responded to the involuntary petition, contesting the petitioners' claims and filing a motion to dismiss the case. On February 19, 2003, NRG Energy announced that it had reached a settlement with the petitioners. The U.S. Bankruptcy Court for the District of Minnesota will hear NRG Energy's motion to consider the settlement and/or dismiss the involuntary petition. Two of NRG Energy's creditors have objected to the motion to dismiss. There can be no assurance that the court will dismiss the involuntary petition. The Bankruptcy Court has discretion in the review of the settlement agreement. There is a risk that the Bankruptcy Court may, among other things, reject the settlement agreement or enter an order for relief under Chapter 11.

On March 26, 2003, Xcel Energy announced that its board of directors had approved a tentative settlement agreement with holders of most of NRG Energy's long-term notes and the steering committee representing NRG's bank lenders. The settlement is subject to certain conditions, including the approval of at least a majority in dollar amount of the NRG Energy bank lenders and long-term noteholders and definitive documentation. There can be no assurance that such approvals will be obtained. The terms of the settlement call for Xcel Energy to make payments to NRG Energy over the next 13 months totaling up to $752 million for the benefit of NRG Energy's creditors in consideration for their waiver of any existing and potential claims against Xcel Energy. Under the settlement, Xcel Energy will make the following payments: (i) $350 million at or shortly following the consummation of a restructuring of NRG Energy's debt. It is expected this payment would be made prior to year-end 2003; (ii) $50 million on January 1, 2004. At Xcel Energy's option, it may fill this requirement with either cash or Xcel Energy common stock or any combination thereof; and (iii) $352 million in April 2004.

NRG Energy expects to have cash available for operations through 2003. This forecast does not assume further investment by Xcel Energy or modification of NRG Energy's current debt obligations. In the event that NRG Energy is unable to work through the issues as described above and is unable to obtain adequate financing on terms acceptable to NRG Energy to continue its operations, NRG Energy may have to file bankruptcy. NRG Energy's inability to obtain timely waivers and avoid defaults on their credit obligations could lead to additional involuntary bankruptcy proceedings. In any case, there is substantial doubt as to NRG Energy's ability to continue as a going concern.

The accompanying financial statements have been prepared assuming NRG Energy will continue as a going concern. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

See Note 29 for additional disclosures covering NRG Energy's bankruptcy proceedings.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include NRG Energy's accounts and those of its subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation. Accounting policies for all of NRG Energy's operations are in accordance with accounting principles generally accepted in the United States of America. As discussed in Note 10, NRG Energy has investments in partnerships, joint ventures and projects. Investments in such businesses in which NRG Energy does not have control, but has the ability to exercise significant influence over the operating and financial policies, are accounted for under the equity method. Earnings from equity in international investments are recorded net of foreign income taxes. The more significant accounting policies are as follows:

Nature of Operations

The principal business of NRG Energy is the ownership and operation, through its subsidiaries, of power generation facilities and the sale of energy, capacity and related products in the United States and internationally. NRG Energy also has investments in alternative energy, thermal and resource recovery facilities.

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 cash collateral for letters of credit issued in relation to project development activities, funds held in trust accounts to satisfy the requirements of certain debt agreements and funds held within NRG Energy's 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 or the present value of minimum lease payments for assets under capital leases. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred. Depreciation is computed using the straight-line method over the following estimated useful lives:

Facilities and improvements	10-45 years
Machinery and equipment	7-30 years
Office furnishings and equipment	3-5 years

The assets and related accumulated depreciation amounts are adjusted for asset retirements and disposals with the resulting gain or loss included in operations. NRG Energy expenses all repair and maintenance as incurred, including planned major maintenance.

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 were performed in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," (SFAS No. 144) in 2002 and SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of" (SFAS No. 121) in prior years. An impairment loss is recognized if the total future estimated undiscounted cash flows expected from an asset is less than its carrying value. An impairment charge is measured by the difference between an asset's carrying amount and fair value. Fair values are determined by a variety of valuation methods, including appraisals, sales prices of similar assets and present value techniques.

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

Assets Held for Sale

Long-lived assets are classified as held for sale 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. Assets held for sale 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 $64.8 million, $27.2 million, and $2.7 million in 2002, 2001 and 2000, 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 the project has been approved by NRG Energy's Board of Directors. Additional costs incurred after this point are capitalized. When a project begins operation, previously capitalized project costs are reclassified to equity investments in affiliates or property, plant and equipment and amortized on a straight-line basis over the lesser of the life of the project's related assets or revenue contract period. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

Debt Issuance Costs

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

Goodwill and Intangible Assets

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

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

Income Taxes

Following the completion of Xcel Energy's exchange offer on June 3, 2002, NRG and subsidiaries can rejoin the Xcel Energy's group for federal income tax purposes provided the Internal Revenue Service (IRS) consents. Because it is likely that Xcel Energy will not request IRS consent to consolidate NRG Energy for income tax purposes in 2002, the income tax provision for NRG Energy is based on a consolidated NRG Energy group through June 3, 2002 and separate corporate tax returns starting June 4, 2002 as discussed in Note 15. On a stand-alone basis, NRG Energy does not have the ability to recognize all tax benefits that may ultimately accrue from losses occurring in 2002. Deferred tax benefits have been recorded only to the extent a valuation allowance was not considered necessary. A current tax benefit has been recorded to the extent the 2002 tax losses can be carried back. Current tax expense has been recorded for those entities generating positive taxable income on a stand-alone basis in 2002.

In March 2001, NRG Energy was deconsolidated from Xcel Energy for federal income tax purposes. Prior to March 13, 2001, NRG Energy was included in the consolidated tax returns of Xcel Energy. NRG Energy calculated its income tax provision on a separate return basis under a tax sharing agreement with Xcel Energy. Current Federal and certain state income taxes were payable to or receivable from Xcel Energy.

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

Revenue Recognition

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

Electrical energy revenue is recognized upon delivery to the customer. 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.

NRG Energy provides contract operations and maintenance services to some of its non-consolidated affiliates. Revenue is recognized as contract services are performed.

NRG Energy uses the equity method of accounting to recognize as revenue its pro rata share of the net income or loss of unconsolidated investments.

NRG Energy recognizes other income for interest income on loans to affiliates, as the interest is earned and realizable.

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of NRG Energy’s 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 stockholder’s 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. NRG Energy recognized foreign currency transaction losses of $10.4 million, gains of $1.8 million and losses of $0.6 million in 2002, 2001 and 2000, respectively.

Concentrations of Credit Risk

Financial instruments, which potentially subject NRG Energy 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 NRG Energy’s 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, NRG Energy believes the credit risk posed by industry concentration is offset by the diversification and creditworthiness of its 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 and similar instruments with equivalent credit quality.

Stock Based Compensation

In 1995, the Financial Accounting Standard Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 123, "Accounting for Stock Based Compensation." NRG Energy has elected to continue to account for stock-based compensation using the intrinsic value method prescribed in Accounting Principle Board Opinion No. 25, "Accounting for Stock Issued to Employees." Accordingly, NRG Energy records expense, in an amount equal to the excess of the quoted market price on the grant date over the option price. Such expense is recognized at the grant date for options fully vested. For options with a vesting period, the expense is recognized over the vesting period. As of June 3, 2002, all stock options were converted into Xcel Energy stock options.

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, NRG Energy uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, un-collectible accounts, and 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.

New Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, *"Accounting for Asset Retirement Obligations"* (SFAS No. 143). This statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. 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. The liability is initially capitalized as part of the cost of the related tangible long-lived asset and thus depreciated over the asset's useful life. Accretion of the liabilities due to the passage of time will be an operating expense. 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 written or oral contracts, including obligations arising under the doctrine of promissory estoppel. NRG Energy is required to adopt SFAS No. 143 on January 1, 2003. NRG Energy is in the process of evaluating the impact of adopting SFAS No. 143 on its financial condition.

In April 2002, the FASB issued SFAS No. 145, *“Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections,”* (SFAS No. 145) that supercedes previous guidance for the reporting of gains and losses from extinguishment of debt and accounting for leases, among other things. SFAS No. 145 requires that only gains and losses from the extinguishment of debt that meet the requirements for classification as “Extraordinary Items,” as prescribed in Accounting Principles Board Opinion No. 30, should be disclosed as such in the financial statements. Previous guidance required all gains and losses from the extinguishment of debt to be classified as “Extraordinary Items.” This portion of SFAS No. 145 is effective for fiscal years beginning after May 15, 2002, with restatement of prior periods required. NRG Energy has no extraordinary gains or losses resulting from extinguishment of debt during the three years ended December 31, 2002 that will require restatement upon adoption of this part of the statement.

In addition, SFAS No. 145 amends SFAS No. 13, *“Accounting for Leases,”* (SFAS No. 13) as it relates to accounting by a lessee for certain lease modifications. Under SFAS No. 13, if a capital lease is modified in such a way that the change gives rise to a new agreement classified as an operating lease, the assets and obligation are removed, a gain or loss is recognized and the new lease is accounted for as an operating lease. Under SFAS No. 145, capital leases that are modified so the resulting lease agreement is classified as an operating lease are to be accounted for under the sale-leaseback provisions of SFAS No. 98, *“Accounting for Leases.”* These provisions of SFAS No. 145 were effective for transactions occurring after May 15, 2002. Adoption of SFAS No. 145 is not expected to have a material impact on NRG Energy.

In June 2002, the FASB issued SFAS No. 146, *“Accounting for Costs Associated with Exit or Disposal Activities,”* (SFAS No. 146), SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force (EITF) Issue No. 94-3, *“Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).”* SFAS No. 146 applies to costs associated with an exit activity that does not involve an entity newly acquired in a business combination or with a disposal activity covered by SFAS No. 144, *“Accounting for the Impairment or Disposal of Long-Lived Assets.”* The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002.

In November 2002, the FASB issued FASB Interpretation No. 45, *Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor’s fiscal year-end. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee. See Note 14.

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable Interest Entities* (FIN No. 46). FIN No. 46 requires an enterprise’s consolidated financial statements to include subsidiaries in which the enterprise has a controlling interest. Historically, that requirement has been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise’s consolidated financial statements do not include the consolidation of variable interest entities with which it has similar relationships but no majority voting interest. Under FIN No. 46 the voting interest approach is not effective in identifying controlling financial interest. Assets of entities consolidated upon adoption of the new standard will be initially recorded at their carrying amounts at the date the requirements of the new rule first apply. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value the first date the new rule applies. Any difference between the net amount of any previously recognized interest in the newly consolidated entity should be recognized as the cumulative effect of an accounting change. FIN No. 46 becomes effective in the third quarter of 2003. Fin No. 46 is not expected to have a significant impact on NRG Energy.

Reclassifications

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

Note 3 — Special Charges

The credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity experienced by NRG Energy during the third quarter of 2002 were "triggering events" which, pursuant to SFAS No. 144, required the Company to review the recoverability of its long-lived assets. As a result of this review, NRG Energy recorded asset impairment charges during 2002 totaling $2.5 billion for various projects in operation, under construction and in development as shown in the table below.

To determine whether an asset was impaired, NRG Energy 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 flow included only future cash flows, net of associated cash outflows, directly associated with and expected to arise as a result of NRG Energy's 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, whereas assets under construction or in development were based on expected service potential when complete. The cash flow estimates included probability weightings to consider possible alternative courses of action and outcomes, given NRG Energy's financial position and liquidity constraints.

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 appraisals, prices for similar assets and present value techniques.

Special charges from continuing operations included in Operating Expenses include the following:

	December 31,		
	2002	2001	2000
	(In thousands)		
Asset impairments	$ 2,516,451	$ —	$ —
Severance and other charges (see Note 4)	111,315		
Total special charges	$2,627,766	$ —	$ —

Special Charges included the following asset impairments in 2002:

Project Name	Project Status	Pre-tax Charge(1)	Fair Value Basis
		(In thousands)	
Nelson	Terminated	$ 467,523	Similar asset prices
Pike	Terminated — chapter 7 involuntary bankruptcy petition filed in October 2002	402,355	Similar asset prices
Bourbonnais	Terminated	264,640	Similar asset prices
Meriden	Terminated	144,431	Similar asset prices
Brazos Valley	Foreclosure completed in January 2003	102,900	Projected cash flows
Kendall, Batesville & other expansion Projects	Terminated	120,006	Projected cash flows
Langage (UK)	Terminated	42,333	Estimated market price
Turbines & other costs	Equipment being marketed	701,573	Similar asset prices
Subtotal		2,245,761	
Operating projects			
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	Operating at a loss	28,851	Projected cash flows
Subtotal		270,690	
Total Impairment Charges		$ 2,516,451	

(1) Certain amounts have been combined from impairments disclosed in the September 30, 2002; Form 10-Q for turbines and other items.

All of these impairment charges relate to assets considered held for use under SFAS No. 144. Fair values determined by similar asset prices reflect NRG Energy's current estimate of recoverability from expected marketing of project assets. Fair values determined by estimated market price represent market bids or appraisals received that NRG Energy believes is best reflective of value. 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.

Additional asset impairments may be recorded by NRG Energy in periods subsequent to December 31, 2002, given the changing business conditions and the resolution of the pending restructuring plan. Management is unable to determine the possible magnitude of any additional asset impairments, but they could be material.

Note 4 — Severance and Other Charges

NRG Energy recorded severance charges of $25.6 million for employees terminated during 2002 and $18.4 million remains accrued. Approximately $2.5 million of the accrual was reported in the December 31, 2002 balance sheet as part of post retirement and other benefit obligations, the remaining amount is recorded as accrued salaries, benefits and related costs.

The following table summarizes the activity related to accrued salaries, benefits and related costs for the twelve months ended December 31, 2002:

	Accrued Salaries, Benefits and Related Costs
	(In thousands)
Balance at December 31, 2001	$ —
Accruals	23,102
Payments	(4,738)
Balance at December 31, 2002	$ 18,364

In addition, NRG Energy has engaged financial advisors, legal advisors, and other consultants to assist with restructuring NRG Energy's operations. Costs for these professional services are expensed as incurred.

Note 5 — Discontinued Operations and Assets Held for Sale

The following disclosures have been updated for discontinued operations related to McClain, TERI and NLGI which occurred during 2003.

Pursuant to the requirements of SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets,"* NRG Energy has classified and is accounting for certain of its assets as held-for-sale at December 31, 2002. SFAS No. 144 requires that assets held for sale 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 NRG Energy's management considered cash flow analyses, bids and offers related to those assets and businesses. This amount is included in loss from discontinued operations 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 its classification as such.

Discontinued Operations

Discontinued operations consist of the historical operations and net gains/losses related to our Crockett Cogeneration, Entrade, Killingholme, Csepel, Hsin Yu, Bulo Bulo, McClain, NEO Landfill Gas, Inc. (NLGI) and Timber Energy Resources, Inc. (TERI) projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. Sales of four of the projects closed during 2002 (Bulo Bulo, Csepel, Entrade and Crockett Cogeneration). One project, Killingholme, was sold in January 2003. During 2003, NRG Energy committed to a plan to sell McClain and closed on the sale of TERI. In addition, in May 2003 the project lender foreclosed on NRG Energy's ownership interests in the wholly owned operating subsidiaries of NLGI.

The financial results for all of these businesses have been accounted for as discontinued operations. Accordingly, operating results of 2002 and of prior periods have been restated to report the operations as discontinued.

Summarized results of operations of the discontinued operations were as follows:

Description	Year Ended December 31, 2002	Year Ended December 31, 2001	Year Ended December 31, 2000
		(In thousands)	
Operating revenues	$ 832,124	$607,455	$349,091
Operating & other expenses	1,456,438	571,946	321,344
Pre-tax (loss)/income from operations of discontinued components	(624,314)	35,509	27,747
Income tax (benefit)/expense	(10,442)	(5,893)	(5,622)
(Loss)/income from operations of discontinued components	(613,872)	41,402	33,369
Disposal of discontinued components — pre-tax gain (net)	2,814	—	—
Income tax (benefit)	(2,992)	—	—
Disposal of discontinued components — gain (net)	5,806	—	—
Net (loss)/income on discontinued operations	$ (608,066)	$ 41,402	$ 33,369

Operating and other expenses for 2002 shown in the table above included asset impairment charges of approximately $623.8 million, comprised of approximately $477.9 million for the Killingholme project, $121.8 million for the Hsin Yu project, $12.4 million for the NEO Landfill Gas, Inc. project and $11.7 million for the TERI project.

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

Discontinued Operations:	2002	2001	2000
		(Thousands of dollars)	
Current			
U.S.	$ 930	$ 409	$ 246
Foreign	(6,939)	(4,478)	(2,318)
	(6,009)	(4,069)	(2,072)
Deferred			
U.S.	(3,020)	332	225
Foreign	(1,413)	9,440	7,682
	(4,433)	9,772	7,907
Section 29 tax credits	—	(11,596)	(11,457)
	(10,442)	(5,893)	(5,622)
Disposal of discontinued components — gain (net)			
U.S.	(2,992)	—	—
Foreign	—	—	—
	(2,992)	—	—
Total income tax (benefit) expense	$(13,434)	$ (5,893)	$ (5,622)

The assets and liabilities of the discontinued operations are reported in the December 31, 2002 and 2001 balance sheets as held for sale. The major classes of assets and liabilities held for sale by geographic area are as follows at December 31:

	Power Generation				
2002	North America	Europe	Asia Pacific	Alternative Energy	Total
	(Thousands of dollars)				
Cash	$ 3,111	$ 23,172	$ 736	$ 430	$ 27,449
Restricted cash	5,094		3	—	5,097
Receivables, net	7,858	19,869	3,315	268	31,310
Derivative instruments valuation	—	29,795	—	—	29,795
Other current assets	2,330	14,768	8,203	557	25,858
Current assets — discontinued operations	$ 18,393	$ 87,604	$ 12,257	$ 1,255	$ 119,509
PP&E, net	$265,236	$231,048	$ 43,496	$ 11,962	$ 551,742
Derivative instruments valuation	—	87,804	—	—	87,804
Other non current assets	3,320	6,983	10,441	18,532	39,276
Non current assets — discontinued operations	$268,556	$325,835	$ 53,937	$30,494	$678,822
Current portion of long-term debt	$157,288	$360,122	$ 85,533	$ 7,658	$ 610,601
Accounts payable — trade	5,362	35,310	15,458	859	56,989
Other current liabilities	6,427	16,054	596	3,797	26,874
Current liabilities — discontinued operations	$169,077	$411,486	$101,587	$12,314	$694,464
Long-term debt	$ —	$ —	$ 73	$ —	$ 73
Deferred income tax	—	123,632	4,363	(2,102)	125,893
Derivative instruments valuation		12,302	—	—	12,302
Other non current liabilities	16	—	13,947	216	14,179
Non current liabilities — discontinued operations	$ 16	$135,934	$ 18,383	$ (1,886)	$ 152,447

	Power Generation					
2001	North America	Europe	Asia Pacific	Other Americas	Alternative Energy	Total
	(Thousands of dollars)					
Cash	$ 1,328	$ 74,499	$ 499	$ 3,579	$ 796	$ 80,701
Restricted cash	18,833	—	333	—	2,353	21,519
Receivables, net	53,659	56,978	5,072	7,718	1,272	124,699
Derivative instruments valuation	—	38,996	—	—	—	38,996
Other current assets	5,807	39,357	15,523	162	3,431	64,280
Current assets — discontinued operations	$ 79,627	$ 209,830	$ 21,427	$ 11,459	$ 7,852	$ 330,195
PP&E, net	$ 500,165	$ 916,768	$172,056	$68,940	$41,617	$1,699,546
Derivative instruments Valuation	—	83,588	—	—	—	83,588
Other non current assets	35,576	12,195	15,128	1	19,405	82,305
Non current assets — discontinued operations	$ 535,741	$1,012,551	$187,184	$68,941	$61,022	$1,865,439
Current portion of long-term debt	$394,382	$ 18,410	$ 18,185	$18,177	$ 6,389	$ 455,543
Accounts payable — trade	7,767	57,878	31,045	2,396	1,160	100,246
Other current liabilities	24,056	19,340	63	259	3,016	46,734
Current liabilities — discontinued operations	$426,205	$ 95,628	$ 49,293	$20,832	$10,565	$ 602,523
Long-term debt	$ —	$ 489,630	$ 72,297	$ —	$ 7,645	$ 569,572
Deferred income tax	863	142,053	4,707	6,950	123	154,696
Derivative instruments valuation	12,792	2,339	—	—	—	15,131
Other non current liabilities	14,020	—	33,843	3,802	4,184	55,849
Non current liabilities — discontinued operations	$ 27,675	$ 634,022	$110,847	$10,752	$11,952	$ 795,248

Included in other non-current assets held for sale is approximately $28.0 million (net of $3.9 million of amortization) of goodwill and $11.0 million (net of $1.9 million of amortization) of intangibles as of December 31, 2001. Included in other non-current assets held for sale as of December 31, 2002, is approximately $1.0 million of goodwill (net of $0.3 million of amortization) and $0.4 million (net of $0.5 million of amortization) of intangibles.

Bulo Bulo — In June 2002, NRG Energy began negotiations to sell its 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. NRG Energy accounted for the results of operations of Bulo Bulo as part of its power generation segment within the Other Americas region.

Crockett Cogeneration Project — In September 2002, NRG Energy announced that it had reached an agreement to sell its 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 NRG Energy 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. NRG Energy accounted for the results of operations of Crockett Cogeneration as part of its power generation segment within North America.

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

Killingholme — During third quarter 2002 NRG Energy recorded an impairment charge of $477.9 million. In January 2003, NRG Energy completed the sale of its interest in the Killingholme project to its lenders for a nominal value and forgiveness of outstanding debt with a carrying value of approximately $360.1 million at December 31, 2002. The sale of NRG Energy's interest in the Killingholme project and the release of debt obligations resulted in a gain on sale in the first quarter of 2003 of approximately $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. NRG Energy accounted for the results of operations of Killingholme as part of its power generation segment within Europe

Hsin Yu — During 2002 NRG Energy committed to sell its ownership interest in Hsin Yu located in Taiwan. During the third quarter of 2002, NRG Energy recorded an impairment charge of approximately $121.8 million for the Hsin Yu project. NRG Energy owns 60% with one other party owning the remaining minority interest. NRG Energy was negotiating to sell its interest in the project to the minority owner for a nominal value plus assumption of its future funding obligations. As of July 4, 2003, the minority owners withdrew from the negotiation process. NRG Energy is committed to pursue other sales alternatives. NRG Energy accounted for the results of operations of Hsin Yu as part of its power generation segment within Asia Pacific.

NLGI — During 2002, NRG Energy 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, NRG Energy recorded impairment charges of $23.6 million related to subsidiaries of NLGI and a charge of $14.5 million to write off its 50% investment in Minnesota Methane, LLC. Through April 30, 2003, NRG Energy and NLGI failed to make certain payments causing a default under NLGI's term loan agreements. In May 2003, the project lenders to the wholly-owned subsidiaries of NLGI and Minnesota Methane LLC foreclosed on NRG Energy's membership interest in the NLGI subsidiaries and NRG Energy's equity interest in Minnesota Methane LLC. There was no material gain or loss recognized as a result of the foreclosure.

NRG Energy may be contingently liable for up to approximately $50 million of future tax-related payments through 2007 to the owners of NLGI to the extent they generate Section 29 tax credits from future operations and the new project owner is unable to utilize such credits. Such obligations do not exist until the Section 29 tax credits are generated from ongoing operations. NRG Energy recorded a Section 29 tax credit obligation of approximately $6.5 million in connection with the foreclosure that represents the amount owed by NRG Energy for the tax credits generated by NLGI prior to the change in ownership. As a result of the change in ownership, NRG Energy is unable to estimate the total possible obligation or determine the probability of making such payments. NRG Energy accounts for the results of operations of NEO as part of its power generation segment within Alternative Energy.

McClain — In August 2003, NRG Energy announced that it had reached an agreement to sell its 77% interest in McClain Generating Station, a 520 MW combined-cycle, natural gas-fired facility located in Newcastle, Oklahoma to Oklahoma Gas & Electric Company. As part of the sales process, the project company NRG McClain LLC, filed for protection under Chapter 11 of the U.S. Bankruptcy Code. Upon completion, the sale will result in proceeds of approximately $160 million.

TERI — During 2002, NRG Energy recorded an impairment charge of $11.7 million based on a revised project outlook. In September 2003, NRG Energy 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 and a net loss of approximately $0.6 million.

Note 6 — Write Downs and Losses on Sales of Equity Method Investments

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

	December 31,		
	2002	2001	2000
	(In thousands)		
Write downs of equity method investments	$ 143,117	$ —	$ —
Losses on sales of equity method investments	57,355	—	—
Total	$200,472	$ —	$ —

Write Downs of Equity Method Investments

Loy Yang — Based on a third party market valuation and bids received in response to marketing the investment for possible sale, NRG Energy recorded a write down of its investment of approximately $53.6 million in the third quarter of 2002. This write-down reflected management's belief that the decline in fair value of the investment was other than temporary.

During the fourth quarter of 2002, NRG Energy and the other owners of the Loy Yang project engaged in a joint marketing of the project for possible sale. In connection with these efforts, a new independent market valuation analysis was completed. Based on the new market valuation and negotiations with a potential purchaser, NRG Energy recorded an additional write-down of its investment in the amount of $57.8 million in the fourth quarter of 2002. At December 31, 2002 the carrying value of the investment in Loy Yang is approximately $72.9 million. Accumulated other comprehensive loss at December 31, 2002 includes a reduction for foreign currency translation losses of approximately $76.7 million related to Loy Yang. The foreign currency translation losses will continue to be included as a component of accumulated other comprehensive (loss) until NRG Energy commits to a plan to dispose of its investment, as required by EITF Issue No. 01-05. NRG Energy accounts for the results of operations of its investment in Loy Yang as part of its power generation segment within the Asia Pacific region.

Kondapalli — On January 30, 2003, NRG Energy signed a sale agreement with the Genting Group of Malaysia (Genting) to sell NRG's 30% interest in Lanco Kondapalli Power Pvt Ltd (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. The sale to Genting has not yet been completed, although completion is expected in early second quarter of 2003. NRG Energy's equity in the project is $35.2 million, and the proposed transaction will result in an after-tax loss to NRG Energy. In the fourth quarter of 2002, NRG Energy wrote down its investment in Kondapalli by $12.7 million due to recent developments related to the sale which indicate an impairment of its book value that is considered by NRG Energy to be other than temporary. NRG Energy accounts for the results of operations of its investment in Kondapalli as part of its power generation segment within the Asia Pacific region.

Powersmith — During the fourth quarter of 2002, NRG Energy wrote down its investment in Powersmith in the amount of approximately $3.4 million due to recent developments which indicate impairment of its book value that is considered by NRG Energy to be other than temporary. NRG Energy accounts for the results of operations of these investments as part of its power generation segment within the North America region.

Other — During 2002, NRG Energy wrote down other equity investments in the amount of approximately $15.5 million due to recent developments which indicate impairment of their book value that is considered by NRG Energy to be other than temporary. NRG Energy accounted for the results of operations of these investments as part of its alternative energy segment.

Sales of Equity Method Investments

During 2002, NRG Energy entered into sales agreements to dispose of its non-controlling interests in seven projects that were accounted for by the equity method. As described below, six of these transactions closed during the year and one closed in January 2003. NRG Energy's share of each project's operating results through the respective disposal date is reported as equity in earnings from unconsolidated investments in the consolidated statement of operations. Losses on sales of equity method investments in the aggregate amount of approximately $57.4 million included in operating expenses is comprised of the net losses resulting from the seven disposal transactions.

Energy Development Limited — On July 25, 2002, NRG Energy announced it had signed an agreement for the sale of its ownership interests in an Australian energy company, Energy Development Limited (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 August 2002, NRG Energy received proceeds of $78.5 million (AUS), or approximately $43.9 million (U.S.), in exchange for its ownership interest in EDL with the closing of the transaction. During the second quarter of 2002, NRG Energy recorded a loss of approximately $14.2 million on the sale. NRG Energy accounted for the results of operations of its investment in EDL as part of its power generation segment within the Asia Pacific region.

Collinsville Power Station — In August 2002, NRG Energy announced that it had completed the sale of its 50% interest in the 192 MW Collinsville Power Station in Australia, to its partner, a subsidiary of Transfield Services Limited. NRG Energy's proceeds from the sale amounted to $8.6 million (AUS), or approximately $4.8 million (USD). NRG Energy recorded a loss of approximately $3.6 million (USD) from the sale during 2002. NRG Energy accounted for the results of operations of its investment in Collinsville Power Station as part of its power generation segment within the Asia Pacific region.

ECKG — In September 2002, NRG Energy announced that it had reached agreement to sell its 44.5% interest in the ECKG power station in connection with its Csepel power generating facilities, and its interest in Entrade, an electricity trading business, to Atel, an independent energy group headquartered in Switzerland. The transaction, closed in January 2003 and resulted in cash proceeds of $67.0 million and a net loss of $2.1 million. NRG Energy accounted for the results of operations of its investment in ECKG as part of its power generation segment within Europe.

Sabine River — In September 2002, NRG Energy agreed to transfer its indirect 50% interest in SRW Cogeneration LP (SRW) to its partner in SRW, Conoco, Inc. in consideration for Conoco's agreement to terminate or assume all of the obligations of NRG Energy in relation to SRW. SRW is a cogeneration facility in Orange County, Texas. NRG Energy recorded a loss of approximately $48.4 million from the transfer during the quarter ended September 30, 2002. The transaction closed on November 5, 2002. NRG Energy accounted for the results of operations of its investment in SRW as part of its power generation segment within North America.

Mt. Poso — In September 2002, NRG Energy agreed to sell its 39.5% indirect partnership interest in the Mt. Poso Cogeneration Company, a California limited partnership (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. NRG Energy accounted for the results of operations of its investment in Mt. Poso as part of its power generation segment within North America.

Kingston — In December, 2002, NRG Energy completed the sale of its 25% interest in Kingston Cogeneration LP, based near Toronto, Canada to Northland Power Income Fund. NRG Energy received net proceeds of $15.0 million resulting in a gain on sale of approximately $9.9 million. NRG Energy accounted for the results of operations of its investment in Kingston as part of its power generation segment.

NEO MESI LLC — On November 26, 2002, NRG Energy completed the transfer of its 50% interest in MESI Fuel Station No. 1, LLC (“MESI”) to Power Fuel Partners (“PFP”) in exchange for the assumption by PFP of all NEO MESI LLC’s (“NEO MESI”) obligations under the MESI operating agreement, currently estimated at $21.6 million. MESI Fuel Station No. 1 is a facility, which produces and sells synthetic fuel (coal briquettes) from the Ken West terminal in Catlettsburg, Kentucky. The transfer did not result in any significant impact on the results of operations. NRG Energy accounted for the results of operations of its investment in MESI Fuel Station No. 1 as part of the NEO Corporation.

Note 7 — Asset Acquisitions

During 2001, NRG Energy completed numerous acquisitions. These acquisitions were recorded using the purchase method of accounting. Accordingly, the purchase prices were allocated to assets acquired and liabilities assumed based on their estimated fair values at the date of acquisition. Operations of the acquired companies have been included in the operations of NRG Energy since the date of the respective acquisitions.

In January 2001, NRG Energy purchased from LS Power, LLC a 5,339 MW portfolio of operating projects and projects in construction and advanced development that are located primarily in the north central and south central United States. Each facility employs natural gas-fired, combined-cycle technology. Through December 31, 2005, NRG Energy also has the opportunity to acquire ownership interests in an additional 3,000 MW of generation projects developed and offered for sale by LS Power and its partners.

In March 2001, NRG Energy purchased from Cogentrix the remaining 430 MW, or 51.37% interest, in an 837 MW natural gas-fired combined-cycle plant in Batesville, Mississippi. NRG Energy acquired a 48.63% interest in the plant in January 2001 from LS Power.

In June 2001, NRG Energy purchased a 640 MW natural gas-fired power plant in Audrain County, Missouri from Duke Energy North America LLC.

In June 2001, NRG Energy closed on the construction financing for the Brazos Valley generating facility, a 633 MW gas-fired power plant in Fort Bend County, Texas that NRG Energy will build, operate and manage. At the time of the closing, NRG Energy also became the 100% owner of the project by purchasing STEAG Power LLC’s 50% interest in the project. During January 2003, NRG Energy transferred its interest in the Brazos Valley project to its creditors.

In June 2001, NRG Energy purchased 1,081 MW of interests in power generation plants from a subsidiary of Conectiv. NRG Energy acquired a 100% interest in the 784 MW coal-fired Indian River Generating Station located near Millsboro, Delaware, and in the 170 MW oil-fired Vienna Generating Station located in Vienna, Maryland. In addition, NRG Energy acquired 64 MW of the 1,711 MW coal-fired Conemaugh Generating Station located approximately 60 miles east of Pittsburgh, Pennsylvania and 63 MW of the 1,711 MW coal-fired Keystone Generating Station located approximately 50 miles east of Pittsburgh, Pennsylvania.

In June 2001, NRG Energy purchased a 389 MW gas-fired power plant and a 116 MW thermal power plant, both of which are located on Csepel Island in Budapest, Hungary, from PowerGen. In April 2001, NRG Energy also purchased from PowerGen its interest in Saale Energie GmbH and its 33.3% interest in MIBRAG BV. By acquiring PowerGen's interest in Saale Energie, NRG Energy increased its ownership interest in the 960 MW coal-fired Schkopau power station located near Halle, Germany from 200 MW to 400 MW.

By acquiring PowerGen's interest in MIBRAG, an integrated energy business in eastern Germany consisting primarily of two lignite mines and three power stations, and following MIBRAG's buy back of the shares NRG Energy acquired from PowerGen, NRG Energy increased its ownership of MIBRAG from 33.3% to 50%. The Washington Group International, Inc., owns the remaining 50% of MIBRAG.

In August 2001, NRG Energy acquired from Indeck Energy Services, Inc. an approximately 2,255 MW portfolio of operating projects and projects in advanced development, that are located in Illinois and upstate New York.

In August 2001, NRG Energy acquired Duke Energy's 77% interest in the approximately 520 MW natural-gas fired McClain Energy Generating Facility located near Oklahoma City, Oklahoma. The Oklahoma Municipal Power Authority owns the remaining 23% interest. The McClain facility commenced operations in June 2001.

In September 2001, NRG Energy acquired a 50% interest in TermoRio SA, a 1,040 MW gas-fired cogeneration facility currently under construction in Rio de Janeiro State, Brazil, from Petroleos Brasileiros SA (Petrobras). Commercial operation of the facility is expected to begin in March 2004. NRG Energy has the option to put its interest in the project back to Petrobras after March 2002 if by that time certain milestones have not been met, including final agreement on the terms of all project documents.

During fiscal year 2001, NRG Energy also acquired other minor interests in projects in Taiwan, India, Peru and the State of Nevada.

The respective purchase prices have been allocated to the net assets of the acquired entities as follows:

	December 31, 2001
	(In thousands)
Current assets	$ 307,654
Property plant and equipment	4,173,509
Non-current portion of notes receivable	736,041
Current portion of long term debt assumed	(61,268)
Other current liabilities	(99,666)
Long term debt assumed	(1,586,501)
Deferred income taxes	(149,988)
Other long term liabilities	(202,411)
Other non-current assets and liabilities	(181,473)
Total purchase price	2,935,897
Less — Cash balances acquired (excluding restricted cash)	(122,780)
Net purchase price	$ 2,813,117

In July 2001, NRG Energy signed agreements to acquire from Edison Mission Energy a 50% interest in the 375 MW Commonwealth Atlantic gas and oil-fired generating station located near Chesapeake, Virginia, and a 50% interest in the 110 MW James River coal-fired generating facility in Hopewell, Virginia. NRG

Energy closed the acquisition of the Commonwealth Atlantic and James River generating facilities in January 2002, for $11.2 million and $6.5 million, respectively.

Terminated Asset Acquisitions

Conectiv — In April 2002, NRG Energy terminated its purchase agreement with a subsidiary of Conectiv to acquire 794 MW of generating capacity and other assets, including an additional 66 MW of the Conemaugh Generating Station and an additional 42 MW of the Keystone Generating Station. The purchase price for these assets was approximately $230 million. No incremental costs were incurred by NRG Energy related to the termination of this agreement.

FirstEnergy — In November 2001, NRG Energy signed purchase agreements to acquire or lease a portfolio of generating assets from FirstEnergy Corporation. Under the terms of the agreements, NRG Energy agreed to pay approximately $1.6 billion for four primarily coal-fueled generating stations.

On July 2, 2002, the Federal Energy Regulatory Commission (FERC) issued an order approving the transfer of FirstEnergy generating assets to NRG Energy; however, the FERC conditioned the approval on NRG Energy's assumption of FirstEnergy's obligations under a separate agreement between FirstEnergy and the City of Cleveland. These conditions required FirstEnergy to protect the City of Cleveland in the event the generating assets are taken out of service. On July 16, 2002, FERC clarified that the condition would require NRG Energy to provide notice to the City of Cleveland and FirstEnergy if the generating assets were taken out of service and that other obligations remain with FirstEnergy.

On August 8, 2002, FirstEnergy notified NRG Energy that the agreements regarding the transfer of generating assets from FirstEnergy to NRG Energy had been cancelled. FirstEnergy cited the reason for canceling the agreements as an alleged anticipatory breach of certain obligations in the agreements by NRG Energy. On February 27, 2003, FirstEnergy gave NRG Energy notice that it was commencing arbitration against NRG Energy to determine whether NRG Energy is liable to FirstEnergy for failure to close the transaction. NRG Energy believes it has meritorious defenses against FirstEnergy's claim and intends to vigorously defend its position. No amount has been accrued for this contingency. Management is unable to predict the ultimate outcome of this matter, however, an adverse decision could be material to NRG Energy's financial position and results of operations. See Note 29 for additional discussion regarding the FirstEnergy settlement completed in 2003.

Note 8 — Property, Plant and Equipment

The major classes of property, plant and equipment at December 31, were as follows:

	2002	2001
	(In thousands)	
Facilities and equipment	$6,324,358	$ 5,072,816
Land and improvements	108,241	110,739
Office furnishings and equipment	67,086	27,958
Construction in progress	623,750	2,923,037
Total property, plant and equipment	7,123,435	8,134,550
Accumulated depreciation	(602,712)	(401,877)
Net property, plant and equipment	$6,520,723	$7,732,673

Included in construction in progress at December 31, 2002 is approximately $248.9 million related to turbines associated with cancelled projects.

Note 9 — Inventory

Inventory, which is stated at the lower of weighted average cost or market, at December 31, consists of:

	2002	2001
	(In thousands)	
Fuel oil	$ 51,442	$ 89,315
Coal	82,554	96,193
Kerosene	2,852	1,268
Spare parts	107,542	97,695
Emission credits	14,742	16,995
Natural gas	153	1,395
Other	6,300	4,513
Total inventory	$265,585	$307,374

Note 10 — Investments Accounted for by the Equity Method

NRG Energy has 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 NRG Energy 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 NRG Energy's equity-method investments which were in operation at December 31, 2002 is as follows:

Name	Geographic Area	Economic Interest
Gladstone Power Station	Australia	37.50%
Loy Yang Power A	Australia	25.37%
Lanco Kondapalli Power(1)	India	30.00%
MIBRAG GmbH	Europe	50.00%
Schkopau	Europe	41.67%
ECK Generating(1)	Europe	44.50%
El Segundo Power	USA	50.00%
Long Beach Generating	USA	50.00%
Encina	USA	50.00%
San Diego Combustion Turbines	USA	50.00%
Rocky Road Power	USA	50.00%
Mustang	USA	25.00%
Commonwealth Atlantic	USA	50.00%

(1) Pending disposition at December 31, 2002

Summarized financial information for investments in unconsolidated affiliates accounted for under the equity method as of and for the year ended December 31, is as follows:

	2002	2001	2000
		(In thousands)	
Operating revenues	$2,394,256	$3,070,078	$2,349,108
Costs and expenses	2,284,582	2,658,168	1,991,086
Net income	$ 109,674	$ 411,910	$ 358,022
Current assets	$1,069,239	$1,425,175	$1,000,670
Noncurrent assets	$6,853,250	7,009,862	7,470,766
Total assets	$7,922,489	$8,435,037	$8,471,436
Current liabilities	$1,075,785	$1,192,630	$1,094,304
Noncurrent liabilities	$3,861,285	4,533,168	4,306,142
Equity	$2,985,419	2,709,239	3,070,990
Total liabilities and equity	$7,922,489	$8,435,037	$8,471,436
NRG's share of equity	$1,171,726	$1,050,510	$ 973,261
NRG's share of net income	$ 68,996	$ 210,032	$ 139,364

West Coast Power LLC Summarized Financial Information

NRG Energy has a 50% interest in one company (West Coast Power LLC) that was considered significant as of December 31, 2001, as defined by applicable SEC regulations, and accounts for its investment using the equity method. The following table summarizes financial information for West Coast Power LLC, including interests owned by NRG Energy and other parties for the periods shown below:

Results of Operations

	Twelve Months Ended December 31, 2002	Twelve Months Ended December 31, 2001	Twelve Months Ended December 31, 2000
		(In millions)	
Operating revenues	$ 585	$ 1,562	$ 875
Operating income	48	345	278
Net income (pre-tax)	34	326	245

Financial Position

	December 31, 2002	December 31, 2001
	(In millions)	
Current assets	$ 255	$ 401
Other assets	532	659
Total assets	$ 787	$ 1,060
Current liabilities	$ 112	$ 138
Other liabilities	34	269
Equity	641	653
Total liabilities and equity	$ 787	$ 1,060

Note 11 — Related Party Transactions

NRG Energy and Xcel Energy have entered into material transactions and agreements with one another. Certain material agreements and transactions currently existing between NRG Energy and Xcel Energy are described below.

Operating Agreements

NRG Energy has two agreements with Xcel Energy for the purchase of thermal energy. Under the terms of the agreements, Xcel Energy charges NRG Energy for certain costs (fuel, labor, plant maintenance, and auxiliary power) incurred by Xcel Energy to produce the thermal energy. NRG Energy paid Xcel Energy $8.2 million, $7.1 million and $5.5 million in 2002, 2001 and 2000, respectively, under these agreements. One of these agreements expired on December 31, 2002 and the other expires on December 31, 2006.

NRG Energy has a renewable 10-year agreement with Xcel Energy, expiring on December 31, 2006, whereby Xcel Energy agreed to purchase refuse-derived fuel for use in certain of its boilers and NRG Energy agrees to pay Xcel Energy a burn incentive. Under this agreement, NRG Energy received $1.2 million, $1.6 million and $1.5 million from Xcel Energy, and paid $3.3 million, $2.8 million and $2.8 million to Xcel Energy in 2002, 2001 and 2000, respectively.

Administrative Services and Other Costs

NRG Energy has an administrative services agreement in place with Xcel Energy. Under this agreement NRG Energy reimburses Xcel Energy for certain overhead and administrative costs, including benefits administration, engineering support, accounting, and other shared services as requested by NRG Energy. In addition, NRG Energy employees participate in certain employee benefit plans of Xcel Energy as discussed in Note 16. NRG Energy reimbursed Xcel Energy in the amounts of $21.2 million, $12.2 million and $5.9 million, during 2002, 2001 and 2000, respectively, under this agreement.

Natural Gas Marketing and Trading Agreement

NRG Energy has an agreement with e prime, a wholly owned subsidiary of Xcel Energy, under which e prime provides natural gas marketing and trading from time to time and NRG Energy's request. NRG Energy paid $19.2 million to e prime in 2002.

Amounts owed to Xcel Energy

Included in accounts payable affiliate is approximately $42.9 of amounts owed to Xcel Energy at December 31, 2002.

Note 12 — Notes Receivable

Notes receivable consists primarily of fixed and variable rate notes secured by equity interests in partnerships and joint ventures. The notes receivable as of December 31, are as follows:

	2002	2001
	(Thousands of dollars)	
Investment in Bonds		
Audrain County, due December 2023, 10%	$239,930	$239,930
NRG Pike LLC Jackson County, MS bonds due May 2010, 7.1%	155,477	—
Investment in bonds	395,407	239,930
Notes Receivables		
Triton Coal Co., note due December 2003, non-interest bearing	3,000	—
O'Brien Cogen II note, due 2008, non-interest bearing	627	553
Southern Minnesota-Prairieland Solid Waste, note due 2003, 7%	12	24
Omega Energy, LLC, due 2004, 12.5%	4,145	4,095
Omega Energy, LLC, due 2009, 11%	1,533	1,533
Elk River — GRE, due December 31, 2008, non-interest bearing	1,837	2,098
Bangor Hydro Electric, due October 1, 2002, 5.45%	—	737
SET PERC Investment, LLC, due December 31, 2005, 7%	7,320	2,497
Notes receivables and bonds — non-affiliates	413,881	251,467
NEO notes to various affiliates due primarily 2012, prime +2%	9,538	21,086
Kladno Power (No. 1) B.V	2,442	—
Kladno Power (No. 2) B.V. notes to various affiliates, non-interest bearing	46,801	46,635
Termo Rio (via NRGenerating Luxembourg (No. 2) S.a.r.L, due 20 years after plant becomes operational, 19.5%	63,723	46,890
Saale Energie Gmbh, indefinite maturity date, 4.75%-7.79%	86,246	79,476
Northbrook Texas LLC, due February 2024, 9.25%	8,967	8,323
Notes receivable — affiliates	217,717	202,410
Reserve for Uncollectable Notes Receivable	(7,320)	—
Other		
Saale Energia GmbH, due August 31, 2021, 13.88% (direct financing lease)	366,417	318,949
Total	$990,695	$772,826

Saale Energie GmbH (SEG) has a long-term electricity supply contract with its sole customer, VEAG. SEG supplies its total available electricity capacity to VEAG. The contract has a term of 25 years. VEAG is obligated to pay on a monthly basis a price that covers the availability of power supply capacity and the operating costs incurred to produce electricity. During 2002 and the nine months subsequent to NRG Energy's consolidation of SEG in March 2001, approximately $46.0 million and $56.3 million, respectively, was recognized as revenue under this agreement. NRG Energy expects SEG to recognize revenues of approximately $40 million each year under this agreement.

Investment in bonds is comprised of marketable debt securities. These securities consist of municipal bonds of Audrain County, Missouri and Jackson County, Mississippi. The Audrain County bonds mature in 2023 and the Jackson County bonds mature in 2010. These investments in bonds are classified as held to maturity and are recorded at amortized cost. The carrying value of these bonds approximates fair value. Both the Audrain County bonds Jackson County bonds are pledged as collateral for the related debt owed to each county. As further described in Note 13 each of these transactions have offsetting obligations.

Note 13 — Debt and Capital Leases

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

	2002	2001
	(Thousands of dollars)	
NRG Debt:		
NRG Energy ROARS, due March 15, 2020, 7.97%	$ 257,552	$232,960
NRG Energy senior debentures (corporate units), due May 16, 2006, 6.5%	285,728	284,440
NRG Energy senior notes:		
February 1, 2006, 7.625%	125,000	125,000
July 15, 2006, 6.75%	340,000	340,000
June 15, 2007, 7.50%	250,000	250,000
June 1, 2009, 7.50%	300,000	300,000
September 15, 2010, 8.25%	350,000	350,000
April 1, 2011, 7.75%	350,000	350,000
November 1, 2003, 8.00%	240,000	240,000
April 1, 2031, 8.625%	340,000	340,000
April 1, 2031, 8.625%	160,000	160,000
NRG Debt secured solely by project assets:		
NRG Finance Company I LLC — Construction revolver, due May 2006, various interest rates	1,081,000	697,500
San Francisco Capital lease, due September, 2002, 20.8%	—	11
NRG Processing solutions, capital lease, due November 2004, 9.0%(1)	676	—
NRG Pike Energy LLC, due 2010.	155,477	—
NRG Energy Center San Diego, LLC promissory note, due June 2003, 8.0%	278	801
NRG Energy Center Pittsburgh LLC, due November 2004, 10.61%(1)	3,050	4,400
NRG Energy Center San Francisco LLC, senior secured notes, due November 2004, 10.61%(1)	2,310	3,761
Cahua SA, due various dates through November 2004, various interest rates(1)	21,386	29,106
Various NEO debt due 2005-2008, 9.35%	—	14,543
LSP Kendall Energy LLC, due September 2005, 2.65%	495,754	499,500
MidAtlantic Generating LLC, due October 2005, 4.625%	409,201	420,890
Camas Power Boiler LP, unsecured term loan, due June 30, 2007, 3.65%(1)	10,896	11,779
COBEE, due July 2007, various interest rates(1)	42,150	51,600

	2002	2001
	(Thousands of dollars)	
Camas Power Boiler LP, revenue bonds, due August 1, 2007, 3.38%(1)	6,965	9,130
NRG Brazos Valley LLC, due June 30, 2008, 6.75%	194,362	159,750
Energia Pacasmayo S.L.R., due various dates through January 2011, various interest rates(1)	21,878	26,014
Flinders Power Finance Pty, due September 2012, 6.14%-6.49%(1)	99,175	74,886
NRG Energy Center Minneapolis LLC. senior secured notes due 2013 and 2017, 7.12%-7.31%(1)	133,099	62,408
LSP Energy LLC (Batesville), due 2014 and 2025, 7.16%-8.16%(1)	314,300	321,875
PERC, due 2017 and 2018, 5.2%(1)	28,695	33,220
Saale Energie GmbH, Schkopau Capital lease, due 2021, various interest rates(1)	325,584	311,867
Audrain County, MO — Capital lease, due December 2023, 10%(1)	239,930	239,930
NRG South Central Generating LLC senior bonds, due various dates through September 15, 2024, various interest rates	750,750	763,500
NRG Northeast Generating LLC senior bonds, due various dates through December 15, 2024, various interest rates	556,500	610,000
NRG Peaker Finance Co. LLC	319,362	—
Subtotal	8,211,058	7,318,871
Less current maturities	7,026,771	44,611
Total	$1,184,287	$7,274,260

(1) NRG Energy has not reclassified the long term portions of these debt issuances to current as they are not currently callable within one year from the balance sheet date.

As of December 31, 2002, NRG Energy has failed to make scheduled payments on interest and/or principal on approximately $4.0 billion of its recourse debt and is in default under the related debt instruments. These missed payments also have resulted in cross-defaults of numerous other non-recourse and limited recourse debt instruments of NRG Energy. In addition to the missed debt payments, a significant amount of NRG Energy's debt and other obligations contain terms, which require that they be supported with letters of credit or cash collateral following a ratings downgrade. As a result of the downgrades that NRG Energy has experienced in 2002, NRG Energy estimates that it is in default of its obligations to post collateral of approximately $1.1 billion, principally to fund equity guarantees associated with its construction revolver financing facility, to fund debt service reserves and other guarantees related to NRG Energy projects and to fund trading operations. In early November 2002, NRG Energy presented a restructuring plan to its creditors.

In mid-December 2002, the NRG Energy bank steering committee submitted a counter-proposal to the restructuring plan. In January 2003, a new restructuring proposal was presented to the creditors and negotiations are ongoing. On March 26, 2003, Xcel Energy announced that its board of directors had approved a tentative settlement agreement with holders of most of NRG Energy's long-term notes and the steering committee representing NRG Energy's bank lenders. The settlement is subject to certain conditions, including the approval of at least a majority in dollar amount of the NRG Energy bank lenders and long-term noteholders and definitive documentation. There can be no assurance that such approvals will be obtained. The terms of the settlement call for Xcel Energy to make payments to NRG Energy over the next 13 months totaling up to $752 million for the benefit of NRG Energy's creditors in consideration for their waiver of an existing and potential claims against Xcel Energy. Under the settlement, Xcel Energy will make the following payments: (i) $350 million at or shortly following the consummation of a restructuring of NRG Energy's debt. It is expected this payment would be made prior to year-end 2003; (ii) $50 million on January 1, 2004. At Xcel Energy's option, it may fill this requirement with either cash or Xcel Energy common stock or any combination thereof; and (iii) $352 million in April 2004.

Absent an agreement on a comprehensive restructuring plan, NRG Energy will remain in default under its debt and other obligations, because it does not have sufficient funds to meet such requirements and obligations. As a result, the lenders will be able, if they so choose, to seek to enforce their remedies at any time, which would likely lead to a bankruptcy filing by NRG Energy. There can be no assurance that NRG Energy's creditors ultimately will accept any consensual restructuring plan, or that, in the interim, NRG Energy's lenders and bondholders will continue to forbear from exercising any or all of the remedies available to them, including acceleration of NRG Energy's indebtedness, commencement of an involuntary proceeding in bankruptcy and, in the case of certain lenders, realization on the collateral for their indebtedness.

Pending the resolution of NRG Energy's credit contingencies, NRG Energy has classified as current liabilities those long-term debt obligations that lenders have the ability to accelerate within twelve months of the balance sheet date.

Short Term Debt

In March 2002, NRG Energy's $500 million recourse revolving credit facility matured and was replaced with a $1.0 billion 364-day revolving line of credit, which matured on March 7, 2003. The facility is unsecured and provides for borrowings of "Base Rate Loans" and "Eurocurrency Loans". The Base Rate Loans bear interest at the greater of the Administrative Agent's prime rate or the sum of the prevailing per annum rates for overnight funds plus 0.5% per annum, plus an additional margin which varies from 0.375% to 0.50% based upon NRG Energy's utilization of the facility and its then-current senior debt credit rating. The Eurocurrency loans bear interest at an adjusted rate based on LIBOR plus an adjustment percentage, which varies depending on NRG Energy's senior debt credit rating and the amount outstanding under the facility. The credit agreement for this facility was amended in April 2002 to revise the interest coverage ratio covenant. As amended, the covenant requires NRG Energy to maintain a minimum interest coverage ratio of 1.75 to 1, as determined at the end of each fiscal quarter. The facility contains additional covenants that, among other things, restrict the incurrence of liens and require NRG Energy to maintain a net worth of at least $1.5 billion plus 25% of NRG Energy's consolidated net income from January 1, 2002 through the determination date. In addition, NRG Energy must maintain a debt to capitalization ratio of not more than 0.68 to 1.00 as defined in the credit agreement. The failure to comply with any of these covenants would be an Event of Default under the terms of the credit agreement. At December 31, 2002, NRG Energy had a $1.0 billion outstanding balance under this credit facility. As of December 31, 2002, the weighted average interest rate of such outstanding advances was 5.14% per year. NRG Energy missed a $7.6 million interest payment due on September 30, 2002, and as of that date, NRG Energy violated both the minimum net worth covenant and the minimum interest coverage ratio. NRG Energy also failed to make a fourth quarter interest payment of approximately $18.6 million due December 31, 2002. On February 27, 2003, ABN AMRO issued a notice on default on the corporate revolver financing facility, rendering the debt immediately due and payable. The recourse revolving credit facility matured on March 7, 2003 and the $1 billion drawn remains outstanding. Accordingly, the facility is in default.

NRG Energy's $125 million syndicated letter of credit facility contains terms, conditions and covenants that are substantially the same as those in NRG Energy's $1.0 billion 364-day revolving line of credit. During the second quarter of 2002, the letter of credit facility agreement was amended to incorporate the same covenant revisions and other amendments that had previously been made to the terms and conditions of NRG Energy's $1.0 billion revolving credit facility, including the addition of an interest coverage ratio covenant. As of December 31, 2002, NRG Energy violated both the minimum net worth covenant and the minimum interest coverage ratio. Accordingly, the facility is in default. NRG Energy had $110 million and $170 million in outstanding letters of credit as of December 31, 2002 and 2001, respectively.

As of December 31, 2001, NRG Energy, through its wholly owned subsidiary, NRG South Central Generating LLC, had outstanding approximately $40 million under a project level, non-recourse revolving credit agreement which matured in March 2002. During the period ended December 31, 2001, the weighted average interest rate of such outstanding advances was 4.46%. NRG South Central extended this facility in March 2002, for an additional 3 months, on substantially similar terms. NRG South Central paid down the outstanding balance in June 2002. The weighted average interest rate for the three months ended June 30, 2002 was 3.1%. As of December 31, 2002, this facility no longer exists.

In January 2001, NRG Energy entered into a bridge credit agreement with a final maturity date of December 31, 2001. Approximately $600 million was borrowed under this facility to partially finance NRG Energy's acquisition of the LS Power generation assets. In March 2001, the bridge credit facility was repaid with proceeds from NRG Energy's offering of common stock and equity units.

In June 2001, NRG Energy entered into a $600 million term loan facility. The facility was unsecured and provided for borrowings of base rate loans and Eurocurrency loans. The facility terminated on June 21, 2002. As of December 31, 2001, the aggregate amount outstanding under this facility was $600 million. During the period ended December 31, 2001 the weighted average interest rate of such outstanding advances was 3.94%. NRG Energy repaid this facility in March 2002, in connection with the closing of its new $1.0 billion unsecured corporate-level revolving line of credit and the receipt of $300 million of cash from Xcel Energy.

Long-term Debt and Capital Leases

Senior Securities

On March 13, 2001, NRG Energy completed the sale of 11.5 million equity units for an initial price of $25 per unit. The 11.5 million equity units sold included 1.5 million units sold pursuant to the underwriters' over-allotment option. NRG Energy received gross proceeds from the issuance of $287.5 million. Net proceeds from this issuance were $278.4 million after deducting underwriting discounts, commissions and estimated offering expenses. Each equity unit initially consists of a corporate unit comprising a $25 principal amount of NRG Energy's senior debentures and an obligation to acquire shares of NRG Energy common stock no later than May 18, 2004 at a price ranging from between $27.00 and $32.94. Approximately $4.1 million of the gross proceeds have been recorded as additional paid in capital to reflect the value of the obligation to purchase NRG Energy's common stock. Interest payments will be payable on the debentures quarterly in arrears on each February 16, May 16, August 16 and November 16, commencing May 16, 2001. Interest will be payable initially at an annual rate of 6.50% of the principal amount of $25 per debenture to, but excluding, February 17, 2004, or May 18, 2004. If the interest rate is not reset three business days prior to February 17, 2004 or three business days prior to May 18, 2004, the debentures will bear interest from February 17, 2004, or May 18, 2004, as applicable, at the reset rate to, but excluding, May 16, 2006. In addition, original issued discount will accrue on the debentures. The net proceeds were used in part to reduce amounts outstanding under NRG Energy's $600 million short-term bridge credit agreement, which was used to finance in part NRG Energy's acquisition of LS Power generation assets. As a result of the merger by Xcel Energy of NRG, holders of the NRZ equity units are no longer obligated to purchase shares of NRG common stock under the purchase contracts. Instead, holders of the equity units are now obligated to purchase a number of shares of Xcel Energy common stock upon settlement of the purchase contracts equal to the adjusted "settlement rate" or the adjusted "early settlement rate" as applicable. As a result of the short-form merger, the adjusted settlement rate is 0.4630 and the adjusted early settlement rate is 0.3795, subject to the terms and conditions of the purchase contracts set forth in a purchase contract agreement. On October 29, 2002, NRG Energy announced it would not make the November 16, 2002 quarterly interest payment on the

6.50% senior unsecured debentures due in 2006, which trade with the associated purchase contracts as NRG corporate units (NRZ). The 30-day grace period to make payment ended December 16, 2002, and NRG Energy did not make payment to the NRZ holders and, as a result, this issue is in default. In addition, NRG Energy did not make the February 17, 2003 quarterly interest payment. In the event of an NRG Energy bankruptcy, the obligation to purchase shares of Xcel Energy stock terminates.

In April 2001, NRG Energy issued $690 million of senior notes in two tranches. The first tranche of $350 million matures in April 2011 and bears an interest rate of 7.75%. The second tranche of $340 million matures in April 2031 and bears an interest rate of 8.625%. Interest on the notes is due semi-annually each April and October. The net proceeds of the issuance were used for repayment of short-term indebtedness incurred to fund acquisitions, for investments, general corporate purposes and to provide capital for future planned acquisitions.

In June 2001, NRG filed a shelf registration with the SEC to sell up to $2 billion in debt securities, common and preferred stock, warrants and other securities. Approximately $1.5 billion remains outstanding under this shelf registration filing as of December 31, 2002.

In July 2001, NRG Energy completed the sale of $500 million of unsecured senior notes under this shelf registration. The senior notes were issued in two tranches, the first tranche of $340 million of 6.75% Senior Notes is due July 2006 and the second tranche of $160 million of 8.625% Senior Notes is due April 2031. Interest payments are due semi-annually on January 15 and July 15 until maturity for the Senior Notes due 2006 and April 1 and October 1 until maturity for the Senior Notes due 2031. NRG received net proceeds from the sale of both series of notes of approximately $505.2 million, including interest on the senior notes due 2031, accrued from April 5, 2001. The net proceeds were used to repay all amounts outstanding under NRG's revolving credit agreement and for investments and other general corporate purposes and to provide capital for planned acquisitions. On October 1, 2002, NRG Energy failed to make a $13.6 million interest payment on the $350 million 7.75% senior unsecured notes due 2011, a $11.5 million interest payment due on the $340 million of 6.75% senior unsecured notes due 2006, and a $21.6 million payment on the combined $500 million of 8.625% senior unsecured notes due 2031. The 30-day grace period to make payment related to these issues has passed and NRG Energy did not make the required payments. NRG Energy is in default on these notes.

In March 2000, an NRG Energy sponsored non-consolidated pass through trust issued $250 million of 8.70% certificates due March 15, 2005. Each certificate represents a fractional undivided beneficial interest in the assets of the trust. Interest is payable on the certificates semi-annually on March 15 and September 15 of each year through 2005. The sole assets of the trust consist of £160 million (approximately $250 million on the date of issuance) principal amount 7.97% Reset Senior Notes due March 15, 2020 issued by NRG Energy. The Reset Senior Notes were used principally to finance NRG Energy's acquisition of the Killingholme facility. Interest is payable semi-annually on the Reset Senior Notes on March 15 and September 15 through March 15, 2005, and then at intervals and interest rates established in a remarketing process. If the Reset Senior Notes are not remarketed on March 15, 2005, they must be mandatorily redeemed by NRG Energy on such date. On September 16, 2002, NRG Pass-through Trust I failed to make a $10.9 million interest payment due on the $250 million bonds, as a consequence of NRG Energy failing to pay interest due on £160 million of 7.97% debt. The 30-day grace period to make payment related to this issue has passed and NRG Energy did not make the required payments, NRG Energy is in default on these bonds.

The NRG Energy senior notes are unsecured and are used to support equity requirements for projects acquired and in development. Interest is paid semi-annually.

The NRG Energy $125 million, $250 million, $300 million, $350 million, and $240 million senior notes are unsecured and are used to support equity requirements for projects acquired and in development. The interest is paid semi-annually and mature in February 2006, June 2007, June 2009, September 2010, and November 2013, respectively. On September 16, 2002, NRG Energy failed to make a $14.4 million interest payment due on $350 million of 8.25% senior unsecured notes due in 2010. On November 1, 2002, NRG Energy failed to make a $9.6 million interest payment due on $240 million of 8.0% senior unsecured notes due in 2013. On December 31, 2002, NRG Energy failed to make an $11.3 million interest payment due on $300 million of 7.5% senior unsecured notes due in 2009. On December 15, 2002, NRG Energy failed to make a $9.4 million interest payment due on $250 million of 7.5% senior unsecured notes due in 2007. On February 1, 2003, NRG Energy failed to make a $4.8 million interest payment due on the $125 million of 7.625% senior unsecured notes due 2006. The 30-day grace period to make payment related to these issues has passed and NRG Energy did not make the required payments, and NRG Energy is in default on these notes.

The $240 million NRG Energy Senior notes due November 1, 2013 are ROARS. November 1, 2003 is the first remarketing date for these notes. Interest is payable semi-annually on May 1, and November 1, of each year through 2003, and then at intervals and interest rates as discussed in the indenture. On the remarketing date, the notes must either be mandatorily tendered to and purchased by Credit Suisse Financial Products or mandatorily redeemed by NRG Energy at prices discussed in the indenture. The notes are unsecured debt that rank senior to all of NRG Energy's existing and future subordinated indebtedness. On October 16, 2002 NRG Energy entered into a Termination Agreement with the agent CSFB that, terminated the Remarketing Agreement. A termination payment of $31.4 million due on October 17, 2002 has not been paid.

Project Financings

In May 2001, NRG Energy's wholly-owned subsidiary, NRG Finance Company I LLC, entered into a $2 billion revolving credit facility. The facility was established to finance the acquisition, development and construction of power generating plants located in the United States and to finance the acquisition of turbines for such facilities. The facility provides for borrowings of base rate loans and Eurocurrency loans and is secured by mortgages and security agreements in respect of the assets of the projects financed under the facility, pledges of the equity interests in the subsidiaries or affiliates of the borrower that own such projects, and by guaranties from each such subsidiary or affiliate. Provided that certain conditions are met that assure the lenders that sufficient security remains for the remaining outstanding loans, the borrower may repay loans relating to one project and have the liens relating to that project released. Loans that have been repaid may be re-borrowed, as permitted by the terms of the facility. The facility terminates on May 8, 2006. The facility is non-recourse to NRG Energy other than its obligation to contribute equity at certain times in respect of projects and turbines financed under the facility. NRG Energy estimates the obligation to contribute equity to be approximately $819 million as of December 31, 2002. As of December 31, 2002 and 2001, the aggregate amount outstanding under this facility was $1.08 billion and $697.5 million, respectively. During the period ended December 31, 2002 and 2001, the weighted average interest rate of such outstanding advances was 4.92% and 4.83%, respectively. At December 31, 2002, interest and fees due in September 2002 were not paid and NRG Energy has suspended required equity contributions to the projects. Supporting construction and other contracts associated with NRG Energy's Pike and Nelson projects were violated by NRG Energy, in September and October 2002, respectively. NRG Energy is in default of this agreement and on November 6, 2002, lenders to NRG Energy accelerated the approximately $1.08 billion of debt under the construction revolver facility, rendering the debt immediately due and payable.

As part of NRG Energy's acquisition of the LS Power assets in January 2001, NRG Energy, through its wholly owned subsidiary, LSP Kendall Energy LLC, acquired a $554.2 million credit facility. The facility is non-recourse to NRG Energy and consists of a construction and term loan, working capital and letter of credit facilities. As of December 31, 2002 and 2001, there were borrowings totaling approximately $495.8 million and $499.5 million, respectively, outstanding under the facility at a weighted average annual interest rate of 3.19% and 5.12%, respectively. In May 2002, LSP-Kendall Energy, LLC received a notice of default from Societie General, the administrative agent under LSP-Kendall's Credit and Reimbursement Agreement dated November 12, 1999. The notice asserted that an event of default had occurred under the Credit and Reimbursement Agreement as a result of liens filed against the Kendall project by various subcontractors. In consideration of the borrower's implementation of a plan to remove the liens, and NRG Energy's indemnification pursuant to an Indemnity Agreement dated June 28, 2002, of the lenders to the Kendall project from any claims or damages relating to these liens or any dispute or action involving the projects EPC contractor, the administrative agent, with the consent of the required lenders under the Credit and Reimbursement Agreement, withdrew the notice of default and conditionally waived any default or event of default described therein. Discussions with the administrative agent regarding the liens continue. On January 10, 2003, NRG Energy received a notice of default from LSP Kendall's lenders indicating that certain events of default have taken place and that by issuing this notice of default the lenders have preserved all of their rights and remedies under the Credit Agreement and other Credit Documents. NRG Energy is negotiating a waiver to this default notice with the creditors to LSP Kendall.

Upon the acquisition of the LS Power assets, a subsidiary of NRG Energy assumed approximately $326 million of bonds outstanding originally issued to finance the construction of the Batesville generation plant. In May 1999, LSP Energy Limited Partnership (Partnership) and LSP Batesville Funding Corporation (Funding) issued two series of Senior Secured Bonds (Bonds) in the following total principle amounts: $150 million 7.16% Series A Senior Secured Bonds due 2014 and $176 million 8.160% Series B Senior Secured Bonds due 2025. Interest is payable semiannually on each January 15 and July 15. In March 2000, a registration statement was filed by Partnership and Funding and became effective. The registration statement was filed to allow the exchange of the Bonds for two series of debt securities (Exchange Bonds), which are in all material respects substantially identical to the Bonds. The Exchange Bonds are secured by substantially all of the personal property and contract rights of the Partnership and Funding. The Exchange Bonds are redeemable, at the option of Partnership and Funding, at any time in whole or from time to time in part, on not less than 30 nor more than 60 days prior notice to the holders of that series of Exchange Bonds, on any date prior to their maturity at a redemption price equal to 100% of the outstanding principal amount of the Exchange Bonds being redeemed and a make whole premium. In no event will the redemption price ever be less than 100% of the principal amount of the Exchange Bonds being redeemed plus accrued and unpaid interest thereon. Principal payments are payable on each January 15 and July 15 beginning July 15, 2001.

In March 2001, NRG Energy increased its ownership interest in Penobscot Energy Recovery Company (PERC), which resulted in the consolidation of its equity investment in PERC. As a result, the assets and liabilities of PERC became part of the assets and liabilities of NRG Energy. Upon completion of the transaction, NRG Energy recorded approximately $37.9 million of outstanding Finance Authority of Maine (FAME) Electric Rate Stabilization Revenue Refunding Bonds Series 1998 (FAME bonds) which were issued on PERC's behalf by FAME in June 1998. The face amount of the bonds that were initially issued was approximately $44.9 million and was used to repay the Floating Rate Demand Resource Revenue Bonds issued by the Town of Orrington, Maine on behalf of PERC. The FAME bonds are fixed rate bonds with yields ranging from 3.75% to 5.2%. The weighted average yield on the FAME bonds is approximately 5.1%. The FAME bonds are subject to mandatory redemption in annual installments of varying amounts through July 1, 2018. Beginning July 1, 2008 the FAME bonds are subject to redemption at the option of PERC at a redemption price equal to 102% through June 30, 2009, 101% for the period July 1, 2009 to June 30, 2010 and 100% thereafter, of the principal amount outstanding, plus accrued interest. The loan agreement with FAME contains certain restrictive covenants relating to the FAME bonds, which restrict PERC's ability to incur additional indebtedness, and restricts the ability of the general partners to sell, assign or transfer their general partner interests. The bonds are collateralized by liens on substantially all of PERC's assets. As of December 31, 2002, there remains $28.7 million of bonds outstanding.

On June 22, 2001, NRG MidAtlantic Generating LLC (MidAtlantic), a wholly owned subsidiary of NRG Energy, borrowed approximately $420.9 million under a five year term loan agreement (Agreement) to finance, in part, the acquisition of certain generating facilities from Conectiv. The Agreement terminates in November 2005 and provides for a total credit facility of $580 million. Interest is payable quarterly. The debt is guaranteed by MidAtlantic and its wholly owned subsidiaries. The Agreement provides for a variable interest rate at either the higher of the Prime rate or the Federal Funds rate plus 0.50%, or the London Interbank Offered Rate (LIBOR) of interest. During the period ended December 31, 2002 and 2001, the weighted average interest rate for amounts outstanding under the Agreement was 3.30% and 4.56%, respectively. MidAtlantic is obligated to pay a commitment fee of 0.375% of the unused portion of the credit facility. The Agreement requires MidAtlantic to comply with certain covenants concerning limitations on additional borrowings, sales of assets, capital expenditures, and payment of dividends or other distributions to shareholders.

In June 2001, NRG Energy through its wholly owned subsidiaries, Brazos Valley Energy LP and Brazos Valley Technology LP, entered into a $180 million non-recourse construction credit facility to fund the construction of the 600 MW Brazos Valley gas-fired combined cycle merchant generation facility located in Fort Bend County, Texas. On October 8, 2002, bank lenders and the project company executed amendments to the loan documents that provided for additional advances to fund certain construction costs. As of December 31, 2002, there existed an outstanding balance of $194.4 million under this credit agreement. The weighted average interest rate as of December 31, 2002 and 2001 was 4.41% and 4.61%, respectively. Interest is payable quarterly. On January 31, 2003, NRG Energy consented to the foreclosure of its Brazos Valley project by its lenders. As consequence of foreclosure, NRG Energy no longer has any interest in the Brazos Valley project, however, NRG Energy may be obligated to infuse additional amounts of capital to fund a debt service reserve account that had never been funded and may be obligated to make an equity infusion to satisfy a contingent equity agreement.

In connection with NRG Energy's acquisition of the COBEE facilities, NRG Energy recorded on its balance sheet approximately $56.3 million of non-recourse long-term debt that is due in 18 semi-annual installments of varying amounts beginning January 31, 1999 and ending July 31, 2007. The loan agreement provides an A Loan of up to $30 million and a B Loan of up to $45 million. Interest is payable semi-annual in arrears at a rate equal to 6-month LIBOR plus a margin of 4.5% on the A Loan and 6-month LIBOR plus a margin of 4.0% on the B Loan. The A Loan and the B Loan are collateralized by a mortgage on substantially all of COBEE's assets.

In August 2001, NRG Energy entered into a 364-day term loan of up to $296 million. The credit facility was structured as a senior unsecured loan and was partially non-recourse to NRG Energy. The proceeds were used to finance the McClain generating facility acquisition. In November 2001, the credit facility was repaid from the proceeds of a $181.0 million term loan and $8.0 million working capital facility entered into by NRG McClain LLC, with Westdeutsche Landesbank Girozentrale, New York branch, as agent (non-recourse to NRG Energy). The final maturity date of the facility is November 30, 2006. As of December 31, 2002 and 2001, the aggregate amount outstanding under this facility was $157.3 million and $159.9 million, respectively. During the period ended December 31, 2002 and 2001, the weighted average interest rate of such outstanding borrowings was 4.57% and 5.07%, respectively.

On September 17, 2002, NRG McClain LLC received notice from the agent bank that the project loan was in default as a result of the downgrade of NRG Energy and of defaults on material obligations under the Energy Management Services Agreement.

In connection with NRG Energy's acquisition of the Audrain facilities, NRG Energy has recognized a capital lease on its balance sheet within long-term debt in the amount of $239.9 million, as of December 31, 2002 and 2001. The capital lease obligation is recorded at the net present value of the minimum lease obligation payable. The lease terminates in May 2023. During the term of the lease only interest payments are due, no principal is due until the end of the lease. In addition, NRG Energy has recorded in notes receivable, an amount of approximately $239.9 million, which represents its investment in the bonds that the county of Audrain issued to finance the project. During December 2002, NRG Energy received a notice of a waiver of a $24.0 million interest payment due on the capital lease obligation.

In connection with NRG Energy's purchase of PowerGen's interest in Saale Energie GmbH, NRG Energy has recognized a non-recourse capital lease on its balance sheet within long-term debt in the amount of $333.9 million and $311.9 million, as of December 31, 2002 and 2001, respectively. The capital lease obligation is recorded at the net present value of the minimum lease obligation payable over the lease's remaining period of 20 years. In addition, a direct financing lease was recorded in notes receivable in the amount of approximately $366.4 million and $318.9 million, as of December 31, 2002 and 2001, respectively.

In July 2002, NRG Energy Center Minneapolis LLC (ECM), an indirect wholly owned subsidiary of NRG Energy, entered into an agreement allowing it to issue senior secured promissory notes in the aggregate principal amount of up to $150 million. In July 2002, under this agreement, ECM issued $75 million of bonds in a private placement. Two series of notes were issued in July 2002, the $55 million Series A-Notes dated July 3, 2002, which matures on August 1, 2017 and bears an interest rate of 7.25% per annum and the $20 million Series B-Notes dated July 3, 2002, which matures on August 1, 2017 and bears an interest rate of 7.12% per annum. NRG Thermal LLC, a wholly owned subsidiary of NRG Energy, which owns 100% of ECM, pledged its interests in all of its district heating and cooling investments throughout the United States as collateral. NRG Thermal and ECM are required to maintain compliance with certain financial covenants primarily related to incurring debt, disposing of assets, and affiliate transactions. NRG Thermal and ECM were in compliance with these covenants at December 31, 2002.

On October 30, 2002 NRG Energy failed to make $3.1 million in payments under certain Non-Operating Interest Acquisition agreements. As a result, NEO Corporation, a direct wholly-owned subsidiary of NRG Energy and NEO Landfill Gas, Inc., an indirect wholly-owned subsidiary of NRG Energy, failed to make approximately $1.4 million in payments under the Amended and Restated Construction, Acquisition and Term Loan Agreement, dated July 6, 1998. Also, the subsidiaries of NEO Corporation and NEO Landfill Gas, Inc. failed to make approximately $2 million in payments pursuant to various Site Development Operations and Coordination Agreements. NRG Energy received an extension until November 19, 2002 with respect to NEO Landfill Gas, Inc. to make payments under such agreements and such payments were made during the extension period. The payments relating to NEO Corporation were not made and the loan was due and payable on December 20, 2002. A letter of credit was drawn to pay the NEO Corporation loan in full on December 23, 2002. As of December 31, 2002, NEO Landfill Gas, Inc. was in default under the Amended and Restated Construction, Acquisition and Term Loan Agreement dated July 6, 1998 due to the failure to meet the insurance requirements under the loan document. On January 30, 2003 NRG Energy, Inc. failed to make $2.7 million in payments under certain Non-Operating Interest Acquisition agreements. As a result, NEO Landfill Gas, Inc. failed to make its payment due on January 30, 2003 under the Amended and Restated Construction Acquisition and Term Loan Agreement dated July 6, 1998 and the subsidiaries of NEO Landfill Gas failed to make their payments pursuant to various Site Development and Operations Coordination Agreements.

The Camas Power Boiler LP notes are secured principally by its long-term assets. In accordance with the terms of the note agreements, Camas Power Boiler LP is required to maintain compliance with certain financial covenants primarily related to incurring debt, disposing of assets, and affiliate transactions. Camas Power Boiler was in compliance with these covenants at December 31, 2002.

On February 22, 2000, NRG Northeast Generating LLC (NRG Northeast), an indirect, wholly-owned subsidiary of NRG Energy, issued $750 million of project level senior secured bonds, to refinance short-term project borrowings and for certain other purposes. The bond offering included three tranches: $320 million with an interest rate of 8.065% due in 2004, $130 million with an interest rate of 8.842% due in 2015 and

$300 million with an interest rate of 9.292% due in 2024. Interest and principal payments are due semi-annually. The bonds are jointly and severally guaranteed by each of NRG Northeast's subsidiaries. The bonds are secured by a security interest in NRG Northeast's membership or other ownership interests in the guarantors and its rights under all inter-company notes between NRG Northeast and the guarantors. In December 2000, NRG Northeast exchanged all of its outstanding bonds for bonds registered under the Securities Act of 1933. As of December 31, 2002 and 2001, there remains $556.5 million and $610 million of outstanding bonds, respectively. On December 15, 2002, NRG Northeast failed to make $24.7 million interest and $53.5 million principal payments. NRG Northeast Generating had a 15-day grace period to make payment. On December 27, 2002, NRG Northeast made the $24.7 million interest payment due on the NRG Northeast bonds, but failed to make the $53.5 million principal payment. As a result, the payment default associated with its failure to make principal payments when they come due is currently in effect. NRG Northeast also failed to make a debt service reserve account cash deposit within 30 days of NRG Energy's credit rating downgrade in July 2002. In addition, NRG Northeast is also in default of its debt covenants because of the lapse of the 60 day grace period regarding the necessary dismissal of an involuntary bankruptcy proceeding.

In March 2000, NRG South Central Generating LLC (NRG South Central), an indirect wholly owned subsidiary of NRG Energy, issued $800 million of senior secured bonds in a two-part offering, to finance its acquisition of the Cajun generating facilities. The first tranche was for $500 million with a coupon of 8.962% and a maturity of 2016. The second tranche was for $300 million with a coupon of 9.479% and a maturity of 2024. Interest and principal payments are due semi-annually. The bonds are secured by a security interest in NRG Central U.S. LLC's and South Central Generating Holding LLC's membership interests in NRG South Central and NRG South Central's membership interests in Louisiana Generating and all of the assets related to the Cajun facilities including its rights under a guarantor loan agreement and all inter-company notes between it and Louisiana Generating, and a revenue account and a debt service reserve account. In January 2001, NRG South Central exchanged all of its outstanding bonds for bonds registered under the Securities Act of 1933. As of December 31, 2002 and 2001, there remains $750.8 million and $763.5 million of outstanding bonds, respectively. On September 15, 2002, NRG South Central missed a $47 million principal and interest payment. The 15-day grace period to make payment related to this issue passed and NRG South Central did not make the required payments. In January 2003, the South Central Generating bondholders unilaterally withdrew $35.6 million from the restricted revenue account, relating to the September 15, 2002, interest payment and fees. On March 17th, 2003 South Central bondholders were paid $34.4 million due in relation to the semi-annual interest payment and the $12.8 million principal payment was deferred. NRG South Central remains in default on these notes.

In September 2000, Flinders Power Finance Pty (Flinders Power), an Australian wholly owned subsidiary, entered into a twelve year AUD $150 million promissory note (US $81.4 million at September 2000). As of December 31, 2002 and 2001, there remains $80.5 million and $74.9 million outstanding under this facility, respectively. The interest has fixed and variable components. At December 31, 2002 and 2001, the effective interest rate was 6.49% and 5.89%, respectively and is paid semi annually. Principal payments commence in 2006 and the facility will be fully paid in 2012. In March 2002, Flinders Power entered into a 10 year AUD $165 million (US$85.4 million at March 2002) floating rate promissory note for the purpose of refurbishing the Flinders Playford generating station. As of December 31, 2002, the Company had drawn $18.7 million (AUD $33 million) of this facility. The interest rate has fixed and variable components. The effective interest rate at December 31 ,2002 was 6.14%, and is paid semi annually. Upon NRG Energy's credit rating downgrade in 2002, there existed a potential default under these agreements related to the funding of reserve funds. Flinders has worked with the Flinders Banks since the downgrade and has signed a series of consecutive standstill agreements, the last standstill agreement expires in March 2003 unless otherwise agreed or extended.

In June 2002, NRG Peaker Finance Company LLC (NRG Peaker), an indirect wholly owned subsidiary of NRG Energy, completed the issuance of $325 million of Series A Floating Rate Senior Secured Bonds due 2019. The bonds bear interest at a floating rate equal to three-months USD-LIBOR — BBA plus 1.07%. Interest on the bonds is payable on March 10, June 10, September 10 and December 10 of each year, commencing on September 10, 2002. Scheduled principal payments of $8.0 million, $10.5 million, $4.3 million, $6.8 million, $11.2 million and $278.6 million are due on December 10 of 2003, 2004, 2005, 2006, 2007 and thereafter through June 2019, respectively. The final scheduled repayment of principal is due on June 10, 2019. The bonds may be redeemed at any time prior to maturity at a price that, in certain circumstances, will include a redemption premium. The initial bond proceeds of $325 million were used to make loans to affiliates which own natural-gas fired “peaker” electric generating projects located in either Louisiana or Illinois. The project owners used the proceeds of the loans to (1) reimburse NRG Energy for construction and/or acquisition costs for the peaker projects previously paid by NRG Energy, (2) pay to XL Capital Assurance (XLCA) the premium for the Bond Policy, (3) provide funds to NRG Peaker to collateralize a portion of NRG Energy’s contingent guaranty obligations and (4) pay transaction costs incurred in connection with the offering of the bonds (including reimbursement of NRG Energy for the portion of such costs previously paid by NRG Energy). The Bond Policy is a financial guaranty insurance policy that unconditionally and irrevocably guaranties payment of scheduled principal and interest payments on the Bonds. The Bond Policy does not, however, guaranty the payment of principal of or interest on the bonds prior to the applicable scheduled payment dates, unless XLCA elects to make such payments. The bonds are secured by a pledge of membership interests in NRG Peaker and a security interest in all of its assets, which initially consist of notes evidencing loans to the affiliate project owners. The project owners’ jointly and severally guaranty the entire principal amount of the bonds and interest on such principal amount. The project owner guaranties are secured by a pledge of the membership interest in three of five project owners and a security interest in substantially all of the project owners’ assets related to the peaker projects, including equipment, real property rights, contracts and permits. NRG Energy has entered into a contingent guaranty agreement in favor of the collateral agent for the benefit of the secured parties, under which it agreed to make payments to cover scheduled principal and interest payments on the bonds and regularly scheduled payments under the interest rate swap agreement, to the extent that the net revenues from the peaker projects are insufficient to make such payments, in specified circumstances. This financing contains a cross-default provision related to the failure by NRG Energy to make payment of principal, interest or other amounts due on debt for borrowed money in excess of $50 million, a covenant that was violated in October 2002. In addition, in 2002 mechanics liens were placed against the Bayou Cove facility resulting in an additional default. On October 22, 2002, XL Capital issued a notice of default on the Peaker financing facility. On December 10, 2002, $16.0 million in interest, principal, and swap payments were made from restricted cash accounts. As a result, $319.4 million in principal remains outstanding as of December 31, 2002.

NRG Peaker has also entered into an interest rate swap agreement pursuant to which it agreed to make fixed rate interest payments and receive floating rate interest payments. The interest rate swap counter-party will have a security interest in the collateral for the bonds and the collateral for the project owner guaranties. Net payments to be made by NRG Peaker under the interest rate swap agreement will be guaranteed pursuant to a separate financial guaranty insurance policy, the issuer of which will have a security interest in the collateral for the bonds and the collateral for the project owner guaranties. NRG Peaker was in compliance with this agreement at December 31, 2002.

LSP-Pike Energy LLC entered into a loan agreement with the Mississippi Business Finance Corporation to construct its power generation facility in Pike County, Mississippi. The Mississippi Business Finance Corporation financed the loan agreement by the issuance of Industrial Revenue Bonds (Series 2002). NRG Finance Company LLC, an affiliate of LSP-Pike Energy LLC, purchased the Series 2002 bonds. The principal and the interest on the loan agreement is due and payable as of January 1, 2010 and bears a variable interest rate equivalent to the interest rate payable on the loan funds used to finance the bond purchase by NRG

Finance Company I LLC. These bonds are subject to a subordination agreement between NRG Finance Company I LLC, as purchaser, LSP-Pike Energy LLC, and Credit Suisse First Boston, as administrative agent to a senior claim, so that in the case of insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings, and even in the event of any proceedings for voluntary liquidation, dissolutions, or other winding up of the company, then the holders of the senior claims shall be entitled to receive payment in full or cash equivalents of all principal, interest, charges and fees on all senior claims before the purchaser is entitled to receive any payment on account of the principal of or interest on these bonds. As of October 17, 2002, the United States Bankruptcy Court for the Southern District of Mississippi granted an order of relief to the debtor under the US bankruptcy laws, thus, forcing LSP-Pike Energy LLC into default and cessation of all benefits granted under the terms of the loan agreement and issuance of the bonds.

Annual maturities of long-term debt and capital leases for the years ending after December 31, 2002 are as follows:

	Total
	(Thousands of dollars)
2003 (Due or callable)	$7,026,771
2004	68,125
2005	79,036
2006	75,430
2007	70,331
Thereafter	891,365
Total	$ 8,211,058

Future minimum lease payments for capital leases included above at December 31, 2002 are as follows:

	(Thousands of dollars)
2003	$ 92,409
2004	88,677
2005	84,653
2006	80,974
2007	77,295
Thereafter	1,029,241
Total minimum obligations	1,453,249
Interest	(887,059)
Present value of minimum obligations	566,190
Current portion	(26,855)
Long-term obligations	$ 539,335

Total net book value related to the assets recorded with respect to NRG Energy's capital leases at December 31, 2002 and 2001 was $258.2 million and $334.6 million, net of $2.3 million and $0 of accumulated amortization, respectively.

Note 14 — Guarantees

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

NRG Energy is directly liable for the obligations of certain of its project affiliates and other subsidiaries pursuant to guarantees relating to certain of their indebtedness, equity and operating obligations. In addition, in connection with the purchase and sale of fuel, emission credits and power generation products to and from third parties with respect to the operation of some of NRG Energy's generation facilities in the United States, NRG Energy may be required to guarantee a portion of the obligations of certain of its subsidiaries. Additionally, as a result of the downgrades of NRG Energy's unsecured debt ratings, the Company is required to post cash collateral in the amount of $1.1 billion, however, NRG Energy has been unable to do so.

As of December 31, 2002 and 2001, NRG Energy's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries were as follows:

Description	2002	2001
	(In thousands)	
Guarantees of subsidiaries (including cash collateral calls)	$ 1,587,022	$721,730
Standby letters of credit	110,676	170,287
Total guarantees	$1,697,698	$892,017

As of December 31, 2002, the nature and details of NRG's guarantees were as follows:

Project/Subsidiary	Guarantee/ Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
	(in thousands)			
Astoria/ Arthur Kill	Indeterminate	Performance	None stated	Nonperformance
Bourbonnais	$ 15,000	Purchase of turbines	None stated	Nonperformance
Brazos Valley	$ 72,600	Equity Infusion	December 1, 2006	Equity not injected
Brazos Valley	$ 7,300	Payment obligations under Interconnection Agreement	None stated	Nonpayment
Brazos Valley	$ 300	Payment obligations under Interconnection Agreement	None stated	Nonpayment
Cahua S.A. and Energia Pacasmayo S.R.L.	$ 4,398	Obligations under credit agreement	None stated	Credit Agreement default
Commonwealth Atlantic Limited Partnership	$ 2,000	Invoice payment	April 1, 2003	Nonpayment
Conectiv	$ 2,400	Closure and post-closure care of landfill	None stated	Subsidiary failure to maintain landfill
Elk River Resource Recovery	$ 17,000	Defaults on bond payments	January 1, 2006	NSP default on bond payments
Enfield	$ 3,555	Obligations under credit agreement	None stated	Credit Agreement default

Project/Subsidiary	Guarantee/ Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
	(in thousands)			
Flinders	$ 24,000	Employee separation packages, superannuation and retention payments	None stated	Nonpayment
Flinders	Indeterminate	Goods & Services Tax liability	None stated	Nonpayment
Flinders	$ 45,000	Post lease obligations	None stated	Failure to meet obligations
Flinders	$ 4,800	Purchase of gas	December 31, 2010	Failure to purchase gas
Flinders	Indeterminate	Performance	December 31, 2018	Nonperformance
Flinders	$ 10,275	Superannuation reserve	September 7, 2005	Credit Agreement default
Flinders	$ 11,322	Debt service reserve guarantee	None stated	Credit Agreement default
Gladstone	$ 18,445	Extraordinary operational breach	None stated	Nonperformance
Ilion	$ 11,478	Payment under lease agreement	March 25, 2004	Nonpayment
Killingholme	$ 21,300	Debt service reserve guarantee	None stated	Credit Agreement default
McClain LLC	$ 4,744	Debt service reserve guarantee	November 1, 2006	Credit Agreement default
Mid-Atlantic (Conectiv)	$ 23,389	Debt service reserve guarantee	November 13, 2005	Credit Agreement default
NEGEN LLC	$ 37,000	Performance	December 31, 2003	Nonperformance
NEGEN LLC	$ 40,129	Debt service reserve guarantee	December 15, 2024	Credit Agreement default
NEO California Power LLC	$ 5,832	Reliability agreement	Not stated	Nonperformance
NRG Finance Company I LLC	$ 819,000	Equity Infusion	None stated	Equity not injected
Power Marketing, Inc	$ 133,925	Performance	None stated	Nonperformance
South Central Generating LLC	$ 46,595	Debt service reserve guarantee	September 15, 2024	Credit Agreement default
West Coast LLC	$ 5,000	Invoice payment	None stated	Nonpayment
West Coast LLC	$ 40,000	Equity infusion	None stated	Equity not injected
West Coast LLC	Indeterminate	Asset Sales Agreement	None stated	Nonperformance
Peaker Finance Co	$ 34,500	Guarantee for early termination	June 18, 2019	Nonperformance
Peaker Finance Co	$ 30,380	Experience account Shortfall	June 18, 2019	Nonperformance
Peaker Finance Co	$ 7,500	Project Completion	December 31, 2003	Nonperformance
ECKG	$ 17,355	Obligations under purchase agreement	2003	Nonperformance of subsidiary obligation
ECKG	$ 4,500	Operations & Maintenance Agreement	2010	Nonperformance of subsidiary obligation
Entrade	$ 8,000	Obligations under the SPA	December 13, 2007	Nonperformance of subsidiary obligation
Csepel	$ 50,000	Obligations under the SPA	December 13, 2007	Nonperformance of subsidiary obligation
Bulo Bulo	$ 8,000	Obligations under the SPA	December 13, 2007	Nonperformance of subsidiary obligation

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

Note 15 — Income Tax

NRG Energy and its subsidiaries filed a consolidated federal income tax return through June 3, 2002, when Xcel Energy completed its exchange offer for the 26% of NRG Energy's shares that had been previously publicly held. Starting June 4, 2002, NRG Energy and subsidiaries will file separate income tax returns for each NRG Energy entity that is treated as a corporation for income tax purposes. Thus, the income tax provision for NRG Energy is based on a consolidated NRG Energy group through June 3, 2002, and separate corporate tax returns starting June 4, 2002.

The provision (benefit) for income taxes for the years ended December 31, consists of the following:

	2002	2001	2000
	(Thousands of dollars)		
Current			
U.S.	$ 10,413	$ 28,893	$ 88,774
Foreign	18,973	11,627	1,704
	29,386	40,520	90,478
Deferred			
U.S.	(190,374)	31,441	31,086
Foreign	(2,248)	4,529	(578)
	(192,622)	35,970	30,508
Tax credits recognized	—	(37,192)	(22,626)
Total income tax (benefit)	$(163,236)	$ 39,298	$ 98,360
Effective tax rate	5.4%	14.9%	39.7%

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

	2002	2001	2000
	(Thousands of dollars)		
U.S.	$(2,898,906)	$ 185,643	$226,249
Foreign	(169,843)	18,656	3,419
	$(3,068,749)	$204,299	$229,668

The components of the net deferred income tax liability at December 31 were:

	2002	2001
	(Thousands of dollars)	
Deferred tax liabilities:		
Differences between book and tax basis of property, other than impairments	$ 263,038	$ 380,153
Investments in projects	(7,964)	30,036
Goodwill	1,757	2,116
Net unrealized gains on mark to market transactions	37,800	17,591
Other	8,807	2,316
Total deferred tax liabilities	$ 303,438	$432,212
Deferred tax assets:		
Deferred compensation, accrued vacation and other reserves	53,933	23,555
Development costs	11,079	5,741
Foreign tax loss carryforwards	16,088	90,251
Differences between book and tax basis of contracts	19,806	82,972
Difference between book and tax basis of property due to impairments	702,905	—
AMT credit carryforward	23,536	—
Domestic tax loss carry forwards	456,460	—
Other	1,155	5,274
Total deferred tax assets (before valuation allowance)	1,284,962	207,793
Valuation allowance	(1,073,158)	(66,621)
Net deferred tax assets	$ 211,804	$ 141,172
Net deferred tax liability	$ 91,634	$ 291,040

As of December 31, 2002, NRG Energy provided a valuation allowance to account for potential limitations on utilization of U.S. and Foreign net operating loss carryforwards of approximately $1,113.3 million and $81.9 million, respectively. The net operating loss carryforwards expire between 2003 and 2021. NRG Energy also provided a valuation allowance for other U.S. deferred income tax assets of approximately $521.8 million. The increase in U.S. deferred income tax assets is primarily due to the recognition of impairment charges. During the year ended December 31, 2002, the valuation allowance increased $1,006.5 million due to the increases in net operating loss carryforwards and deferred income tax assets for which NRG Energy is unable to conclude that there will be sufficient taxable earnings in future periods to offset the tax benefits.

As of December 31, 2002, a net deferred tax asset of approximately $33 million was recorded relating to the investment West Coast Power. On a separate company basis, there will be sufficient taxable earnings in future periods for utilization of the tax benefits.

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

	2002		2001	
	(Thousands of dollars)			
(Loss)/ Income before taxes	$(3,019,452)		$263,100	
Tax at 35%	(1,056,808)	35.0%	92,085	35.0%
State taxes (net of federal benefit)	(167,405)	5.5%	7,598	2.9%
Foreign operations	(55,435)	1.8%	(88,601)	-33.7%
Tax credits	0	0.0%	(37,192)	-14.1%
Limitation on tax benefits	1,073,158	-35.5%	66,621	25.3%
Permanent differences, reserves, other	43,254	-1.4%	(1,213)	-0.5%
Income tax (benefit) expense	$ (163,236)	5.4%	$ 39,298	14.9%

For the year ended December 31, 2002, income tax expense was $(163.2) million, compared to an income tax expense of $39.3 million for the year ended December 31, 2001, a decrease of $202.5 million. The decrease in tax expense compared to 2001 was primarily due to the reduction in domestic earnings. For the year ended December 31, 2002, NRG Energy's overall effective tax rate was 5.4%, compared to 14.9% for the same period in 2001.

The effective income tax rate for the year ended December 31, 2002 differs from the statutory federal income tax rate of 35% primarily due to limitation on tax benefits. The effective income tax rate for the year ended December 31, 2001 differs from the statutory federal income tax rate of 35% primarily due to state tax, foreign tax and tax credits as shown above.

As of December 31, 2001 NRG Energy management intended to reinvest the earnings of foreign operations to the extent the earnings were subject to current U.S. income taxes. Accordingly, U.S. income taxes and foreign withholding taxes were not provided on a cumulative amount of unremitted earnings of foreign subsidiaries of approximately $345 million December 31, 2001. As of December 31, 2002 NRG Energy management has revised its strategy and no longer intends to indefinitely reinvest the full amount of earnings of foreign operations. However, no U.S. income tax benefit has been provided on the cumulative amount of unremitted losses of ($339.7) million at December 31, 2002 due to the uncertainty of realization.

Note 16 — *Benefit Plans and Other Postretirement Benefits*

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

In addition, NRG Energy provides postretirement health and welfare benefits (health care and death benefits) for certain groups of its employees. Generally, these are groups that were acquired in recent years and for whom prior benefits are being continued (at least for a certain period of time or as required by union contracts). Cost sharing provisions vary by acquisition group and terms of any applicable collective bargaining agreements. Certain former NRG Energy retirees are covered under the legacy Xcel Energy plan, which was terminated for non-bargaining employees retiring after 1998 and for bargaining employees retiring after 1999.

NRG Pension and Postretirement Medical Plans

Components of Net Periodic Benefit Cost

The net annual periodic pension cost related to NRG Energy's plans for the years ended December 31 include the following components:

	Pension Benefits			Other Benefits		
	2002	2001	2000	2002	2001	2000
	(Thousands of dollars)					
Service cost benefits earned	$ 1,478	$2,240	$ —	$1,206	$ 902	$ —
Interest cost on benefit obligation	2,403	2,412	—	1,831	1,402	—
Amortization of prior service cost	—	20	—	(24)	(25)	—
Expected return on plan assets	(1,540)	(937)	—	—	—	—
Recognized actuarial (gain)/loss	—	—	—	5	(56)	—
Net periodic benefit cost	$ 2,341	$3,735	$ —	$3,018	$2,223	$ —

Reconciliation of Funded Status

A comparison of the pension benefit obligation and pension assets at December 31, 2002 and 2001 for all of NRG's plans on a combined basis is as follows:

	Pension Benefits		Other Benefits	
	2002	2001	2002	2001
	(Thousands of dollars)			
Benefit obligation at Jan. 1	$36,832	$ —	$ 24,602	$ 17,734
Service cost	1,478	2,240	1,206	902
Interest cost	2,403	2,412	1,831	1,402
Employee contributions	775	570	—	—
Plan amendments	—	1,118	—	(278)
Actuarial (gain)/loss	(4,804)	(87)	4,101	1,730
Acquisitions (transfers)	(7,848)	31,404	—	3,212
Benefit payments	(1,372)	(515)	(156)	(100)
Foreign currency translation	2,848	(310)	—	—
Benefit obligation at Dec. 31	$ 30,312	$ 36,832	$ 31,584	$ 24,602
Fair value of plan assets at Jan. 1	$ 16,286	$ —	$ —	$ —
Actual return on plan assets	(2,052)	(643)	—	—
Employee contributions	775	—	—	—
Employer contributions	5,816	14	156	100
Benefit payments	(1,372)	(515)	(156)	(100)
Acquisitions	—	17,334	—	—
Foreign currency translation	902	96	—	—
Fair value of plan assets at Dec. 31	$ 20,355	$ 16,286	$ —	$ —
Funded status at Dec. 31 — excess of obligation over assets	$ (9,957)	$ (20,545)	$ (31,584)	$ (24,602)
Unrecognized prior service cost	—	1,098	(229)	(253)
Unrecognized net (gain) loss	(2,294)	208	5,967	1,871
Accrued benefit liability recognized on the consolidated balance sheet at Dec. 31	$(12,251)	$(19,239)	$(25,846)	$(22,984)

The following table presents significant assumptions used:

	Pension Benefits		Other Benefits	
	2002	2001	2002	2001
Weighted-average assumption as of December 31,				
Discount rate	7.00%	7.25- 8.00%	6.75%	7.25%
Expected return on plan assets	7.00	8.00-9.50	—	—
Rate of compensation increase	4.00	4.50-5.00	3.50-4.50	3.50-4.50

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

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 375	$ (315)
Effect on postretirement benefit obligation	3,305	(2,830)

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

Substantially, all eligible employees participate in Xcel Energy's noncontributory, defined benefit pension plan which was formerly sponsored by NSP. NRG Energy's contributions to the Xcel Energy pension plan and postretirement plan totaled $0, $0 and $20,000 in 2002, 2001 and 2000. The balance sheet includes a liability related to the Xcel Energy Pension Plan of $1.7 million and $5.0 million for 2002 and 2001, respectively. The balance sheet also includes a liability related to the Xcel Energy Postretirement Medical Plan of $2.2 million and $2.3 million for 2002 and 2001, respectively. The applicable portion of the total plan benefits and net assets of these plans is not separately identifiable. The net annual periodic credit related to NRG's portion of the Xcel Energy pension plan and postretirement plans totaled $8.9 million, $8.9 million and $1.7 million for 2002, 2001 and 2000, respectively.

Certain NRG employees also participate in Xcel Energy's noncontributory defined benefit supplemental retirement income plan. This plan is for the benefit of certain qualifying executive personnel. Benefits for this unfunded plan are paid out of operating cash flows. The balance sheet includes a liability related to this plan of $3.2 million and $2.6 million as of December 31, 2002 and 2001, respectively.

Defined Contribution Plans

Some NRG Energy employees participated in Xcel Energy's defined contribution 401(K) plan. NRG Energy contributions to the plan were approximately $0.9 million and $0.6 million for the years ended December 31, 2002 and 2001, respectively.

NRG Energy also assumed several contributory, defined contribution employee savings plans as a result of its 2000 and 1999 acquisition activity. These plans comply with Section 401(k) of the Internal Revenue Code and covered substantially all of our employees who were not covered by Xcel Energy's 401(k) Plan. NRG Energy matched specified amounts of employee contributions to the plan. Employer contributions made to these plans were approximately $2.4 million and $1.6 million in 2002 and 2001, respectively.

The Xcel Energy plan (NRG portion) was rolled into the NRG plans for 2002. Employer contributions made to all plans for 2002 were approximately $4.6 million.

NRG Equity Plan

During 1998 and 1999, NRG Energy's employees were eligible to participate in its Equity Plan (the Plan). The Plan granted, to employees, phantom equity units that were intended to simulate Stock options. Grant size was based on the participant's position in NRG Energy and base salary. Equity unit valuations were performed annually by an outside valuation firm. The value of an equity unit was the approximate value per share of NRG Energy's stockholder equity as of the valuation date, less the value of Xcel Energy's (formerly NSP) equity investments. The units were awarded to employees annually at the respective year's calculated share price (grant price). The Plan provided employees with a cash pay out for the unit's appreciation in value over the vesting period. The Plan had a seven year vesting schedule with actual payments beginning after the end of the third year and continuing at 20% each year for the subsequent five years. During 2002, 2001 and 2000, NRG Energy recorded compensation expense of approximately $0, $0, and $6.0 million, respectively, for the Plan.

The Plan included a change of control provision, which allowed all shares to vest if NRG Energy's ownership were to change. Subsequent to the completion of NRG Energy's initial public offering in June 2000, the Plan was converted to a new stock option plan (see Note 20).

Pension and Other Benefits — 2001 Acquisitions

During 2001, NRG Energy acquired several generating assets and assumed benefit obligations for a number of employees associated with those acquisitions. The plans assumption included noncontributory defined benefit pension plans, and contributory post-retirement welfare plans. Of the 2001 acquisitions where these obligations were assumed, approximately 79% percent of such employees are represented by one local union under collective bargaining agreements, which expire on July 1, 2004. Plan liability and expense amounts for these acquisitions are included in the pension and postretirement health care amounts shown above.

Note 17 — Sales to Significant Customers

During 2002, sales to one customer (New York Independent System Operator) accounted for 22.1% of total revenues from majority owned operations in 2002. During 2001, sales to two customers accounted for 33.9% (New York Independent System Operator) and 17.6% (Connecticut Light and Power Co.) of total revenues from majority owned operations in 2001. During 2000, sales to two customers accounted for 26.8% (New York Independent System Operator) and 14.8% (Connecticut Light and Power Co.) of total revenues from majority owned operations in 2000.

Note 18 — *Financial Instruments*

The estimated December 31 fair values of NRG Energy's recorded financial instruments are as follows:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Cash and cash equivalents	$ 381,514	$ 381,514	$ 105,405	$ 105,405
Restricted cash	277,489	277,489	140,323	140,323
Notes receivable, including current portion	990,695	990,695	772,826	772,826
Debt, including current portion	8,211,058	5,829,491	7,318,871	7,210,515

For cash and cash equivalents and restricted cash, the carrying amount approximates fair value because of the short-term maturity of those instruments. The fair value of notes receivable is based on expected future cash flows discounted at market interest rates. The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues.

Derivative Financial Instruments

Foreign Currency Exchange Rates

At December 31, 2002, 2001 and 2000, NRG Energy had various foreign currency exchange instruments with combined notional amounts of $3.0 million, $46.3 million and $8.8 million, respectively. These foreign currency exchange instruments were hedges of expected future cash flows. If the hedges had been terminated at December 31, 2002, 2001 and 2000, NRG Energy would have owed the counter-parties $0.3 million, $2.4 million and $0.7 million, respectively.

Interest Rates

At December 31, 2002, 2001 and 2000, NRG Energy had various interest-rate swap agreements with combined notional amounts of $1.7 billion, $2.4 billion and $530 million, respectively. These contracts are used to manage NRG Energy's exposure to changes in interest rates. If these swaps had been terminated at December 31, 2002, 2001 and 2000, NRG Energy would have owed the counter-parties $41.0 million, $81.5 million and $28.9 million, respectively.

Energy Related Commodities

At December 31, 2002, 2001 and 2000 NRG Energy had various energy related commodities financial instruments with combined notional amounts of $241.8 million, $1.0 billion and $309.0 million, respectively. These financial instruments take the form of fixed price, floating price or indexed sales or purchases, and options, such as puts, calls, basis transactions and swaps. These contracts are used to manage NRG Energy's exposure to commodity price variability in electricity, emission allowances and natural gas, oil and coal used to meet fuel requirements. If these contracts were terminated at December 31, 2002, 2001 and 2000, NRG Energy would have received $58.5 million, $224.1 million and $52.8 million from counter-parties, respectively.

Credit Risk

NRG Energy's counter-parties to its hedging contracts consist principally of financial institutions and major energy companies. NRG Energy actively manages its exposure to counter-party risk. NRG Energy has an established credit policy in place to minimize overall credit risk. Important elements of this policy include ongoing financial reviews of all counter-parties, established credit limits, as well as monitoring, managing and mitigating credit exposure.

Note 19 — Goodwill and Other Intangible Assets

During the first quarter of 2002, NRG Energy adopted SFAS No. 142 — *"Goodwill and Other Intangible Assets"* (SFAS No. 142), which requires new accounting for intangible assets, including goodwill. Intangible assets with finite lives will be amortized over their economic useful lives and periodically reviewed for impairment. Goodwill will no longer be amortized, but will be tested for impairment annually and on an interim basis if an event occurs or a circumstance changes between annual tests that may reduce the fair value of a reporting unit below its carrying value.

NRG Energy had goodwill of $34.2 million at December 31, 2002, which will not be amortized. As of December 31, 2002, NRG Energy performed impairment tests of its goodwill balances. To date, such tests completed have concluded that no write-down of goodwill is necessary primarily because the majority of the goodwill that NRG Energy has recorded relates to its Thermal operations, which have sufficient on going cashflows.

Aggregate amortization expense recognized for the twelve months ended December 31, 2002, 2001 and 2000 was approximately $2.8 million, $4.2 million and $3.1 million, respectively. The annual aggregate amortization expense for each of the five succeeding years is expected to approximate $2.8 million. Intangible assets consisted of the following:

	At December 31, 2002		At December 31, 2001	
Description	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(In thousands)			
Goodwill	$32,958	$ 6,123	$34,583	$ 6,371
Intangibles:				
Service contracts	$65,791	$ 15,987	$65,442	$ 13,682

The following table summarizes the pro forma impact of implementing SFAS No. 142 at January 1, 2000 on net income (loss) for the periods presented.

	For the Year Ended December 31,		
	2002	2001	2000
	(In thousands)		
Reported (loss) income from continuing operations	$ (2,856,216)	$223,802	$149,566
Add back: Goodwill amortization (after-tax)	—	886	761
Adjusted (loss) income from continuing operations	$ (2,856,216)	$224,688	$150,327
Reported net (loss) income	$(3,464,282)	$ 265,204	$182,935
Add back: Goodwill amortization (after-tax)	—	2,919	1,483
Adjusted net (loss) income	$(3,464,282)	$268,123	$184,418

Note 20 — Capital Stock

Sale of Stock

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

In March 2001, NRG Energy completed the sale of 18.4 million shares of common stock for an initial price of $27 per share. The offering was completed with all 18.4 million shares of common stock being sold including the over-allotment shares of 2.4 million. NRG Energy received gross proceeds from the issuance of $496.6 million. Net proceeds from the issuance were $473.4 million after deducting underwriting discounts, commissions and estimated offering expenses. The net proceeds were used in part to reduce amounts outstanding under NRG Energy's short-term bridge credit agreement, which was used to finance in part NRG Energy's acquisition of the LS Power assets. At December 31, 2001, there were approximately 50,939,875 shares of common stock, and 147,605,000 shares of Class A common stock issued and outstanding.

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

Incentive Compensation Plan

In June 2000, NRG Energy adopted a new incentive compensation plan (the New Stock Plan), which was approved by shareholders in June 2001 and which will be administered by a committee appointed by the Board of Directors. The New Stock Plan provides for awards in the form of stock options, stock appreciation rights, restricted stock, performance units, performance shares, or cash based awards as determined by the Board of Directors. All officers, certain other employees, and non-employee directors are eligible to participate in the plan. Nine million shares of common stock are authorized for issuance under the Stock Plan. Initially, only stock option grants will be made to certain officers, independent directors and employees under the plan.

Each new option granted is valued at the fair market value per share at date of grant. The difference between the option price and the market value of the stock at the date of grant, if any, of each option on the date of grant is recorded as compensation expense over a vesting period. Options granted prior to June 2001 vest over a period of five years, with 25% vesting in each of the years two through five and generally expire ten years from the date of grant. Options granted in June 2001 and subsequently, vest over a four year period, with 25% vesting each year and generally expire ten years from the date of grant. The board's independent directors' options vested immediately upon being granted. The average exercise price of vested options at December 31, 2001 and 2000 was $14.39 and $9.51, respectively, all of which were granted in replacement of units previously outstanding under the equity plan. There were no grants in 2002. NRG Energy has recognized approximately $1.9 million and $7.3 million of stock based compensation expense for the periods ended December 31, 2001 and 2000, respectively. In 2002, NRG Energy recognized income due to the net reduction of its compensation expense accrual by approximately $2.3 million for terminated stock options during the period. This amount has been reported as a reduction of compensation expense for the year ended December 31, 2002.

During 2002, the New Stock Plan and all grants under the plan were adopted by the Xcel Energy Incentive Stock Plan. There were no grants to NRG Energy employees under this new plan.

Note 21 — Cash Flow Information

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

	2002	2001	2000
		(Thousands of dollars)	
Interest paid (net of amount capitalized)	$331,679	$ 385,885	$ 248,325
Income taxes paid/(refunds)	$ (17,406)	$ 57,055	$ 20,923
Detail of businesses and assets acquired:			
Current assets (including restricted cash)	$ —	$ 184,874	$ 97,970
Fair value of non-current assets	—	4,779,530	1,896,113
Liabilities assumed, including deferred taxes	—	(2,151,287)	(81,126)
Cash paid net of cash acquired	$ —	$ 2,813,117	$1,912,957

Note 22 — Commitments and Contingencies

Operating Lease Commitments

NRG Energy leases certain of its facilities and equipment under operating leases, some of which include escalation clauses, expiring on various dates through 2023. Rental expense under these operating leases was

$12.6 million, $9.7 million and $2.3 million in 2002, 2001 and 2000, respectively. Future minimum lease commitments under these leases for the years ending after December 31, 2002 are as follows:

	(Thousands of dollars)
2003	$ 11,514
2004	11,220
2005	9,847
2006	9,291
2007	8,739
Thereafter	29,945
Total	$ 80,556

Capital Commitments

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

California

NRG Energy's California generation assets include a 50% interest in the West Coast Power partnership with Dynegy.

In March 2001, the California Power Exchange (PX) filed for bankruptcy under Chapter 11 of the Bankruptcy Code, and in April 2001, the Pacific Gas & Electric Company (PG&E) also filed for bankruptcy under Chapter 11. In September 2001, PG&E filed a proposed plan of reorganization. Under the terms of the proposed plan, which is subject to challenge by interested parties, unsecured creditors such as NRG Energy's California affiliates would receive 60% of the amounts owed upon approval of the plan. The remaining 40% would be paid in negotiable debt with terms from 10 to 30 years. The California PX's ability to repay its debt is dependent on the extent to which it receives payments from PG&E and Southern California Edison Company (SCE). During the fourth quarter of 2002, after assuring the collectibility of its California receivables and other recent related developments, West Coast Power recorded an approximate $117.0 million charge to write-off the remaining amounts owed to it by the California PX and ISO. NRG Energy's share of this charge was approximately $58.5 million (pre-tax).

Connecticut

NRG Energy is impacted by rule/tariff changes that occur in the existing ISOs. On March 1, 2003, ISO-NE implemented its version of Standard Market Design. This change dramatically modifies the New England market structure by incorporating Locational Marginal Pricing (LMP — pricing by location rather than on a New England wide basis). Even though NRG Energy views this change as a significant improvement to the existing market design, NRG Energy still views the market within New England as insufficient to allow for NRG Energy to recover its costs and earn a reasonable return on investment. Consequently, on February 26, 2003, NRG Energy filed and requested a cost of service rate with FERC for most of its Connecticut fleet, requesting a February 27th effective date. NRG Energy remains committed to working with ISO-NE, FERC and other stakeholders to continue to improve the New England market that will hopefully make further reliance on a cost of service rate unnecessary. While NRG Energy has the right to file for such rate treatment, there are no assurances that FERC will grant such rates in the form or amount that NRG Energy petitioned for in its filing.

Contractual Commitments

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

During 1999, NRG Energy acquired the Huntley and Dunkirk generating facilities from Niagara Mohawk Power Corporation (NiMo). In connection with this acquisition, NRG Energy entered into a 4-year agreement with NiMo that requires NRG Energy to provide to NiMo pursuant to a predetermined schedule fixed quantities of energy and capacity at a fixed price.

During 1999, NRG Energy acquired certain generating facilities from Connecticut Light and Power Company (CL&P). NRG also entered into a 4-year standard offer agreement that requires NRG Energy to provide to CL&P a portion of its load requirements through the year 2003 at a substantially fixed rate.

During 2000, NRG Energy acquired the non-nuclear generating assets of Cajun Electric. Upon acquisition of the facilities, NRG Energy entered into various long-term power purchase agreements with the former customers of Cajun Electric, primarily distribution cooperatives and municipalities. These agreements specify that NRG Energy provide these customers with all requirements necessary to satisfy the energy and capacity needs of their retail load.

Also during 2000, NRG Energy acquired the Killingholme generating facilities from National Power plc. In connection with this acquisition, NRG Energy entered into certain agreements to provide the natural gas to operate the facility, which generally sells its power into the spot market. NRG Energy entered into two gas purchase agreements, the first being a 5-year agreement that provides approximately 30% of the generating facilities natural gas requirements and the second agreement being a 10-year agreement that provides approximately 70% of the generating facilities natural gas requirements. NRG Energy also entered into a 5-year fixed price agreement to resell up to 15% of the gas it has contracted for at a slightly higher price. As of December 31, 2002, NRG Energy has entered into an agreement whereby the Killingholme facilities would be turned over to its lenders therefore the assets and liabilities and results of operations have been classified as discontinued operations and held for sale. On January 31, 2003, the Killingholme facilities were sold to its lenders. The obligations under the gas contracts were assumed by the lenders in the sales transaction.

Also during 2000, NRG Energy acquired the Flinders Power operations in South Australia. Upon the closing of the acquisition, NRG Energy assumed a gas purchase and sales agreement relating to the Osborne generating plant with a remaining life of 18-years. These agreements require NRG Energy to purchase a specified quantity of natural gas from a third party supplier at a fixed price for 18-years and resell the natural gas to Osborne at a fixed price for 13-years. The sales price is substantially lower than the purchase price. NRG Energy has recorded the liability associated with this out of the market contract in the amount of approximately $66 million in other long-term obligations and deferred income on its balance sheet. As of December 31, 2002 there remains approximately $73.3 million on NRG Energy's balance sheet. In addition, NRG Energy has entered into a contract for differences agreement which provides for the sale of energy into the South Australian power pool through the year 2002. The agreement provides for a swap of the variable market price to a fixed price.

During 2001, NRG Energy acquired a portfolio of projects located in Delaware, Maryland and Pennsylvania from Conectiv. Upon closing of the acquisition, NRG Energy assumed a power purchase agreement. This agreement, which is not project specific, requires NRG Energy to deliver and Conectiv to purchase 500 MW of electric energy around the clock at a specified price through 2005. The sales price of the contracted electricity was substantially lower than the fair value that the electricity on the merchant market at the date of acquisition. During 2001, NRG Energy recorded the liability associated with the out of market contract on the balance sheet in the amount of approximately $89.4 million. Approximately $45.1 million was recorded in other current liabilities and approximately $44.3 million in other long-term obligations and deferred income. The difference was to be amortized into income over the life of the agreement. In the fourth quarter of 2002, Conectiv terminated this agreement and NRG Energy recorded the unamortized balance into income as revenue, see below for additional information.

Environmental Regulatory Matters

The construction and operation of power projects are subject to stringent environmental and safety protection and land use laws and regulation in the United States. These laws and regulations generally require lengthy and complex processes to obtain licenses, permits and approvals from federal, state and local agencies. If such laws and regulations become more stringent and NRG Energy's facilities are not exempted from coverage, NRG Energy could be required to make extensive modifications to further reduce potential environmental impacts.

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

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

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

In response to liabilities associated with these activities, NRG Energy has established accruals where reasonable estimates of probable liabilities are possible. As of December 31, 2002 and 2001, NRG Energy has established such accruals in the amount of approximately $3.8 million and $5.0 million, respectively, primarily related to its Northeast region facilities (Arthur Kill and Astoria projects). NRG Energy has not used discounting in determining its accrued liabilities for environmental remediation and no claims for possible recovery from third party issuers or other parties related to environmental costs have been recognized in NRG Energy's consolidated financial statements. NRG Energy adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates are adjusted to reflect new information. During the years ended December 31, 2002, 2001 and 2000, NRG Energy recorded expenses of approximately $10.9 million, $15.3 million and $3.4 million related to environmental matters, respectively.

West Coast Region

The Asset Purchase Agreements for the Long Beach, El Segundo, Encina, and San Diego gas turbine generating facilities provide that Southern California Edison and San Diego Gas & Electric retain liability and indemnify NRG Energy for existing soil and groundwater contamination that exceeds remedial thresholds in place at the time of closing. NRG Energy and its business partner conducted Phase I and Phase II Environmental Site Assessments at each of these sites for purposes of identifying such existing contamination and provided the results to the sellers. San Diego Gas & Electric is proceeding to address contamination identified by these studies by undertaking corrective action at the Encina and San Diego gas turbine generating sites. While spills and releases of various substances have occurred at many sites since establishing the historical baseline, all but one has been remediated in accordance with existing laws. An unquantified amount of soil contaminated by lubricating oil that leaked from underground piping at the El Segundo Generating Station has been allowed by the Regional Water Quality Control Board to remain under the foundation of the Unit I powerhouse until the building is demolished.

NRG Energy's affiliates have incurred and anticipates further environmental capital expenditures at the Encina Generating Station to install Selective Catalytic Reduction (SCR) emission control technology on all five generating units. Units 4 & 5 were retrofitted with SCRs during 2002; the additional SCR on Unit 3 was completed in February 2003. SCR emission controls on Units 1 and 2 are expected to be completed in 2003. NRG Energy estimates the cost to retrofit all five units to be approximately $42 million.

Eastern Region

Coal ash is produced as a by-product of coal combustion at the Dunkirk, Huntley, and Somerset Generating Stations. NRG Energy attempts to direct its coal ash to beneficial uses. Even so, significant amounts of ash are landfilled at on and off-site locations. At Dunkirk and Huntley, ash is disposed at landfills owned and operated by NRG Energy. No material liabilities outside the costs associated with closure, post-closure care and monitoring are expected at these facilities. NRG Energy maintains financial assurance to cover costs associated with closure, post-closure care and monitoring activities. In the past, NRG Energy has provided financial assurance via financial test and corporate guarantee. NRG Energy must re-establish financial assurance via an instrument requiring complete collateralization of closure and post-closure-related costs, currently estimated at approximately $5.8 million. NRG Energy is required to provide an alternative instrument to provide such financial assurance on or before April 30, 2003.

NRG must also maintain financial assurance for closing interim status RCRA facilities at the Devon, Middletown, Montville and Norwalk Harbor Generating Stations. Previously, NRG Energy has provided financial assurance via financial test. NRG Energy must re-establish financial assurance via an instrument requiring complete collateralization of closure and post-closure-related costs, currently estimated not to exceed $2.4 million. NRG Energy is required to provide an alternative instrument to provide such financial assurance on or before April 30, 2003.

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

NRG Energy estimates that it will incur total environmental capital expenditures of $53 million during 2003 through 2007 for the facilities in New York, Connecticut and Massachusetts. These expenditures will be primarily related to landfill construction, installation of NO_x controls, installation of the best technology available for minimizing environmental impacts associated with impingement and entrainment of fish and larvae, particulate matter control improvements, spill prevention controls, and undertaking remedial actions. NRG Energy estimates that it will incur in 2003 at all of its plants in the Northeast Region about $8 million in capital expenditures for plant modifications and upgrades required to comply with environmental regulations.

As of December 31, 2002, NRG Energy had recorded an accrual in the amount of $1.6 million to cover penalties associated with historical opacity exceedances.

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

NRG Energy estimates that it will incur capital expenditures of approximately $25 million during the years 2003 through 2007 related to resolving environmental concerns at the Indian River Generating Station. These concerns include the expected closure of the existing ash landfill, the construction of a new ash landfill nearby, the addition of controls to reduce NO_x emissions, fuel yard modifications, and electrostatic precipitator refurbishments to reduce opacity.

Central Region

Liabilities associated with closure, post-closure care and monitoring of the ash ponds owned and operated on site at the Big Cajun II Generating Station are addressed through the use of a trust fund maintained by NRG Energy (one of the instruments allowed by the Louisiana Department of Environmental Quality for providing financial assurance for expenses associated with closure and post-closure care of the ponds). The current value of the trust fund is approximately $4.5 million and NRG Energy is making annual payments to the fund in the amount of about $116,000. See Note 25.

NRG Energy estimates approximately $20 million of capital expenditures will be incurred during the period 2003 and 2007 for the addition of NO_x controls on Units 1 and 2 of Big Cajun II. In addition, NRG Energy estimates that it would incur up to $5 million to reduce particulate matter emissions during start-up of Units 1 and 2 at Big Cajun II.

NYISO Claims

In November 2002, the NYISO notified NRG Energy of claims related to New York City mitigation adjustments, general NYISO billing adjustments and other miscellaneous charges related to sales between November 2000 and October 2002. NRG Energy contests both the validity and calculation of the claims and is currently negotiating with the NYISO over the ultimate disposition. Accordingly, NRG Energy reduced its revenues by $21.7 million and recorded a corresponding reserve for the receivable.

Conectiv Agreement Termination

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

Legal Issues

California Wholesale Electricity Litigation and Related Investigations

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

This action was filed in state court on March 11, 2002. It alleges that the defendants violated California Business & Professions Code § 17200 by selling ancillary services to the California ISO, and subsequently selling the same capacity into the spot market. The Attorney General seeks injunctive relief as well as restitution, disgorgement and civil penalties.

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

The Attorney General filed motions to remand, which the defendants opposed in July of 2002. In an Order filed in early September 2002, Judge Walker denied the remand motions. The Attorney General has appealed that decision to the United States Court of Appeal for the Ninth Circuit, and the appeal remains pending. The Attorney General also sought a stay of proceedings in the district court pending the appeal, and this request was also denied. A “Notice of Bankruptcy Filing” respecting NRG Energy was filed in the Ninth Circuit and in the District Court in mid-December 2002. The Attorney General filed a paper asserting that the “police power” exception to the automatic stay is applicable here. Judge Walker agreed with the Attorney General on this issue. In a lengthy opinion filed March 25, 2003, Judge Walker dismissed the Attorney General’s action against NRG and Dynegy with prejudice, finding it was barred by the filed rate doctrine and preempted by federal law. The Attorney General has announced it will appeal the dismissal. NRG Energy is unable at this time to accurately estimate the damages sought by the Attorney General against NRG Energy and its affiliates, or predict the outcome of the case.

A “Notice of Bankruptcy Filing” respecting NRG Energy was filed in the Ninth Circuit and in the District Court in mid-December, 2002. The Attorney General filed a paper asserting that the “police power” exception to the automatic stay is applicable here.

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

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

The action was transferred from Los Angeles to the United States District Court in San Diego and was made a part of the Multi-District Litigation proceeding described below. All defendants filed motions to dismiss and to strike in the fall of 2002. In an Order dated January 6, 2003, the Honorable Robert Whaley, a federal judge from Spokane sitting in the United States District Court in San Diego, pursuant to the Order of the MDL Panel, granted the motions to dismiss on the grounds of federal preemption and filed-rate doctrine. The plaintiffs have filed a notice of appeal.

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

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

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

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

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

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

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

These cases were all filed in late 2000 and 2001 in various state courts throughout California. They allege unfair competition, market manipulation, and price fixing. All the cases were removed to the appropriate United States District Courts, and were thereafter made the subject of a petition to the Multi-District Litigation Panel (Case No. MDL 1405). The cases were ultimately assigned to Judge Whaley. Judge Whaley entered an order in 2001 remanding the cases to state court, and thereafter the cases were coordinated pursuant to state court coordination proceedings before a single judge in San Diego Superior Court. The defendants filed motions to dismiss and to strike under the filed-rate and federal preemption theories, and the plaintiffs challenged the district court's jurisdiction and sought to have the cases remanded to state court. In December 2002, Judge Whaley issued an opinion finding that federal jurisdiction was absent in the district court, and remanding the cases to state court. Duke Energy and Reliant Energy have filed a notice of appeal with the Ninth Circuit, and also sought a stay of the remand pending appeal. The stay request was denied by Judge Whaley. On February 20, 2003, however, the Ninth Circuit stayed the remand order and accepted jurisdiction to hear the appeal of Reliant Energy and Duke Energy on the remand order. The Company anticipates that filed-rate/federal preemption pleading challenges will once again be filed once the remand appeal is decided. A "Notice of Bankruptcy Filing" respecting NRG Energy has also been filed in this action, providing notice of the involuntary petition.

"Northern California" cases against various market participants, not including NRG Energy (part of MDL 1405). These include the *Millar, Pastorino, RDJ Farms, Century Theatres, El Super Burrito, Leo's, J&M Karsant,* and the *Bronco Don* cases. NRG Energy, Inc. was not named in any of these cases, but in virtually all of them, either West Coast Power or one or more of the operating LLC's with which the Company is indirectly affiliated is named as a defendant. These cases all allege violation of Business & Professions Code § 17200, and are similar to the various allegations made by the Attorney General. Dynegy is named as a defendant in all these actions, and Dynegy's outside counsel is representing both Dynegy and the West Coast Power entities in each of these cases.

"Pacific Northwest" cases: *Symonds v. Dynegy Power Marketing et al.,* United States District Court, Western District of Washington, Case No. CV02-2552; *Lodewick v. Dynegy Power Marketing et al.,* Oregon Circuit Court Case No. 0212-12771. These cases were just recently asserted and contain similar claims to those found in the California cases described above. There has been little activity in either case.

Bustamante v. McGraw-Hill Companies Inc., et al., *No. BC 285598,* California Superior Court, Los Angeles County

This putative class action lawsuit was filed on November 20, 2002. In addition to naming WCP-related entities as defendants, numerous industry participants are named in this lawsuit that are unrelated to WCP or NRG Energy. The Complaint generally alleges that the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades. Named defendants in the suit are the LLCs established by WCP for each of its four plants: El Segundo Power, LLC; Long Beach Generation, LLC; Cabrillo Power I LLC; and Cabrillo Power II LLC. NRG Energy is not named as a defendant. The complaint seeks restitution and disgorgement of "ill-gotten gains", civil fines, compensatory and punitive damages, attorneys' fees, and declaratory and injunctive relief.

Dynegy has agreed with NRG Energy that it will indemnify and hold harmless the named defendants in the Bustamante lawsuit, as well as NRG Energy, from any civil fines, compensatory damages, punitive damages, costs, and fees that may be entered pursuant to either a final judgment or a settlement of claims. Dynegy has also agreed that it will pay all costs and attorneys' fees associated with the defense of the named defendants in the Bustamante lawsuit, as well as any defense costs for NRG Energy.

Investigations

FERC — California Market Manipulation

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

In August, 2002, the 9th U.S. Circuit Court of Appeals granted a request by the Electricity Oversight Board, the California Public Utilities Commission, and others, to seek out and introduce to FERC additional evidence of market manipulation by wholesale sellers. This decision resulted in FERC ordering an additional 100 days of discovery in the refund proceeding, and also allowing the relevant time period for potential refund liability to extend back an additional nine months, to January 1, 2000.

On December 12, 2002, FERC Administrative Law Judge Birchman issued a Certification of Proposed Findings on California Refund Liability in Docket No. EL00-95-045 *et al.*, which determined the method for the mitigated energy market clearing price during each hour of the refund period. On March 26, 2003, FERC issued an Order on Proposed Findings on Refund Liability in Docket No. EL00-95-045 (“Refund Order”), adopting, in part, and modifying, in part, the Proposed Findings issued by Judge Birchman on December 12, 2002. In the Refund Order, FERC adopted the refund methodology in the Staff Final Report on Price Manipulation in Western Markets issued contemporaneously with the Refund Order in Docket No. PA02-2-000. This refund calculation methodology makes certain changes to Judge Birchman’s methodology, because of FERC Staff’s findings of manipulation in gas index prices. This could materially increase the estimated refund liability. The Refund Order also directs generators that want to recover any fuel costs above the mitigated market clearing price during the refund period to submit cost information justifying such recovery within forty (40) days of the issuance of the Refund Order. FERC announced in the Refund Order that it expects that refunds will be paid by suppliers by the end of summer 2003.

California Attorney General

In addition to the litigation it has undertaken described above, the California Attorney General has undertaken an investigation entitled *In the Matter of the Investigation of Possibly Unlawful, Unfair, or Anti-Competitive Behavior Affecting Electricity Prices in California.* In this connection, the Attorney General has issued subpoenas to Dynegy, served interrogatories on Dynegy and NRG Energy, and informally requested documents and interviews from Dynegy and Dynegy employees as well as NRG Energy and NRG Energy employees. NRG Energy responded to the interrogatories last summer, with the final set of responses being served on September 3, 2002. NRG Energy has also produced a large volume of documentation relating to the West Coast Power plants. In addition, three NRG Energy employees in California have sat for informal interviews with representatives of the Attorney General’s office. Dynegy employees have also been interviewed. The Attorney General’s office has requested an additional interview with NRG Energy’s plant manager of El Segundo.

Although any evaluation of the likelihood of an unfavorable outcome or an estimate of the amount or range of potential loss in the above-referenced private actions and various investigations cannot be made at this time, NRG Energy notes that the Gordon complaint alleges that the defendants, collectively, overcharged California ratepayers during 2000 by $4.0 billion. NRG Energy knows of no evidence implicating NRG Energy in plaintiffs’ allegations of collusion. NRG Energy cannot predict the outcome of these cases and investigations at this time.

The Minnesota Involuntary Bankruptcy Case

On November 22, 2002, a petition commencing an involuntary bankruptcy proceeding pursuant to Chapter 11 of the Bankruptcy Code was filed by five of NRG Energy’s former officers, Brian Bird, Leonard Bluhm, Craig Mataczynski, John Noer and David Peterson in the United States Bankruptcy Court for the District of Minnesota. Roy Hewitt and James Bender subsequently joined in the petition. NRG Energy has subsequently filed an answer and a motion to dismiss the Involuntary Case. The court will consider the motion to dismiss. In their petition filed with the Minnesota Bankruptcy Court, the petitioners sought recovery of severance and other benefits in an aggregate amount of $27.7 million.

Since the commencement of the Minnesota involuntary case, NRG Energy and its counsel have been involved in extensive negotiations with the petitioners and their counsel. As a result of these negotiations, NRG Energy and the petitioners reached an agreement and compromise regarding their respective claims against each other. On February 17, 2003, the Settlement Agreement was executed by the Petitioners and NRG Energy, pursuant to which NRG Energy agreed to pay the Petitioners an aggregate settlement in the amount of $12.2 million.

On February 28, 2003, Stone & Webster, Inc. and Shaw Constructors, Inc. filed a Joinder in Involuntary Petition alleging that they hold unsecured, non-contingent claims against NRG Energy, in a joint amount of $100 million. On March 20, 2003, Connecticut Light & Power Company filed an opposition to the NRG Energy motion to dismiss the Involuntary Case.

The Minnesota Bankruptcy Court has discretion in reviewing and ruling on the motion to dismiss and the review and approval of the settlement agreement. There is a risk that the Minnesota Bankruptcy Court may, among other things, reject the settlement agreement or enter an order for relief under Chapter 11 of the Bankruptcy Code, thus commencing a Chapter 11 case for NRG Energy.

Fortistar Capital Inc. v. NRG Energy, Inc., Hennepin County District Court.

On July 12, 1999, Fortistar Capital Inc. sued NRG Energy in Minnesota state court. The complaint sought injunctive relief and damages of over $50 million resulting from NRG Energy's alleged breach of a letter agreement with Fortistar relating to the Oswego power plant. NRG Energy asserted counterclaims. After considerable litigation, the parties entered into a conditional, confidential settlement agreement, which was subject to necessary board and lender approvals. NRG Energy was unable to obtain necessary approvals. Fortistar has moved the court to enforce the settlement, seeking damages in excess of $35 million plus interest and attorneys' fees. NRG Energy is opposing Fortistar's motion on the grounds that conditions to contract performance have not been satisfied. No decision has been made on the pending motion, and NRG Energy cannot predict the outcome of this dispute.

Fortistar RICO Claims/ Indemnity Requests

On Feb. 26, 2003, Fortistar Capital, Inc. and Fortistar Methane, LLC filed a lawsuit in the Federal District Court for the Northern District of New York against Xcel Energy and five present or former NRG Energy or NEO officers and employees. NRG Energy is a wholly owned subsidiary of Xcel Energy, and NEO is a wholly owned subsidiary of NRG Energy. In the lawsuit, Fortistar claims that the defendants violated the Racketeer Influenced and Corrupt Organizations Act ("RICO") and committed fraud by engaging in a pattern of negotiating and executing agreements "they intended not to comply with" and "made false statements later to conceal their fraudulent promises." The plaintiffs allege damages of some $350 million and also assert entitlement to a trebling of these damages under the provisions of the RICO Act. The present and former NRG Energy and NEO officers and employees have requested indemnity from NRG Energy, which requests NRG Energy is now examining. NRG Energy cannot at this time estimate the likelihood of an unfavorable outcome to the defendants in this lawsuit.

***NEO Corporation, a Minnesota Corporation on Behalf of Itself and on Behalf of Minnesota Methane, LLC, a Delaware Limited Liability Company v. Fortistar Methane, LLC,* a Delaware Limited Liability Company, Hennepin County District Court**

NEO Corporation, a wholly owned subsidiary of NRG Energy, brought this lawsuit in January of 2001. NEO has asserted claims for breach of contract, breach of the covenant of good faith and fair dealing, fraudulent misrepresentations and omissions, defamation, business disparagement and derivative claims. Fortistar Methane, LLC denied NEO's claims and counterclaimed alleging breach of contract, fraud, negligent misrepresentation and breach of warranty. NEO has denied Fortistar Methane's claims and intends to pursue its claims. Discovery has not been conducted. The parties entered into a conditional, confidential settlement of this matter and the Fortistar Capital action, described above. The agreement, however, was subject to necessary board and lender approvals. NEO was unable to obtain necessary approvals. Fortistar Methane has moved to enforce the settlement, seeking damages against NRG Energy in excess of $35 million plus interest and attorneys' fees. NRG Energy and NEO are opposing Fortistar's motion on the grounds that conditions to contract performance were not met. No decision has been rendered on the pending motion. NRG Energy cannot predict the likelihood of an unfavorable outcome.

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

This matter involves a claim by Connecticut Light & Power Company for recovery of amounts it claims is owing for congestion charges under the terms of a Standard Offer Services contract between the parties, dated October 29, 1999. CL&P has served and filed its motion for summary judgment and to which NRG Power Marketing filed a response in March 2003. CL&P has offset approximately $30 million from amounts owed to NRG Power Marketing, claiming that it has the right to offset those amounts under the contract. NRG Power Marketing has counterclaimed seeking to recover those amounts, among other things arguing that CL&P has no rights under the contract to offset them. NRG Power Marketing cannot estimate at this time the likelihood of an unfavorable outcome in this matter, or the overall exposure for congestion charges for the full term of the contract.

***The State of New York and Erin M. Crotty, as Commissioner of the New York State Department of Environmental Conservation v. Niagara Mohawk Power Corporation et al.,* United States District Court for the Western District of New York, Civil Action No. 02-CV-002S**

In January, 2002, NRG Energy and Niagara Mohawk Power Corporation (“NiMo”) were sued by the New York Department of Environmental Conservation in federal court in New York. The complaint asserts that projects undertaken at NRG Energy’s Huntley and Dunkirk plants by NiMo, the former owner of the facilities, should have been permitted pursuant to the Clean Air Act and that the failure to do so violated federal and state laws. In July, 2002, NRG Energy filed a motion to dismiss. The motion is still pending before the judge and there has been no further action taken in connection with the case. On March 27, 2003 the court dismissed the complaint against NRG Energy without prejudice. It is possible the State will appeal this dismissal to the Second Circuit Court of Appeals or could re-file a case against NRG Energy. If the case ultimately is litigated to a judgment and there is an unfavorable outcome that could not be addressed through use of compliant fuels and/or a plant wide applicability limit, NRG Energy has estimated that the total investment that would be required to install pollution control devices could be as high as $300 million over a ten to twelve-year period, and NRG Energy maybe responsible for payment of certain penalties and fines.

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

NRG Energy has asserted that NiMo is obligated to indemnify it for any related compliance costs associated with resolution of the enforcement action. NiMo has filed suit in state court in New York seeking a declaratory judgment with respect to its obligations to indemnify NRG Energy under the asset sales agreement.

Huntley Power LLC, Dunkirk Power LLC and Oswego Harbor Power LLC

All three of these facilities have been issued Notices of Violation with respect to opacity exceedances. NRG Energy has been engaged in consent order negotiations with the New York State Department of Environmental Conservation relative to opacity issues affecting all three facilities periodically since 1999. One proposed consent order was forwarded by DEC under cover of a letter dated January 22, 2002, which makes reference to 7,890 violations at the three facilities and contains a proposed payable penalty for such violations of $900,000. On February 5, 2003, DEC sent to us a proposed Schedule of Compliance and asserted that it is to be used in conjunction with newly-drafted consent orders. NRG Energy has not yet received the consent orders although NRG Energy has been told by DEC that DEC is now seeking a penalty in excess of that cited in its January 22, 2002 letter. NRG Energy expects to continue negotiations with DEC regarding the proposed consent orders, including the Schedule of Compliance and the penalty amount. NRG Energy cannot predict whether those discussions with the DEC will result in a settlement and, if they do, what sanctions will be imposed. In the event that the consent order negotiations are unsuccessful, NRG Energy does not know what relief DEC will seek through an enforcement action and what the result of such action will be.

***Niagara Mohawk Power Corporation v. Dunkirk Power LLC, et al.,* Supreme Court, Erie County, Index No. 1-2000-8681**

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

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

On October 8, 2002, a Stipulation and Order was filed in the Erie County Clerk's Office staying this action pending submission of some or all of the disputes in the action to the FERC. NRG Energy cannot make an evaluation of the likelihood of an unfavorable outcome. The cumulative potential loss could exceed $35 million.

***Pointe Coupee Parish Police Jury and Louisiana Generating, LLC v. United States Environmental Protection Agency and Christine Todd Whitman, Administrator,* Adversary Proceeding No. 02-61021 on the Docket of the United States Court of Appeals for the Fifth Circuit**

On December 2, 2002, a Petition for Review was filed to appeal the United States Environmental Protection Agency's approval of the Louisiana Department of Environmental Quality's ("DEQ") revisions to the Baton Rouge State Implementation Plan ("SIP"). Pointe Coupee and NRG Energy's subsidiary, Louisiana Generating, object to the approval of SIP Section *4.2.1. Permitting NO(x)* Sources that purports to require DEQ to obtain offsets of major increases in emissions of nitrogen oxides (NO(x)) associated with major modifications of existing facilities or construction of new facilities both in the Baton Rouge Ozone Nonattainment Area and in four adjoining attainment parishes referred to as the Region of Influence, including Pointe Coupee Parish. The plaintiffs' challenge is based on DEQ's failure to comply with Administrative Procedures Act requirements related to rulemaking and EPA's regulations which prohibit EPA from approving a SIP not prepared in accordance with state law. The court granted a sixty (60) day stay of this proceeding on February 25, 2003 to allow the parties to conduct settlement discussions. At this time, NRG Energy is unable to predict the eventual outcome of this matter or the potential loss contingencies, if any, to which the Company may be subject.

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

During 2000, DEQ issued a Part 70 Air Permit modification to Louisiana Generating to construct and operate two 240 MW natural gas-fired turbines. The Part 70 Air Permit set emissions limits for the criteria air pollutants, including Nox, based on the application of Best Available Control Technology ("BACT"). The

BACT limitation for NO(x) was based on the guarantees of the manufacturer, Siemens-Westinghouse. Louisiana Generating sought an interim emissions limit to allow Siemens-Westinghouse time to install additional control equipment. To establish the interim limit, DEQ issued a Compliance Order and Notice of Potential Penalty, No. AE-CN-02-0022, on September 8, 2002, which is, in part, subject to the referenced administrative hearing. DEQ alleged that Louisiana Generating did not meet its NO(x) emissions limit on certain days, did not conduct all opacity monitoring and did not complete all record keeping and certification requirements. Louisiana Generating intends to vigorously defend certain claims and any future penalty assessment, while also seeking an amendment of its limit for NO(x). An initial status conference has been held with the Administrative Law Judge and quarterly reports will be submitted to describe progress, including settlement and amendment of the limit. In addition, NRG Energy may assert breach of warranty claims against the manufacturer. With respect to the administrative action described above, at this time NRG Energy is unable to predict the eventual outcome of this matter or the potential loss contingencies, if any, to which the Company may be subject.

NRG Sterlington Power, LLC

During 2002, NRG Sterlington conducted a review of the Sterlington Power Facility's Part 70 Air Permit obtained by the facility's former owner and operator, Koch Power, Inc. Koch had outlined a plan to install eight 25 megawatt (MW) turbines to reach a 200 MW limit in the permit. Due to the inability of several units to reach their nameplate capacity, Koch determined that it would need additional units to reach the electric output target. In August 2000, NRG Sterlington acquired the remaining interests in the facility not originally held on a passive basis and sought the transfer of the Part 70 Air Permit along with a modification to incorporate two 17.5 MW turbines installed by Koch and to increase the total number of turbines to ten. The permit modification was issued February 13, 2002. During further review, NRG Sterlington determined that a ninth unit had been installed prior to issuance of the permit modification. In keeping with its environmental policy, it disclosed this matter to DEQ during April, 2002. Additional information was provided during July 2002. As DEQ has not acted to date to institute an enforcement proceeding, NRG Energy suspects that it may not. However, as it is not time barred from doing so, NRG Energy is unable at this time to predict the eventual outcome or potential loss contingencies, if any, to which the Company may be subject.

FERC Investigation of Saguaro Power Company

On February 24, 2003, FERC initiated an investigation into whether Saguaro Power Company satisfied or currently satisfies the statutory and regulatory requirements for a qualifying facility under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA provides special benefits for qualifying facilities regarding their rights to sell the electrical output of generation projects to electric utilities and exempts qualifying facilities from certain state and federal regulation. NRG Energy's wholly-owned subsidiary, Eastern Sierra Power Company, owns a 49% general partnership interest and a 1% limited partnership interest in Saguaro. The FERC Order initiating the investigation notes that certain financing arrangements between Enron North America and Boulder Power LLC, an indirect owner of a 14% general partnership interest and a 1% limited partnership interest in Saguaro, may have caused Saguaro not to meet the limitations on electric utility ownership applicable to qualifying facilities under PURPA and FERC regulations. At this time, NRG Energy is unable to predict the likelihood of an unfavorable outcome of this matter or the remedies that the FERC would impose in the event it found that Sagauro did not or does not satisfy the requirements for a qualifying facility.

Stone & Webster, Inc. and Shaw Constructors, Inc. v. NRG Energy, Inc. et al.

On October 17, 2002, Stone & Webster, Inc. and Shaw Constructors, Inc. filed a lawsuit against NRG Energy, Xcel Energy, Inc., NRG Granite Acquisition LLC, Granite Power Partners II LP and two of Xcel Energy's executives relating to the construction of a power plant in Pike County, Mississippi. Plaintiffs generally allege that they were not paid for work performed to construct the power plant, and have sued the parent entities of the company with which they contracted to build the plant in order to recover amounts allegedly owing. Plaintiffs assert claims for breach of fiduciary duty, piercing the corporate veil, breach of contract, tortious interference with contract, enforcement of the NRG Energy guaranty, detrimental reliance, negligent or intentional misrepresentation, conspiracy, and aiding and abetting. On December 23, 2002, NRG Energy moved to dismiss the complaint in its entirety for failure to state a claim upon which relief can be granted. NRG Energy is currently awaiting plaintiffs' response to the motion. No trial date has yet been set in this matter and NRG Energy cannot presently predict the outcome of the dispute.

The Mississippi Involuntary Case

On October 17, 2002, a petition commencing an involuntary bankruptcy proceeding pursuant to Chapter 7 of the Bankruptcy Code was filed against LSP-Pike Energy, LLC, a subsidiary of NRG Energy, by Stone & Webster, Inc. and Shaw Constructors, Inc. — the joining petitioners in the Minnesota involuntary case described above — in the United States Bankruptcy Court for the Southern District of Mississippi. In their petition filed with the Mississippi Bankruptcy Court, the joining petitioners sought recovery of allegedly unpaid contractual construction-related obligations in an aggregate amount of $73,833,328, which amount LSP-Pike Energy, LLC has disputed. LSP-Pike Energy, LLC filed an answer to the petition in the Mississippi involuntary case and served various interrogatory and deposition discovery requests on the joining petitioners. The Mississippi Bankruptcy Court has not entered any order for relief in the Mississippi involuntary case.

FirstEnergy Arbitration Claim

On November 29, 2001, The Cleveland Electric Illuminating Company, The Toledo Edison Company and FirstEnergy Ventures ("Sellers") entered into Purchase and Sale Agreements with NRG Able Acquisition LLC, which were guaranteed by NRG (collectively, "Purchasers"), for the purchase of certain power plants for approximately $1.5 billion. On August 8, 2002, Sellers terminated the agreements and asserted that Purchasers were liable for anticipatory breach of the Purchase and Sale Agreements on the grounds that they could not finance the purchases. On August 8, 2002, Purchasers provided notice that they disagreed with Sellers' assertion. After Sellers filed a motion seeking a waiver of the automatic stay of Section 362(a) of the Bankruptcy Code, on February 21, 2003, Sellers, NRG Energy, and NRG Northern Ohio Generating LLC, f/k/a/ NRG Able, stipulated to the United States Bankruptcy Court, District of Minnesota, that they would agree to a waiver of the automatic stay, thereby allowing Sellers to commence arbitration against Purchasers regarding their dispute. The collection of any award, however, would remain fully subject to NRG Energy's automatic stay. The Bankruptcy Court approved the stipulation. On February 26, 2002, Sellers provided notice of their intent to commence arbitration proceedings against Purchasers. Sellers have yet to quantify their damage claim, though Sellers have stated publicly that they will seek to recover several hundred million dollars. NRG Energy cannot presently predict the outcome of this dispute. See Note 29 for additional discussion regarding the FirstEnergy settlement completed in 2003.

General Electric Company and Siemens Westinghouse Turbine Purchase Disputes

NRG Energy and/or its affiliates have entered into several turbine purchase agreements with affiliates of General Electric Company and Siemens Westinghouse Power Corporation. GE and Siemens have notified NRG Energy that it is in default under certain of those contracts, terminated such contracts, and demanded that NRG Energy pay the termination fees set forth in such contracts. GE's claim amounts to $120 million and Siemens' approximately $45 million in cumulative termination charges. NRG Energy has recorded a liability for the amounts they believe they owe under the contracts and termination provisions. NRG Energy cannot estimate the likelihood of unfavorable outcomes in these disputes.

Itiquira Energetica, S.A.

NRG Energy's indirectly controlled Brazilian project company, Itiquira Energetica S.A., the owner of a 156MW hydro project in Brazil, is currently in arbitration with the former EPC contractor for the project, Inepar Industria e Construcoes (Inepar). The dispute was commenced by Itiquira in September, 2002 and pertains to certain matters arising under the former EPC contract. Itiquira principally asserts that Inepar breached the contract and caused damages to Itiquira by (i) failing to meet milestones for substantial completion; (ii) failing to provide adequate resources to meet such milestones; (iii) failing to pay subcontractors amounts due; and (iv) being insolvent. Itiquira's arbitration claim is for approximately US$40 million. Inepar has asserted in the arbitration that Itiquira breached the contact and caused damages to Inepar by failing to recognize events of force majeure as grounds for excused delay and extensions of scope of services and material under the contract. Inepar's damage claim is for approximately US$10 million. On November 12, 2002, Inepar submitted its affirmative statement of claim, and Itiquira submitted its response and statement of counterclaims on December 14, 2002. Inepar replied to Itiquira's response and counterclaims on January 14, 2003. Itiquira is to submit its reply to Inepar's January 14 filing on March 14, 2003, and a hearing was held on March 21, 2003. NRG Energy cannot estimate the likelihood of an unfavorable outcome in this dispute.

NRG Energy Credit Defaults

NRG Energy and various of its subsidiaries are in default under various of their credit facilities, financial instruments, construction agreements and other contracts, which have given rise to liens, claims and contingencies against them and may in the future give rise to additional liens, claims and contingencies against them. In addition, NRG Energy and various of its subsidiaries have entered into various guarantees, equity contribution agreements, and other financial support agreements with respect to the obligations of their affiliates, which have given rise to liens, claims and contingencies against them and may in the future give rise to additional liens, claims and contingencies against the party or parties providing the financial support. NRG Energy cannot predict the outcome or financial impact of these matters.

Note 23 — Segment Reporting

NRG Energy conducts its business within six segments: Independent Power Generation in North America, Independent Power Generation outside North America (Europe, Asia Pacific and Other Americas regions), Alternative Energy and Thermal projects. NRG Energy's Revenues from majority owned operations attributable to Europe and Asia Pacific primarily relate to operations in the United Kingdom and Australia, respectively. These segments are distinct components with separate operating results and management structures in place. The "Other" category includes operations that do not meet the threshold for separate disclosure and corporate charges (primarily interest expense) that have not been allocated to the operating segments.

	Power Generation			
	North America	Europe	Asia Pacific	Other Americas
	(Thousands of dollars)			
2002				
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 1,533,461	$ 107,466	$ 172,372	$ 58,185
Equity in earnings of unconsolidated affiliates	42,923	25,434	23,150	713
Total operating revenues and equity earnings	1,576,384	132,900	195,522	58,898
Depreciation and amortization	176,234	165	14,968	13,604
Write down and losses on equity method investments	42,989	—	139,859	—
Special charges	2,096,316	50,188	1,546	3,525
Operating (loss) income	(1,807,753)	(4,938)	(123,842)	11,341
Other income (expense), net	803	10,084	(2,069)	1,398
Interest expense	(259,106)	(703)	(4,398)	(7,884)
Income before income taxes	(2,067,811)	4,443	(130,309)	5,320
Income tax expense	15,424	15,017	(700)	1,808
Net Income (Loss) from continuing operations	(2,083,235)	(10,574)	(129,609)	3,512
Net Income (Loss) from discontinued operations	(21,792)	(448,411)	(101,312)	(9,062)
Net Income (Loss)	(2,105,027)	(458,985)	(230,921)	(5,550)
Balance Sheet				
Equity investments in affiliates	514,062	149,214	130,422	30,243
Total assets	7,525,820	1,261,742	688,926	416,313

	Alternative Energy	Thermal	Other	Total
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 100,352	$ 111,809	$ 4,787	$ 2,088,432
Equity in earnings of unconsolidated affiliates	(24,036)	—	812	68,996
Total operating revenues and equity earnings	76,316	111,809	5,599	2,157,428
Depreciation and amortization	18,295	10,611	7,644	241,521
Write down and losses on equity method investments	15,542	—	2,082	200,472
Special charges	27,893	31	448,267	2,627,766
Operating (loss) Income	(52,281)	26,688	(587,039)	(2,537,824)
Other income (expense), net	1,503	(193)	(7,294)	4,232
Interest expense	(3,668)	(7,827)	(200,984)	(484,570)
Income before income taxes	(54,446)	18,668	(795,317)	(3,019,452)
Income tax expense	(16,701)	7,194	(185,278)	(163,236)
Net Income (Loss) from continuing operations	(37,745)	11,474	(610,039)	(2,856,216)
Net Income (Loss) from discontinued operations	(27,489)	—	—	(608,066)
Net Income (Loss)	(65,234)	11,474	(610,039)	(3,464,282)
Balance Sheet				
Equity investments in affiliates	28,673	—	31,649	884,263
Total assets	192,704	283,438	523,840	10,892,783

	Power Generation			
	North America	Europe	Asia Pacific	Other Americas
	(Thousands of dollars)			
2001				
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$1,673,924	$ 72,540	$ 214,817	$ 28,227
Equity in earnings of unconsolidated affiliates	181,335	41,688	13,227	3,886
Total operating revenues and equity earnings	1,855,259	114,228	228,044	32,113
Depreciation and amortization	112,392	216	14,703	5,235
Operating Income (Loss)	631,443	47,905	22,735	10,812
Other income (expense), net	6,827	3,731	1,637	2,010
Interest expense	(163,839)	(1,199)	(7,177)	(2,952)
Income before income taxes	472,629	50,438	17,195	9,824
Income tax expense	73,382	7,956	5,566	3,244
Net Income (Loss) from continuing operations	399,247	42,482	11,629	6,580
Net Income (Loss) from discontinued operations	8,702	39,766	(843)	647
Net Income (Loss)	407,949	82,248	10,786	7,227
Balance Sheet				
Equity investments in affiliates	554,846	119,148	263,236	35,081
Total assets	8,241,928	1,803,255	787,680	448,871

	Alternative Energy	Thermal	Other	Total
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 74,849	$ 108,319	$ 18,476	$ 2,191,152
Equity in earnings of unconsolidated affiliates	(26,637)	—	(3,467)	210,032
Total operating revenues and equity earnings	48,212	108,319	15,009	2,401,184
Depreciation and amortization	16,004	11,224	3,240	163,014
Operating Income (Loss)	(16,699)	18,665	(81,946)	632,915
Other income (expense), net	2,758	69	2,688	19,720
Interest expense	(1,724)	(5,555)	(205,242)	(387,688)
Income before income taxes	(15,665)	13,179	(284,500)	263,100
Income tax expense	(47,159)	5,436	(9,127)	39,298
Net Income (Loss) from continuing operations	31,494	7,743	(275,373)	223,802
Net Income (Loss) from discontinued operations	855	—	(7,725)	41,402
Net Income (Loss)	32,349	7,743	(283,098)	265,204
Balance Sheet				
Equity investments in affiliates	34,969	—	30,915	1,038,195
Total assets	201,795	256,791	1,175,940	12,916,260

	Power Generation			
	North America	Europe	Asia Pacific	Other Americas
	(Thousands of dollars)			
2000				
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$1,448,305	$ 1,337	$94,772	$ 291
Equity in earnings of unconsolidated affiliates	122,900	9,698	3,831	4,729
Total operating revenues and equity earnings	1,571,205	11,035	98,603	5,020
Depreciation and amortization	71,797	58	5,913	—
Operating Income	560,096	7,122	13,672	4,970
Other income (expense), net	4,715	(1,479)	1,602	1
Interest expense	(124,126)	(884)	(3,393)	66
Income before income taxes	439,845	4,759	11,881	5,037
Income tax expense	65,341	4,617	(4,066)	40
Net Income (Loss) from continuing operations	374,504	142	15,947	4,997
Net Income (Loss) from discontinued operations	31,173	17,521	—	—
Net Income (Loss)	405,677	17,663	15,947	4,997

	Alternative Energy	Thermal	Other	Total
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	33,143	84,901	6,782	1,669,531
Equity in earnings of unconsolidated affiliates	(19,637)	—	17,843	139,364
Total operating revenues and equity earnings	13,506	84,901	24,625	1,808,895
Depreciation and amortization	4,097	10,055	2,158	94,078
Operating Income (Loss)	(24,579)	16,702	(85,336)	492,647
Other income (expense), net	1,440	440	(923)	5,796
Interest expense	(2,143)	(6,288)	(112,909)	(249,677)
Income before income taxes	(25,282)	10,854	(199,168)	247,926
Income tax expense	(36,167)	4,379	64,216	98,360
Net Income (Loss) from continuing operations	10,885	6,475	(263,384)	149,566
Net Income (Loss) from discontinued operations	1,357	—	(16,682)	33,369
Net Income (Loss)	12,242	6,475	(280,066)	182,935

Note 24 — Jointly Owned Plants

On March 31, 2000, NRG Energy acquired a 58% interest in the Big Cajun II, Unit 3 generation plant. Entergy Gulf States owns the remaining 42%. Big Cajun II, Unit 3 is operated and maintained by Louisiana Generating pursuant to a joint ownership participation and operating agreement. Under this agreement, Louisiana Generating and Entergy Gulf States are each entitled to their ownership percentage of the hourly net electrical output of Big Cajun II, Unit 3. All fixed costs are shared in proportion to the ownership interests. Fixed costs include the cost of operating common facilities. All variable costs are incurred in proportion to the energy delivered to the owners. NRG Energy's income statement includes its share of all fixed and variable costs of operating the unit. NRG Energy's 58% share of the original cost included in Property, Plant and Equipment and construction in progress at December 31, 2002 and 2001, was

$189.0 million and $179.7 million, respectively. The corresponding accumulated depreciation and amortization at December 31, 2002 and 2001, was $12.3 million and $7.8 million, respectively.

In August 2001, NRG Energy completed the acquisition of a 77% interest in the 520 MW gas fired electric generating facility located in McClain County, Oklahoma from Duke Energy North America LLC (McClain generating facility). The remaining 23% of the McClain generating facility is owned and operated by the Oklahoma Municipal Power Authority (OMPA) pursuant to a joint ownership and operating agreement. Under this agreement, NRG McClain LLC operates the facility and NRG Energy and OMPA are entitled to their ownership ratio of the net available output of the McClain facility. All fixed costs are shared in proportion to the ownership interests. All variable costs are incurred in proportion to the energy delivered to the owners. NRG Energy's income statement includes its share of all fixed and variable costs of operating the facilities. NRG Energy's 77% share of the original cost included in Property, Plant and Equipment and construction in progress at December 31, 2002 and 2001 was $277.6 million and $277.3 million, respectively. The corresponding accumulated depreciation and amortization at December 31, 2002 and 2001, was $12.3 million and $3.1 million, respectively.

In June 2001, NRG Energy completed the acquisition of an approximately 3.7% interest in both the Keystone and Conemaugh coal-fired generating facilities. The Keystone and Conemaugh facilities are located near Pittsburgh, Pennsylvania and are jointly owned by a consortium of energy companies. NRG Energy purchased its interests from Conectiv, Inc. Keystone and Conemaugh are operated by GPU Generation, Inc. which sold its assets and operating responsibilities to Sithe Energies. Keystone and Conemaugh both consist of two operational coal-fired steam power units with a combined net output of 1,700 MW, four diesel units with a combined net output of 11 MW and an on-site landfill. The units are operated pursuant to a joint ownership participation and operating agreement. Under this agreement each joint owner is entitled to its ownership ratio of the net available output of the facility. All fixed costs are shared in proportion to the ownership interests. All variable costs are incurred in proportion to the energy delivered to the owners. NRG Energy's income statement includes its share of all fixed and variable costs of operating the facilities. NRG Energy's 3.70% and 3.72% share of the Keystone and Conemaugh facilities original cost included in Property, Plant and Equipment and construction in progress at December 31, 2002 was $57.9 million and $62.8 million, respectively and for December 31, 2001 $52.9 million and $60.9 million, respectively. The corresponding accumulated depreciation and amortization at December 31, 2002 and 2001, for Keystone and Conemaugh was $3.5 million and $4.1 million, respectively, and for December 31, 2001 $1.3 million and $1.5 million, respectively.

Note 25 — Decommissioning Funds

NRG Energy is required by the State of Louisiana Department of Environmental Quality ("DEQ") to rehabilitate NRG Energy's 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 (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. Cumulative contributions to the Solid Waste Disposal Trust Fund and earnings on the investments therein are accrued as a decommissioning liability. At December 31, 2002 and 2001, the carrying value of the trust fund investments and the related accrued decommissioning liability was approximately $4.6 million and $4.3 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.

Note 26 — Accounting for Derivative Instruments and Hedging Activities

Derivative Instruments and Hedging Activity

On January 1, 2001, NRG Energy adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 137 and SFAS No. 138. SFAS No. 133 requires NRG Energy to record all derivatives on the balance sheet at fair value. Changes in the fair value of non-hedge derivatives will be immediately recognized in earnings. Changes in fair values of derivatives accounted for as hedges will either be recognized in earnings as offsets to the changes in fair value of related hedged assets, liabilities and firm commitments or, for forecasted transactions, deferred and recorded as a component of other accumulated comprehensive income (OCI) until the hedged transactions occur and are recognized in earnings. The ineffective portion of a hedging derivative instrument's change in fair value will be immediately recognized in earnings. NRG Energy also formally assesses both at inception and at least quarterly thereafter, whether the derivatives that are used in hedging transactions are highly effective in offsetting the changes in either the fair value or cash flows of the hedged item. This assessment includes all components of each derivative's gain or loss unless otherwise noted. When it is determined that a derivative ceases to be a highly effective hedge, hedge accounting is discontinued.

SFAS No. 133 applies to NRG Energy's long-term power sales contracts, long-term gas purchase contracts and other energy related commodities financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect investments in fuel inventories. SFAS No. 133 also applies to various interest rate swaps used to mitigate the risks associated with movements in interest rates and foreign exchange contracts to reduce the effect of fluctuating foreign currencies on foreign denominated investments and other transactions. At December 31, 2002, NRG Energy had various commodity contracts extending through December 2003, and several fixed-price gas and electricity purchase contracts extending through 2018.

Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS No. 133 on NRG Energy's Other Comprehensive Income balance as of December 31, 2002:

	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in $ thousands)			
Accum. OCI balance at December 31, 2001.	$134,868	$(61,404)	$(2,363)	$ 71,101
Unwound from OCI during period:				
— due to forecasted transactions probable of no longer occurring	—	18,784	—	18,784
— due to unwinding of previously deferred amounts	(96,617)	10,007	2,075	(84,535)
Mark to market of hedge contracts	59,473	(38,572)	27	20,928
Accum. OCI balance at December 31, 2002.	$ 97,724	$(71,185)	$ (261)	$26,278
Gains/(Losses) expected to unwind from OCI during next 12 months	$ (8,916)	$ 9,861	$ 261	$ 1,206

During the year ended December 31, 2002, NRG Energy reclassified losses of $18.8 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 $84.5 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, NRG Energy recorded a gain in OCI of approximately $20.9 million related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133 as of December 31, 2002 was an unrecognized gain of approximately $26.3 million. NRG Energy expects $1.2 million of deferred net losses on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

The following table summarizes the effects of SFAS No. 133 on NRG Energy's Other Comprehensive Income balance as of December 31, 2001:

	Energy Commodities	Interest Rate	Foreign Currency	Total
		(Gains/(Losses) in $ thousands)		
Accum. OCI balance at December 31, 2000	$ —	$ —	$ —	$ —
Initial adoption of SFAS No. 133.	(6,567)	(16,064)	—	(22,631)
Unwound from OCI during period:				
— due to unwinding of previously deferred amounts	(25,789)	662	(167)	(25,294)
Mark to market of hedge contracts	167,224	(46,002)	(2,196)	119,026
Accum. OCI balance at December 31, 2001	$134,868	$(61,404)	$(2,363)	$ 71,101

The adoption of SFAS No. 133 on January 1, 2001, resulted in an after-tax unrealized loss of $22.6 million recorded to OCI related to previously deferred net losses on derivatives designated as cash flow hedges. During the year ended December 31, 2001, NRG Energy reclassified gains of $25.3 million from OCI to current-period earnings. This amount is recorded on the same line in the statement of operations in which the hedged item is recorded. Also during the year ended December 31, 2001, NRG Energy recorded an after-tax gain in OCI of approximately $119.0 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, 2001 was an unrecognized gain of approximately $71.1 million.

Statement of Operations

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

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

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

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

Energy Related Commodities

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

No ineffectiveness was recognized on commodity cash flow hedges during the periods ended December 31, 2002 and 2001.

NRG Energy's pre-tax earnings for the years ended December 31, 2002 and 2001 were increased by an unrealized gain of $20.0 million and $14.1 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the years ended December 31, 2002 and 2001, NRG Energy reclassified gains of $96.6 million and $25.8 million, respectively, from OCI to current-period earnings and expects to reclassify an additional $8.9 million of deferred gains to earnings during the next twelve months on energy related derivative instruments accounted for as hedges.

Interest Rates

To manage interest rate risk, NRG Energy has entered into interest-rate swaps that effectively fix the interest payments of certain floating rate debt instruments. Interest-rate swap agreements are accounted for as cash flow hedges. The effective portion of the cumulative gain or loss on the derivative instrument is reported as a component of OCI in shareholders' equity and recognized into earnings as the underlying interest expense is incurred. Such reclassifications are included on the same line of the statement of operations in which the hedged item is recorded.

No ineffectiveness was recognized on interest rate cash flow hedges during the periods ended December 31, 2002 and 2001.

NRG Energy's pre-tax earnings for the years ended December 31, 2002 and 2001 were increased by an unrealized loss of $32.0 million and $0, respectively, associated with changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the years ended December 31, 2002 and 2001, NRG Energy reclassified losses of $28.8 million and $0.7 million, respectively, from OCI to current-period earnings and expects to reclassify $9.9 million of deferred losses to earnings during the next twelve months on interest rate swaps accounted for as hedges.

Foreign Currency Exchange Rates

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

No ineffectiveness was recognized on foreign currency cash flow hedges during the periods ended December 31, 2002 and 2001.

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

During the years ended December 31, 2002 and 2001, NRG Energy reclassified losses of $2.1 million and gains of $0.2 million, respectively, from OCI to current period earnings and expects to reclassify $0.3 million of deferred losses to earnings during the next twelve months on foreign currency swaps accounted for as hedges.

Note 27 — Unaudited Quarterly Financial Data

Subsequent to the issuance of NRG Energy's financial statements for the quarter ended September 30, 2002, NRG Energy's management determined that the accounting for certain transactions required restatement.

NRG Energy determined that it had misapplied the provisions of SFAS No. 144 related to asset groupings in connection with the review for impairment of its long-lived assets during the quarter ended September 30, 2002. SFAS No. 144 requires that for purposes of testing recoverability, assets be grouped at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets. NRG Energy recalculated the asset impairment tests in accordance with SFAS No. 144 using the appropriate asset groupings for independent cash flows for each generation facility. As a result, NRG Energy concluded that asset impairments should have been recorded for two projects known as Bayou Cove Peaking Power LLC and Somerset Power LLC. Since NRG Energy concluded that the triggering events that led to the impairment charge were experienced in the third quarter of 2002, the asset impairments related to these projects should have been recorded as of September 30, 2002. NRG Energy calculated the asset impairment charges for Bayou Cove Peaking Power LLC and Somerset Power LLC to be $126.5 million and $49.3 million, respectively.

In connection with NRG Energy's year-end audit, two additional items were found to be inappropriately recorded as of September 30, 2002. These items included the inappropriate treatment of interest rate swap transactions as cash flow hedges and the decrease in the value of a bond remarketing option from the original price paid by NRG Energy. The error correction for the interest rate swaps resulted in the recording of additional income of $61.6 million as of September 30, 2002. The recognition of the decrease in the value of the remarketing option resulted in a charge to income of $15.9 million as of September 30, 2002.

A summary of the significant effects of the restatement on our consolidated statements of operations for the three and nine months ended September 30, 2002 is as follows:

	Previously Reported**		As Restated	
	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended
	(In thousands)			
Consolidated Statements of Operations:				
Revenue and equity earnings	$ 653,272	$ 1,671,775	$ 653,272	$ 1,671,775
Operating income	(2,314,505)	(2,210,479)	(2,506,198)	(2,402,172)
Net loss from continuing operations	(2,338,856)	(2,397,559)	(2,468,936)	(2,527,639)
Net loss from discontinued operations	(586,458)	(595,570)	(586,458)	(595,570)
Net loss	(2,925,314)	(2,993,129)	(3,055,394)	(3,123,209)

** As reclassified for discontinued operations.

During the fourth quarter of 2002, NRG Energy determined that it had inadvertently offset its investment in Jackson County, MS, bonds in the amount of $155.5 million against long-term debt of the same amount owed to the County. This resulted in an understatement of the Company's assets by $155.5 million and liabilities by $155.5 million as of September 30, 2002. In addition, the restatement for Bayou Cove Peaking LLC and Somerset Power LLC impairments reduced the previously reported net property, plant and equipment balance by $175.8 million. The restatement for the interest rate swaps had no impact on total shareholder's equity and the restatement for the remarketing option reduced other assets by $15.9 million.

A summary of the significant effects of the restatement on our consolidated balance sheet as of September 30, 2002 is as follows:

	As of September 30, 2002	
	Previously Reported**	As Restated
	(In thousands)	
Consolidated Balance Sheet:		
Property, Plant and Equipment		
In service	$ 6,587,862	$ 6,406,893
Under construction	593,744	592,031
Total property, plant and equipment	7,181,606	6,998,924
Less accumulated depreciation	(563,152)	(556,287)
Net property, plant and equipment	6,618,454	6,442,637
Notes receivable, less current portion	606,527	762,004
Other assets, net	49,068	33,192
Long term debt	1,659,322	1,814,799
Retained deficit	(2,357,780)	(2,487,860)
Accumulated other comprehensive loss	(4,879)	(66,492)

** As reclassified for discontinued operations

Summarized quarterly unaudited financial data is as follows:

	Quarter Ended 2002				
	Mar 31	June 30	Sept 30	Dec 31	Total Year
			Restated (Thousands of dollars)		
Revenue and equity earnings	$459,258	$559,245	$ 653,272	$ 485,653	$ 2,157,428
Operating income/(loss)	44,350	59,676	(2,506,198)	(135,652)	(2,537,824)
Net loss from continuing operations	(29,697)	(29,006)	(2,468,936)	(328,577)	(2,856,216)
Net income/(loss) from discontinued operations	3,234	(12,346)	(586,458)	(12,496)	(608,066)
Net loss	(26,463)	(41,352)	(3,055,394)	(341,073)	(3,464,282)

	Quarter Ended 2001				
	Mar 31	June 30	Sept 30	Dec 31	Total Year
			Restated (Thousands of dollars)		
Revenue and equity earnings	$506,710	$599,614	$808,129	$486,731	$2,401,184
Operating income	101,038	133,601	291,330	106,946	632,915
Net income from continuing operations	20,631	38,090	135,652	29,429	223,802
Net income from discontinued operations	14,547	11,024	5,928	9,903	41,402
Net income	35,178	49,114	141,580	39,332	265,204

During the fourth quarter of the year ended December 31, 2002, NRG Energy recorded $100.3 million of special charges including additional asset impairments and other restructuring costs. In addition, NRG Energy recorded $74.2 million of write downs and losses on sale of equity investments.

Note 28 — Subsequent Event

Brazos Valley — In January 2003, the project lenders foreclosed on NRG Energy's ownership interests in NRG Brazos Valley GP, LLC, NRG Brazos Valley LP, LLC, NRG Brazos Valley Technology LP, LLC and NRG Brazos Valley Energy, LP, and the lenders thereby acquired all of the assets of the Brazos Valley project, a 633 MW project under construction near Houston, TX. NRG Energy agreed to the consensual foreclosure of the companies. NRG Energy received no cash proceeds upon completion of the foreclosure. As of December 31, 2002, NRG Energy recorded $24.0 million for the potential obligation to infuse additional amounts of capital to fund a debt service reserve account and the potential obligation to satisfy a contingent equity agreement.

Note 29 — Subsequent Event — NRG Energy Bankruptcy Filing

On May 14, 2003, NRG and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. On that date, we filed a plan of reorganization providing for the reorganization of five of the debtors: NRG Energy, Inc., NRG Power Marketing Inc., NRG Capital LLC, NRG Finance Company I LLC, or NRG FinCo, and NRGenerating Holdings (No. 23) B.V. (collectively the NRG Plan Debtors). No NRG Energy international operations were included in the filing. The plan of reorganization for the NRG Plan Debtors (the NRG plan of reorganization) generally provides for the elimination of 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, up to $540.0 million in cash and $500.0 million of new debt among our unsecured creditors.

On September 17, 2003, a plan of reorganization was filed for (i) NRG Northeast Generating LLC and its debtor subsidiaries (collectively NRG Northeast), (ii) NRG South Central Generating LLC and its debtor subsidiaries (collectively NRG South Central) and (iii) Berrians I Gas Turbine Power LLC (Berrians and, collectively with NRG Northeast and NRG South Central, the Northeast/ South Central Debtors). The plan of reorganization for the Northeast/ South Central Debtors (the Northeast/ South Central plan of reorganization) generally provides for payment in full to holders of allowed secured claims in cash on or around the effective date of the Northeast/ South Central plan of reorganization. Holders of allowed general unsecured claims will receive either (i) cash equal to the unpaid portion of their allowed unsecured claim, (ii) treatment that leaves unaltered the legal, equitable and contractual rights to which such unsecured claim entitles the holder of such claim, (iii) treatment that otherwise renders such unsecured claim unimpaired pursuant to section 1124 of the bankruptcy code or (iv) such other, less favorable treatment that is confirmed in writing as being acceptable to such holder and to the applicable debtor.

An order confirming the NRG plan of reorganization was entered by the bankruptcy court on November 24, 2003 and NRG Energy anticipates the plan will become effective on or about December 5, 2003. On November 25, 2003, an order confirming the Northeast/ South Central plan of reorganization was entered by the bankruptcy court and NRG Energy anticipates that the Northeast/ South Central plan of reorganization will become effective in late 2003 or early 2004.

FirstEnergy — During the third quarter of 2003, NRG Energy recorded $396.0 million in connection with the resolution of the FirstEnergy Arbitration Claim. As a result of this resolution, FirstEnergy will retain ownership of the Lake Plant Assets and will receive an allowed general unsecured claim of $396 million under NRG Energy's Plan of Reorganization submitted to the Bankruptcy Court.

Note 30 — Subsequent Discontinued Operations — McClain, TERI and NEO Landfill Gas Inc.

During 2003, pursuant to the requirements of SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Live Assets," the following projects have met the required criteria to be classified and accounted for as held-for-sale; McClain, TERI and NLGI. Accordingly, the assets, liabilities and results of operations of these entities have been reclassified and accounted for as held-for-sale. In addition, the following footnotes have been adjusted to reflect the held-for-sale treatment of these projects in order for each footnote to agree to the respective restated balance sheets and statements of operation.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003 (Restated)	2002 (Restated)	2003 (Restated)	2002 (Restated)
	(In thousands)			
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 608,009	$ 627,352	$ 1,616,869	$ 1,602,859
Equity in earnings of unconsolidated affiliates	63,272	25,920	155,758	68,916
Total operating revenues and equity earnings	671,281	653,272	1,772,627	1,671,775
Operating Costs and Expenses				
Cost of majority-owned operations	401,290	424,251	1,186,241	1,064,021
Depreciation and amortization	64,476	64,141	203,050	176,686
General, administrative and development	36,609	65,463	128,010	171,855
Write downs and (gains) losses on sales of equity method investments	(12,310)	117,869	136,717	127,715
Legal settlement	396,000	—	396,000	—
Reorganization items	20,698	—	27,032	—
Restructuring and impairment charges	6,252	2,487,746	298,019	2,533,670
Total operating costs and expenses	913,015	3,159,470	2,375,069	4,073,947
Operating (Loss)	(241,734)	(2,506,198)	(602,442)	(2,402,172)
Other Income (Expense)				
Minority interest in earnings of consolidated subsidiaries	(1,166)	(637)	(2,415)	(1,317)
Other income (expense), net	6,090	7,464	7,316	14,441
Restructuring interest income	478	—	608	—
Interest expense	(42,367)	(66,470)	(317,984)	(289,346)
Total other expense	(36,965)	(59,643)	(312,475)	(276,222)
Loss From Continuing Operations Before Income Taxes	(278,699)	(2,565,841)	(914,917)	(2,678,394)
Income Tax Expense (Benefit)	4,991	(96,905)	44,864	(150,755)
Loss From Continuing Operations	(283,690)	(2,468,936)	(959,781)	(2,527,639)
(Loss)/ Income on Discontinued Operations, Net of Income Taxes	(1,104)	(586,458)	53,954	(595,570)
Net Loss	$(284,794)	$ (3,055,394)	$ (905,827)	$ (3,123,209)

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2003	December 31, 2002
	(In thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 292,644	$ 381,514
Restricted cash	487,644	277,489
Accounts receivable — trade, less allowance for doubtful accounts of $11,069 and $18,163	383,631	273,944
Current portion of notes receivable — affiliates	—	2,442
Current portion of notes receivable	1,639	3,000
Income tax receivable	19,092	4,320
Inventory	255,803	265,585
Derivative instruments valuation	543	28,791
Prepayments and other current assets	166,952	138,567
Current assets — discontinued operations	35,842	119,509
Total current assets	1,643,790	1,495,161
Property, Plant and Equipment		
In service	6,364,407	6,499,685
Under construction	460,989	623,750
Total property, plant and equipment	6,825,396	7,123,435
Less accumulated depreciation	(771,613)	(602,712)
Net property, plant and equipment	6,053,783	6,520,723
Other Assets		
Equity investments in affiliates	954,602	884,263
Notes receivable, less current portion — affiliates	168,185	206,308
Notes receivable, less current portion	813,006	778,945
Intangible assets, net of accumulated amortization of $25,126 and $22,110	72,424	76,639
Debt issuance costs, net of accumulated amortization of $62,143 and $49,670	140,119	136,346
Derivative instruments valuation	80,543	90,766
Other assets, net of accumulated amortization of $4,095 and $4,250	34,866	24,810
Non-current assets — discontinued operations	213,454	678,822
Total other assets	2,477,199	2,876,899
Total Assets	$10,174,772	$10,892,783

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS — (Continued)

(Unaudited)

	September 30, 2003	December 31, 2002
	(In thousands)	
LIABILITIES AND STOCKHOLDER'S DEFICIT		
Liabilities Not Subject to Compromise		
Current Liabilities		
Current portion of long-term debt	$ 1,444,450	$ 7,026,771
Revolving line of credit	—	1,000,000
Project-level, non-recourse debt	18,991	30,064
Accounts payable — trade	307,641	556,712
Accounts payable — affiliate	28,948	50,659
Accrued property, sales and other taxes	27,227	24,420
Accrued salaries, benefits and related costs	20,768	21,018
Accrued interest	46,103	289,553
Derivative instruments valuation	649	13,439
Other current liabilities	81,190	110,645
Current liabilities — discontinued operations	113,339	694,464
Total current liabilities	2,089,306	9,817,745
Other Liabilities		
Long-term debt	1,188,599	1,184,287
Deferred income taxes	178,197	91,634
Postretirement and other benefit obligations	45,852	67,495
Derivative instruments valuation	69,731	91,039
Other long-term obligations	143,053	154,710
Minority interest	32,151	29,625
Non-current liabilities — discontinued operations	22,773	152,447
Total liabilities not subject to compromise	3,769,662	11,588,982
Liabilities Subject to Compromise		
Financing debt	6,409,964	—
Accounts payable — trade	157,855	—
Accounts payable — affiliate	68,989	—
Accrued liabilities	1,071,527	—
Other liabilities	68,882	—
Liabilities — discontinued operations	159,110	—
Total liabilities subject to compromise	7,936,327	—
Commitments and Contingencies		
Stockholder's Deficit Class A — common stock; $.01 par value; 100 shares authorized; 3 shares at September 30, 2003 and at December 31, 2002 issued and outstanding	—	—
Common stock; $.01 par value; 100 shares authorized, 1 share at September 30, 2003 and at December 31, 2002 issued and outstanding	—	—
Additional paid-in capital	2,227,692	2,227,692
Retained deficit	(3,734,760)	(2,828,933)
Accumulated other comprehensive loss	(24,149)	(94,958)
Total stockholder's deficit	(1,531,217)	(696,199)
Total Liabilities and Stockholder's Deficit	$10,174,772	$10,892,783

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDER'S (DEFICIT)/ EQUITY

For the Three Months Ended September 30, 2003 and September 30, 2002
(Unaudited)

	Class A Common		Common		Additional Paid-in Capital	Retained (Deficit)/Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholder's Deficit
	Stock	Shares	Stock	Shares				
					(In thousands)			
Balances at June 30, 2002	$ —	—	$ —	—	$2,227,692	$ 567,534	$ (9,306)	$ 2,785,920
Net Loss						(3,055,394)		(3,055,394)
Foreign currency translation adjustments and other							(34,598)	(34,598)
Deferred unrealized loss on derivatives, net							(22,588)	(22,588)
Comprehensive loss for the three months ended September 30, 2002								(3,112,580)
Balances at September 30, 2002, as restated	$ —	—	$ —	—	$2,227,692	$(2,487,860)	$ (66,492)	$ (326,660)
Balances at June 30, 2003	$ —	—	$ —	—	$2,227,692	$(3,449,966)	$ (56,072)	$(1,278,346)
Net Loss						(284,794)		(284,794)
Foreign currency translation adjustments and other							(3,133)	(3,133)
Deferred unrealized gain on derivatives, net							35,056	35,056
Comprehensive loss for the three months ended September 30, 2003								(252,871)
Balances at September 30, 2003	$ —	—	$ —	—	$2,227,692	$(3,734,760)	$ (24,149)	$ (1,531,217)

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDER'S (DEFICIT)/ EQUITY

For the Nine Months Ended September 30, 2003 and September 30, 2002
(Unaudited)

	Class A Common		Common		Additional Paid-in Capital	Retained (Deficit)/ Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholder's Deficit
	Stock	Shares	Stock	Shares				
					(In thousands)			
Balances at December 31, 2001	$ 1,476	147,605	$ 509	50,939	$ 1,713,984	$ 635,349	$ (114,189)	$ 2,237,129
Net Loss						(3,123,209)		(3,123,209)
Foreign currency translation adjustments and other							53,304	53,304
Deferred unrealized loss on derivatives, net							(5,607)	(5,607)
Comprehensive loss for the nine months ended September 30, 2002								(3,075,512)
Contribution from parent					502,874			502,874
Issuance of common stock, net			6	591	8,843			8,849
Impact of exchange offer	(1,476)	(147,605)	(515)	(51,530)	1,991			
Balances at September 30, 2002, as restated	$ —	—	$ —	—	$2,227,692	$(2,487,860)	$ (66,492)	$ (326,660)
Balances at December 31, 2002	$ —	—	$ —	—	$2,227,692	$(2,828,933)	$ (94,958)	$ (696,199)
Net Loss						(905,827)		(905,827)
Foreign currency translation adjustments and other							87,734	87,734
Deferred unrealized loss on derivatives, net							(16,925)	(16,925)
Comprehensive loss for the nine months ended September 30, 2003								(835,018)
Balances at September 30, 2003	$ —	—	$ —	—	$2,227,692	$(3,734,760)	$ (24,149)	$ (1,531,217)

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
	2003	2002 (Restated)
	(In thousands)	
Cash Flows from Operating Activities		
Net loss	$(905,827)	$(3,123,209)
Adjustments to reconcile net loss to net cash provided (used) by operating activities		
Undistributed equity in earnings of unconsolidated affiliates	(47,500)	(15,344)
Depreciation and amortization	211,201	207,751
Amortization of deferred financing costs	14,306	20,463
Deferred income taxes and investment tax credits	18,502	(186,300)
Minority interest	2,010	(26,791)
Unrealized gains on energy contracts	(12,500)	(47,747)
Asset impairment	353,871	3,156,610
Write down and (gains)/loss on sale of equity method investments	136,531	122,037
(Gain)/loss on sale of discontinued operations	(217,920)	17,099
Amortization of assumed out of market power contracts	—	(34,949)
Cash provided (used) by changes in certain working capital items, net of acquisition effects		
Accounts receivable	(103,377)	(96,779)
Accounts receivable — affiliates	—	(8,478)
Accrued income taxes	(16,495)	24,510
Inventory	12,314	64,965
Prepayments and other current assets	(28,748)	(50,280)
Accounts payable	618,099	281,102
Accounts payable — affiliates	36,571	—
Accrued property, sales and other taxes	1,733	4,708
Accrued salaries, benefits and related costs	(10,605)	(32,257)
Accrued interest	129,585	75,266
Other current liabilities	(118,365)	24,041
Cash used by changes in other assets and liabilities	47,929	12,089
Net Cash Provided by Operating Activities	121,315	388,507
Cash Flows from Investing Activities		
Proceeds on sale of discontinued operations	1,011	—
Proceeds from sale of equity method investments	102,546	29,313
Proceeds on sale of subsidiaries	1,000	—
Investments in equity method investments and projects	(369)	(35,402)
Decrease/(increase) in notes receivable (net)	9,450	(189,698)
Capital expenditures	(85,635)	(1,391,019)
Increase in restricted cash	(188,127)	(65,316)
Net Cash Used by Investing Activities	(160,124)	(1,652,122)
Cash Flows from Financing Activities		
Proceeds from issuance of stock, net	—	4,065
Net borrowings under line of credit agreements	—	790,000
Proceeds from issuance of long-term debt, net	43,797	1,251,530
Deferred debt issuance costs	(17,843)	—
Capital contributions from parent	—	500,000
Principal payments on short and long-term debt	(50,073)	(1,111,621)
Net Cash (Used) Provided by Financing Activities	(24,119)	1,433,974
Change in Cash from Discontinued Operations	26,595	18,325
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(52,537)	31,813

Net (Decrease) Increase in Cash and Cash Equivalents	(88,870)	220,497
Cash and Cash Equivalents at Beginning of Period	381,514	105,405
Cash and Cash Equivalents at End of Period	$ 292,644	$ 325,902

See notes to consolidated financial statements.

NRG Energy Inc. (NRG Energy or the Company) is an energy 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. NRG Energy is a wholly owned subsidiary of Xcel Energy Inc. (Xcel Energy). Xcel Energy directly owns six utility subsidiaries that serve electric and natural gas customers in 12 states. Xcel Energy also owns or has an interest in a number of non-regulated businesses, the largest of which is NRG Energy.

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission's (SEC) regulations for interim financial information and with the instructions to Form 10-Q. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. The accounting policies followed by NRG Energy are set forth in Note 2 to the Company's financial statements in its Annual Report on Form 10-K for the year ended December 31, 2002 (Form 10-K). The following notes should be read in conjunction with such policies and other disclosures in the Form 10-K. Interim results are not necessarily indicative of results for a full year.

On May 14, 2003 (the Petition Date) NRG Energy and 26 of its affiliates (the Debtors) filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code (the Bankruptcy Code) in the United States Bankruptcy Court for the Southern District of New York (the Bankruptcy Court) in re: NRG ENERGY, INC., et al., Case No. 03-13024 (PCB) (such proceedings, the Chapter 11 Cases). See Note 2 for a complete list of debtors. It is possible that additional subsidiaries will file petitions for reorganization under Chapter 11. Since the Petition Date, three additional subsidiaries have filed for reorganization under Chapter 11 of the Bankruptcy Code. International operations and certain other subsidiaries were not included in the filing. NRG Energy expects operations to continue as normal during the restructuring process, while it operates its business as a "debtor-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. For more information about NRG Energy's restructuring process, refer to the Form 10-K filed by NRG Energy on March 31, 2003, Form 10-Q's filed by NRG Energy on May 20, 2003 and August 14, 2003.

The consolidated financial statements have been prepared on a "going concern" basis in accordance with GAAP. The "going concern" basis of presentation assumes that NRG Energy will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities in the normal course of business. Because of the Chapter 11 Cases and the circumstances leading to the filing thereof, NRG Energy's ability to continue as a "going concern" is subject to substantial doubt and is dependent upon, among other things, confirmation of a plan of reorganization, NRG Energy's ability to comply with the terms of, and if necessary renew at its expiry in May 2004, the Debtor in Possession Credit Facility, and NRG Energy's ability to generate sufficient cash flows from operations, asset sales and financing arrangements to meet its obligations. There can be no assurance that this can be accomplished and if it were not, NRG Energy's ability to realize the carrying value of its assets and discharge its liabilities would be subject to substantial uncertainty. Therefore, if the "going concern" basis were not used for the financial statements, then significant adjustments could be necessary to the carrying value of assets and liabilities, the revenues and expenses reported, and the balance sheet classifications used.

The consolidated financial statements also have been prepared in accordance with The American Institute of Certified Public Accountants Statement of Position 90-7 ("SOP 90-7"), *"Financial Reporting by Entities in Reorganization under the Bankruptcy Code".* Accordingly, all prepetition liabilities believed to be subject to compromise have been segregated in the consolidated balance sheet and classified as liabilities subject to compromise, at the estimated amount of allowable claims. Liabilities not believed to be subject to compromise are separately classified as current and non-current. Interest expense is reported only to the extent that it will be paid or that it is probable that it will be an allowed claim.

In the opinion of management, the accompanying unaudited interim consolidated financial statements contain all material adjustments necessary to present fairly the consolidated financial position of NRG Energy as of September 30, 2003 and December 31, 2002, the results of its operations and stockholder's deficit for the three and nine months ended September 30, 2003 and 2002, and its cash flows for the nine months ended September 30, 2003 and 2002.

Certain prior-year amounts have been reclassified for comparative purposes. As previously disclosed in NRG Energy's 10-K filed on March 31, 2003, NRG Energy's results of operations for the three and nine months ended September 30, 2002 have been restated to reflect the impairment of Somerset Power and Bayou Cove Peaking Power. The effect of these restatements are disclosed in Note 20. In addition, NRG Energy's results of operations for the three and nine months ended September 30, 2003 have been restated to reclassify $396 million from reorganization items to legal settlement in the consolidated statements of operations.

1. Restructuring Activities

During 2002, Xcel Energy contributed $500 million to NRG Energy, and NRG Energy and its subsidiaries sold assets and businesses that provided NRG Energy in excess of $286 million in cash and eliminated approximately $432 million in debt. NRG Energy also cancelled or deferred construction of approximately 3,900 MW of new generation projects. On July 26, 2002, Standard & Poor's (S&P) downgraded NRG Energy's senior unsecured bonds to below investment grade, and three days later Moody's also downgraded NRG Energy's senior unsecured debt rating to below investment grade. Currently, NRG Energy's unsecured bonds carry a rating of D at S&P and Ca at Moody's.

In August 2002, NRG Energy retained financial and legal restructuring advisors to assist its management in the preparation of a comprehensive financial and operational restructuring. In November 2002, NRG Energy and Xcel Energy presented a comprehensive plan of restructuring to an ad hoc committee of its bondholders and a steering committee of its bank lenders (the Ad Hoc Creditors Committees). The restructuring plan served as a basis for continuing negotiations between the Ad Hoc Creditors Committees, NRG Energy and Xcel Energy related to a consensual plan of reorganization for NRG Energy.

On March 26, 2003, Xcel Energy announced that its board of directors had approved a tentative settlement agreement with holders of most of NRG Energy's long-term notes and the steering committee representing NRG Energy's bank lenders. The terms of the settlement call for Xcel Energy to make payments to NRG Energy totaling up to $752 million for the benefit of NRG Energy's creditors in consideration for their waiver of any existing and potential claims against Xcel Energy. Under the settlement, Xcel Energy would make the following payments: (i) $350 million, up to $150 million of which may be in Xcel Energy common stock if Xcel Energy's public debt fails to maintain a certain rating, on the later of: (a) 90 days after NRG Energy's plan of reorganization is confirmed by the Bankruptcy Court, and (b) one day after the effective date of NRG Energy's plan of reorganization; (ii) $50 million in the first quarter of 2004. At Xcel Energy's option, it may fill this requirement with either cash or Xcel Energy common stock or any combination thereof; and (iii) up to $352 million in April 2004. Since the announcement on March 26, 2003, representatives of NRG Energy, Xcel Energy, the bank lenders and noteholders continued to meet to draft the definitive documentation necessary to fully implement the terms and conditions of the tentative settlement agreement. The final settlement agreement between Xcel Energy and NRG Energy is subject to the Bankruptcy Court approval including certain provisions and conditions in its order approving the confirmation of NRG Energy's plan of reorganization and the satisfaction, or waiver by Xcel Energy, of certain other conditions (including obtaining requisite releases of Xcel Energy by NRG Energy creditors). There can be no assurance that such conditions will be met.

As noted above, on May 14, 2003, the Debtors filed the Chapter 11 Cases. NRG Energy expects operations to continue as normal during the restructuring process, while it operates its business as a "debtor-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. In connection with its Chapter 11 filing, NRG Energy also announced that it had secured a $250 million debtor-in-possession (DIP) financing facility from GE Capital Corporation, subject to Bankruptcy Court approval, to be utilized by its NRG Northeast Generating LLC subsidiary (NRG Northeast) and certain NRG Northeast subsidiaries. The Bankruptcy Court entered an order approving the DIP facility on July 24, 2003. NRG Energy anticipates that the DIP, together with its cash reserves and its ongoing revenue stream, will be sufficient to fund its operations, including payment of employee wages and benefits, during the negotiation process.

Subsequent to the Petition Date, additional NRG Energy subsidiaries filed petitions for reorganization with the Bankruptcy Court. On June 5, 2003, NRG Nelson Turbines LLC and LSP-Nelson Energy LLC (both wholly owned subsidiaries of NRG Energy) filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. On August 19, 2003, NRG McClain LLC (a wholly owned subsidiary of NRG Energy) filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court.

On May 15, 2003, NRG Energy announced that it had been notified that the New York Stock Exchange (NYSE) has suspended trading in NRG Energy's corporate units that trade under the ticker symbol NRZ (Units) and that an application to the Securities and Exchange Commission to delist the Units is pending the completion of applicable procedures, including appeal by NRG Energy of the NYSE staff's decision. NRG Energy does not plan to make such an appeal. The NYSE took this action following NRG Energy's announcement that it and certain of its affiliates had filed voluntary positions for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

In addition, on May 15, 2003, NRG Energy, NRG Power Marketing, Inc. (NRG PMI), NRG Finance Company I LLC, NRGenerating Holdings (No. 23) B.V. and NRG Capital LLC (collectively, the Plan Debtors) filed their Disclosure Statement for Reorganizing Debtors' Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code (as subsequently amended, the Disclosure Statement). The Bankruptcy Court held a hearing on the Disclosure Statement on June 30, 2003, and instructed the Plan Debtors to include certain additional disclosure. 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 (respectively, the Amended Disclosure Statement, the Plan) on October 14, 2003.

The Plan must be approved by the SEC prior to its becoming effective. As subsidiaries of a registered holding company (Xcel Energy) under the Public Utility Holding Company Act of 1935 (PUHCA), any reorganization plan for NRG Energy or NRG Energy's subsidiaries must be approved by the SEC prior to such plan becoming effective. Furthermore, each solicitation of any consent in respect of any reorganization plan must be accompanied or preceded by a copy of a report on the plan made by the SEC, or an abstract thereof made or approved by the SEC. The Plan and Amended Disclosure Statement were submitted to the SEC for review on July 28, 2003. The SEC issued an order approving the Plan on October 10, 2003, permitting the Plan Debtors, subject to the approval of the Bankruptcy Court, to commence solicitation of votes on the Plan.

The Plan Debtors commenced solicitation of votes on the Plan on October 14, 2003. The voting deadline by which holders of claims and equity interests of the Plan Debtors must submit their ballots accepting or rejecting the Plan was November 12, 2003. Objections to confirmation of the Plan must be filed with Bankruptcy Court by November 12, 2003. The Bankruptcy Court has scheduled the confirmation hearing to determine whether the Plan should be confirmed on November 21, 2003.

If the Plan is confirmed, holders of NRG Energy unsecured claims (including bank and bond debt) will receive a combination of New NRG Energy common stock, New NRG Energy senior notes and cash for an estimated percentage recovery of 50.7%. Holders of NRG PMI unsecured claims will receive a combination of New NRG Energy common stock and New NRG Energy senior notes for an estimated percentage recovery of 44.6%. If the Plan is confirmed, certain other holders of claims or equity interests in the Plan Debtors will (i) have their claims paid in full in accordance with the Bankruptcy Code, (ii) have their claims or equity interests reinstated, or (iii) have their claims or equity interests cancelled, and receive no distribution on account of such claims or equity interests. Upon emergence from bankruptcy, Xcel Energy's ownership interest in NRG Energy will be cancelled and ownership in NRG Energy will vest in the unsecured creditors of NRG Energy and NRG PMI.

On September 17, 2003, NRG Northeast Generating LLC (NRG Northeast) and NRG South Central Generating LLC (NRG South Central) and certain of their subsidiaries and affiliates filed a plan of reorganization with the Bankruptcy Court (the NRG Northeast and NRG South Central Plan). The debtors under the NRG Northeast and NRG South Central Plan are not soliciting votes for approval of the NRG Northeast and NRG South Central Plan because none of the holders of claims or equity interests are impaired under the NRG Northeast and NRG South Central Plan. The Bankruptcy Court has scheduled a hearing on the confirmation of the NRG Northeast and NRG South Central Plan on November 21, 24 and 25, 2003.

During the Chapter 11 Cases, the Debtors may, subject to any necessary Bankruptcy Court and lender approvals, sell assets and settle liabilities for amounts other than those reflected in the financial statements. The administrative and reorganization expenses resulting from Chapter 11 Cases will unfavorably affect the Debtors' results of operations. Future results of operations may also be adversely affected by other factors related to Chapter 11 Cases.

The Company is in the process of reconciling recorded prepetition liabilities with claims filed by creditors with the Bankruptcy Court. Differences resulting from that reconciliation process will be recorded as adjustments to prepetition liabilities. The Company recently began this process and has not yet determined the reorganization adjustments.

2. Debtors' Statements

As stated above, NRG Energy and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code on May 14, 2003, June 5, 2003, and August 19, 2003. As of the respective bankruptcy filing dates, the Debtors' financial records were closed for the Prepetition Period. As required by SOP 90-7 *"Financial Report by Entities in Reorganization under the Bankruptcy Code"*, below are the condensed combined financial statements of the Debtors since the date of the bankruptcy filings (the Debtors' Statements). The Debtors' Statements consist of the following entities: 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, NRG Nelson Turbines LLC, LSP-Nelson Energy LLC, Middletown Power LLC, Montville Power LLC, Northeast Generation Holding LLC, Norwalk Power LLC, NRG Capital LLC, NRG Central US LLC, NRG Eastern LLC, NRG Energy, Inc., NRG Finance Company I LLC, NRG McClain LLC, NRG New Roads Holdings LLC, NRG Northeast Generating LLC, NRG Power Marketing Inc., NRG South Central Generating LLC, NRGenerating Holdings No. 23 B.V., Oswego Harbor Power LLC, Somerset Power LLC, and South Central Generation Holding LLC. The Debtors' Statements have been prepared on the same basis as NRG Energy's Consolidated Financial Statements.

Debtors’ Condensed Combined Statement of Operations

	For the Three Months Ended September 30, 2003 (Restated)	For the Period from May 15, 2003 to September 30, 2003 (Restated)
	(In thousands)	
Operating revenue	$ 335,344	$ 523,412
Operating costs and expenses	753,979	964,796
Reorganization items	20,299	26,633
Operating loss	(438,934)	(468,017)
Equity in income (losses) of non-Debtor subsidiaries	170,959	(40,100)
Restructuring interest income	478	608
Other Expense	(16,608)	(12,340)
Pretax loss	(284,105)	(519,849)
Income tax (benefit) expense	(545)	621
Loss from continuing operations	(283,560)	(520,470)
Loss from discontinued operations, net of tax	(301)	(301)
Net loss	$ (283,861)	$ (520,771)

Debtors’ Condensed Combined Balance Sheet

	September 30, 2003
	(In thousands)
ASSETS	
Cash	$ 66,288
Receivables, net	289,551
Receivables, non-Debtor affiliates	147,234
Current portion of notes receivable	493,681
Other current assets	699,297
Total current assets	1,696,051
Property, plant and equipment, net	2,260,644
Investment in non-Debtors	2,087,593
Notes receivable, less current portion	157,317
Other assets	346,595
Total assets	$ 6,548,200
LIABILITIES AND STOCKHOLDER’S DEFICIT	
Other current liabilities	$ 140,584
Other long-term obligations	2,506
Liabilities subject to compromise	7,936,327
Total stockholder’s deficit	(1,531,217)
Total liabilities and stockholder’s deficit	$ 6,548,200

Debtors' Condensed Combined Statement of Cash Flows

	For the Period from May 15, 2003 to September 30, 2003
	(In thousands)
Net cash provided by operating activities	$ 144,342
Net cash used by investing activities	(196,379)
Net cash used by financing activities	—
Net increase in cash and cash equivalents	(52,037)
Cash and cash equivalents at beginning of period	118,325
Cash and cash equivalents at end of period	$ 66,288

3. Discontinued Operations

Pursuant to the requirements of SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets,"* NRG Energy has classified and is accounting for certain of its assets as held-for-sale at September 30, 2003. SFAS No. 144 requires that assets held for sale 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 NRG Energy's management considered projected cash flows, bids and offers related to those assets and businesses.

Discontinued operations consist of the historical operations and net gains/losses related to our Crockett Cogeneration, Entrade, Killingholme, Csepel, Hsin Yu, Bulo Bulo, McClain, NEO Landfill Gas, Inc. (NLGI) and Timber Energy Resources, Inc. (TERI) projects that were sold or have met the required criteria for such classification pending final disposition. Sales of four of the projects closed during 2002 (Bulo Bulo, Csepel, Entrade and Crockett Cogeneration). One project, Killingholme, was sold in January 2003. During 2003, NRG Energy committed to a plan to sell McClain and closed on the sale of TERI. In addition, in May 2003 the project lender foreclosed on NRG Energy's ownership interests in the wholly owned operating subsidiaries of NLGI.

The financial results for all of these businesses have been accounted for as discontinued operations. Accordingly, operating results of 2003 and of prior periods have been restated to report the operations as discontinued.

Summarized results of operations of the discontinued operations are presented in the following table. The three months ended September 2003 results of operations include the Hsin Yu, McClain, and TERI projects. The nine months ended September 2003 results of operations include the Killingholme, Hsin Yu, McClain, NLGI, and TERI projects. The three and nine months ended September 2002 results of operations include the Crockett Cogeneration, Entrade, Killingholme, Csepel, Hsin Yu, Bulo Bulo, McClain, NLGI, and TERI projects.

	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
		(In thousands)		
Operating revenue	$ 38,817	$ 224,075	$ 102,944	$ 629,344
Operating & other expenses	38,969	812,721	237,508	1,218,192
Pretax loss from operations of discontinued components	(152)	(588,646)	(134,564)	(588,848)
Loss from operations of discontinued components	(480)	(585,622)	(134,150)	(585,060)
Disposal of discontinued components gain (loss) — net of income taxes	(624)	(836)	188,104	(10,510)
Net income (loss) on discontinued operations	$ (1,104)	$ (586,458)	$ 53,954	$ (595,570)

The assets and liabilities of the discontinued operations are reported in the balance sheets as of September 30, 2003 as held for sale. The major classes of assets and liabilities held for sale by geographic area are presented in the following table. The North America segment includes the McClain project. The Asia Pacific segment includes the Hsin Yu project.

	Power Generation		
September 30, 2003	North America	Asia Pacific	Total
		(In thousands)	
Cash	$ 201	$ 653	$ 854
Restricted cash	1,821	444	2,265
Receivables, net	412	16,572	16,984
Inventory	2,109	2,581	4,690
Prepaids and deposits	462	7,894	8,356
Other current assets	731	1,962	2,693
Current assets — discontinued operations	$ 5,736	$ 30,106	$ 35,842
PP&E, net	$159,176	$ 41,301	$200,477
Other non-current assets	2,687	10,290	12,977
Non-current assets — discontinued operations	$161,863	$ 51,591	$213,454
Current portion of long-term debt	$ —	$ 86,546	$ 86,546
Accounts payable — trade	155	25,413	25,568
Other current liabilities	857	368	1,225
Current liabilities — discontinued operations	$ 1,012	$112,327	$113,339

September 30, 2003	Power Generation North America	Power Generation Asia Pacific	Power Generation Total
		(In thousands)	
Long-term debt	$ —	$ 3,883	$ 3,883
Deferred income tax	—	4,909	4,909
Payable to contractors	—	4,389	4,389
Other accrued liabilities	—	4,400	4,400
Other non-current liabilities	—	5,192	5,192
Non-current liabilities — discontinued operations	$ —	$22,773	$ 22,773
Financing debt — subject to compromise	$156,509	$ —	$156,509
Other liabilities — subject to compromise	2,601	—	2,601
Liabilities — discontinued operations — subject to compromise	$ 159,110	$ —	$ 159,110

The disclosure below has been updated to reflect discontinued components as of September 30, 2003. The North America segment includes the McClain project. The Europe segment includes the Killingholme projects. The Asia Pacific segment includes the Hsin Yu Project. The Alternative Energy segment includes the NLGI and TERI projects.

December 31, 2002	Power Generation North America	Power Generation Europe	Power Generation Asia Pacific	Power Generation Alt-Energy	Power Generation Total
			(In thousands)		
Cash	$ 3,111	$ 23,173	$ 736	$ 430	$ 27,450
Restricted cash	5,094	—	3	—	5,097
Receivables, net	7,857	19,869	3,315	269	31,310
Derivative instruments valuation	—	29,795	—	—	29,795
Other current assets	2,329	14,768	8,203	557	25,857
Current assets — discontinued operations	$ 18,391	$ 87,605	$ 12,257	$ 1,256	$ 119,509
PP&E, net	$265,236	$231,048	$ 43,496	$ 11,962	$ 551,742
Derivative instruments valuation	—	87,804	—	—	87,804
Other non-current assets	3,320	6,983	10,441	18,532	39,276
Non-current assets — discontinued operations	$268,556	$325,835	$ 53,937	$30,494	$678,822
Current portion of long-term debt	$157,288	$360,122	$ 85,534	$ 7,658	$ 610,602
Accounts payable — trade	5,362	35,310	15,457	859	56,988
Other current liabilities	6,426	16,054	596	3,798	26,874
Current liabilities — discontinued operations	$169,076	$411,486	$101,587	$ 12,315	$694,464
Long-term debt	$ —	$ —	$ 72	$ —	$ 72
Deferred income tax	(1)	123,632	4,364	(2,102)	125,893
Derivative instruments valuation	—	12,302	—	—	12,302
Other non-current liabilities	16	—	13,947	217	14,180
Non-current liabilities — discontinued operations	$ 15	$135,934	$ 18,383	$ (1,885)	$ 152,447

Bulo Bulo — In June 2002, NRG Energy began negotiations to sell its 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. NRG Energy accounted for the results of operations of Bulo Bulo as part of its power generation segment within the Other Americas region.

Crockett Cogeneration Project — In September 2002, NRG Energy announced that it had reached an agreement to sell its 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 NRG Energy 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. NRG Energy accounted for the results of operations of Crockett Cogeneration as part of its power generation segment within North America.

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

Killingholme — During third quarter 2002 NRG Energy recorded an impairment charge of $477.9 million. In January 2003, NRG Energy completed the sale of its interest in the Killingholme project to its lenders for a nominal value and forgiveness of outstanding debt with a carrying value of approximately $360.1 million at December 31, 2002. The sale of NRG Energy's interest in the Killingholme project and the release of debt obligations resulted in a gain on sale in the first quarter of 2003 of approximately $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. NRG Energy accounted for the results of operations of Killingholme as part of its power generation segment within Europe.

Hsin Yu — During the third quarter of 2002, NRG Energy committed to sell its ownership interest in Hsin Yu located in Taiwan and recorded an impairment charge of approximately $121.8 million for the project. NRG Energy owns 60% with one other party owning the remaining minority interest. NRG Energy was negotiating to sell its interest in the project to the minority owner for a nominal value plus assumption of its future funding obligations. As of July 4, 2003, the minority owners withdrew from the negotiation process. NRG Energy continues to pursue other sales alternatives. NRG Energy accounts for the results of operations of Hsin Yu as part of its power generation segment within Asia Pacific.

NLGI — During 2002, NRG Energy recorded an impairment charge of $12.4 million related to subsidiaries of NLGI, an indirect wholly owned subsidiary of NRG Energy. The charge was based on a revised project outlook. During the quarter ended March 31, 2003, NRG Energy recorded impairment charges of $23.6 million related to subsidiaries of NLGI and a charge of $14.5 million to write off its 50% investment in Minnesota Methane, LLC. Through April 30, 2003, NRG Energy and NLGI failed to make certain payments causing a default under NLGI's term loan agreements. In May 2003, the project lenders to the wholly-owned subsidiaries of NLGI and Minnesota Methane LLC foreclosed on NRG Energy's membership interest in the NLGI subsidiaries and NRG Energy's equity interest in Minnesota Methane LLC. There was no material gain or loss recognized as a result of the foreclosure.

NRG Energy may be contingently liable for up to approximately $50 million of future tax-related payments through 2007 to the owners of NLGI. NRG Energy recorded a Section 29 tax credit obligation of approximately $6.5 million in connection with the foreclosure that represents the amount owed by NRG Energy for the tax credits generated by NLGI prior to the change in ownership. Additional obligations do not exist until the Section 29 tax credits are generated from ongoing operations and the new project owner is unable to utilize such credits.

McClain — During second quarter of 2003, NRG reviewed the recoverability of its McClain assets pursuant to SFAS No. 144 and recorded an impairment charge of $101.8. In August 2003, NRG Energy announced that it had reached an agreement to sell its 77% interest in McClain Generating Station, a 520 MW combined-cycle, natural gas-fired facility located in Newcastle, Oklahoma to Oklahoma Gas & Electric Company. As part of the sales process, the project company NRG McClain LLC, filed for protection under Chapter 11 of the U.S. Bankruptcy Code. Upon completion, the sale will result in proceeds of approximately $160 million. No material gain or loss is expected on the sale.

TERI — During 2002, NRG Energy recorded an impairment charge of $11.7 million based on a revised project outlook. In September 2003, NRG Energy completed the sale of its controlling interest in 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 and an additional net loss of approximately $0.6 million at closing.

4. Restructuring and Impairment Charges and Legal Settlement

NRG Energy reviews the recoverability of its long-lived assets in accordance with the guidelines of SFAS No. 144. As a result of this review, NRG Energy recorded impairment charges of $6.0 million and $229.6 million for the three and nine months ended September 30, 2003, respectively and $2.5 billion for the three and nine months ended September 30, 2002, as shown in the table below.

To determine whether an asset was impaired, NRG Energy 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 NRG Energy’s 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 NRG Energy’s 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.

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

	Three Months Ended September 30, 2003 Restated	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003 Restated	Nine Months Ended September 30, 2002
		(In thousands)		
Impairment charges	$ 5,958	$ 2,470,656	$ 229,564	$ 2,496,001
Legal settlement	396,000	—	396,000	—
Reorganization items	20,698	—	27,032	—
*Restructuring charges	294	17,090	68,455	37,669
Total	$ 422,950	$ 2,487,746	$ 721,051	$ 2,533,670

* Includes Restructuring Professional Fees and Expense.

Impairment Charges

Impairment charges included the following for the three months ended September 30, 2003:

Project Name	Project Status	Pre-tax Charge	Fair Value Basis
		(In thousands)	
Arthur Kill Power, LLC	Terminated	$ 9,049	Projected cash flows
Langage (UK)	Sold	(3,091)	Realized gain upon sale
Total Impairment Charges		$ 5,958	

Impairment charges included the following for the nine months ended September 30, 2003:

Project Name	Project Status	Pre-tax Charge	Fair Value Basis
		(In thousands)	
Devon Power LLC	Operating at a loss	$ 64,198	Projected cash flows
Middletown Power LLC	Operating at a loss	157,323	Projected cash flows
Arthur Kill Power, LLC	Terminated	9,049	Projected cash flows
Langage (UK)	Terminated	(3,091)	Realized gain
Other	Terminated	2,085	
Total Impairment Charges		$229,564	

Impairment charges included the following for the three months ended September 30, 2002:

Project Name	Project Status	Pre-tax Charge	Fair Value Basis
		(In thousands)	
Nelson	Terminated	$ 619,768	Similar asset prices
Pike	Terminated in bankruptcy	528,654	Similar asset prices
Bourbonnais	Terminated	269,649	Similar asset prices
Meriden	On hold	180,318	Similar asset prices
Brazos Valley	Foreclosure	102,900	Projected cash flows
Kendall, Batesville & other expansion projects	Terminated	147,053	Similar asset prices
Langage (UK)	Terminated	43,828	Estimated market price
Turbines & other costs	Construction on hold	308,651	Similar asset prices
Audrain	Operating at a loss	66,142	Projected cash flows
Bayou Cove	Operating at a loss	126,528	Projected cash flows
Somerset	Operating at a loss	49,289	Projected cash flows
Other	Operating at a loss	27,876	Projected cash flows
Total Impairment Charges		$2,470,656	

Impairment charges included the following for the nine months ended September 30, 2002:

Project Name	Project Status	Pre-tax Charge	Fair Value Basis
		(In thousands)	
Nelson	Terminated	$ 619,768	Similar asset prices
Pike	Terminated	528,654	Similar asset prices
Bourbonnais	Terminated	269,649	Similar asset prices
Meriden	On hold	180,318	Similar asset prices
Brazos Valley	Foreclosure in process	102,900	Projected cash flows
Kendall, Batesville & other expansion projects	Terminated	147,053	Similar asset prices
Langage (UK)	Terminated	43,828	Estimated market price
Turbines & other costs	Construction on hold	308,651	Similar asset prices
Audrain	Operating at a loss	66,142	Projected cash flows
Bayou Cove	Operating at a loss	126,528	Projected cash flow
Somerset	Operating at a loss	49,289	Projected cash flow
Other	Operating at a loss	53,221	Projected cash flows
Total Impairment Charges		$2,496,001	

Connecticut Facilities — NRG Energy reviewed cash flow models for its Connecticut generating facilities at December 31, 2002. No impairment was required based on the pricing and cost recovery assumptions at December 31, 2002. On February 26, 2003 NRG Energy filed a proposed cost of service agreement for the following Connecticut facilities with the Federal Energy Regulatory Commission (FERC) Devon 11-14, Middletown station, Montville station, Norwalk Harbor station. On April 25, 2003, the FERC issued an order that rejected NRG Energy’s proposed fixed monthly charges, citing certain policy determinations regarding cost-of-service agreements. FERC instead directed NRG Energy to recover its fixed and variable costs under interim bidding rules for generators located in constrained areas, the so-called Peaking Unit Safe Harbor (PUSH) mechanism. The PUSH bidding rules would apply to all of NRG Energy's Connecticut facilities that filed the proposed cost of service agreements, with the exception of Middletown Units 2 and 3, until June 1, 2004. The following quick start facilities, located in Connecticut also have submitted PUSH bids that have been approved by FERC: Cos Cob, Franklin Drive, Branford and Torrington. FERC also ordered that the regional power agencies overseeing the energy markets in Connecticut, the Independent System Operator for New England (ISO-NE) and the New England Power Pool (NEPOOL), modify the New England market rules to establish and implement locational capacity or deliverability requirements no later than June 1, 2004. In late May and June 2003, ISO-NE revised its market pricing rules to facilitate FERC's mandated PUSH mechanism, but has not yet proposed the market modifications required to implement locational capacity or deliverability requirements. In June 2003 NRG Energy filed for rehearing of several elements of FERC's April 25, 2003 order. In response, on July 25, 2003, FERC re-affirmed the PUSH interim pricing mechanism.

The existing RMR between ISO-NE and NRG Energy covering Devon 7 and 8 terminated on September 30, 2003. On October 2, 2003, NRG filed to extend the existing RMR agreements. A number of protests have been filed and FERC has yet to act on the request to extend the agreements.

As a result of these regulatory developments and changing circumstances in the second quarter of 2003, NRG Energy updated the facilities' cash flow models to incorporate changes to reflect the impact of the April 25, 2003 FERC's orders on PUSH pricing, the pending termination of the RMR, 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 NRG Energy recorded a $64.2 million and $157.3 million impairment at Devon Power LLC and Middletown Power LLC, respectively. NRG Energy accounts for the results of operations of the Connecticut Facilities as part of its power generation segment within North America.

Langage (UK) — During the third quarter of 2002, NRG Energy reviewed the recoverability of its Langage assets pursuant to SFAS No. 144 and recorded a charge of $43.8 million. In August 2003 NRG Energy closed on the sale of Langage to Carlton Power Limited resulting in net cash proceeds of approximately $1.0 million and a net gain of approximately $3.1 million.

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

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

Turbines — In October 2003, NRG Energy closed on the sale of three turbines and related equipment. During second quarter of 2002, NRG Energy recorded an impairment charge of $52.8 million related to these turbines. The sale resulted in net cash proceeds of $70.7 million and a gain of approximately $21.9 million.

Restructuring Charges

NRG Energy incurred total restructuring charges of approximately $0.3 million and $68.5 million for the three and nine months ended September 30, 2003. NRG Energy incurred total restructuring costs of approximately $17.1 million and $37.7 million for the three and nine months ended September 30, 2002. These charges are discussed in the following paragraphs.

NRG Energy incurred approximately $20.7 million and $27.0 million of reorganization items related to professional and advisors fees for the three and nine months ended September 30, 2003, respectively.

Severance accruals have been recorded based on certain contractual agreements and benefits offered by NRG Energy to its employees. Severance costs have been recognized for only those employees who have been terminated as of September 30, 2003. The severance accrual was $1.9 million and $18.4 million as of September 30, 2003 and December 31, 2002, respectively. During the second quarter of 2003, a settlement agreement was reached with former NRG Energy executives resulting in a lower severance cost than previously recorded. As a result, approximately $8.4 million was reversed out of the severance accrual into income during the second quarter of 2003.

Brazos Valley — In January 2003, the project lenders foreclosed on NRG Energy's ownership interests in NRG Brazos Valley GP, LLC, NRG Brazos Valley LP, LLC, NRG Brazos Valley Technology LP, LLC and NRGBrazos Valley Energy, LP, and the lenders thereby acquired all of the assets of the Brazos Valley project, a 633 MW project under construction near Houston, TX. NRG Energy agreed to the consensual foreclosure of the companies including a possible obligation of approximately $75.0 million under a contingent equity agreement if the project assets were not sufficient to cover the outstanding obligations to the lender. As of December 31, 2002, NRG Energy recorded approximately $24.0 million for the potential obligation to infuse additional amounts of capital to fund a debt service reserve account (approximately $10.0 million) and the potential obligation to satisfy a contingent equity agreement. The consensual foreclosure in the first quarter of 2003 resulted in a pre-tax gain on sale of approximately $20.0 million. This gain resulted from the debt extinguishment. The gain was offset in full by the recognition of an additional $20.0 million obligation to satisfy the contingent equity agreement, resulting in a contingent equity total obligation recorded of approximately $34.0 million as of March 31, 2003. In June 2003, the lenders entered into a sales agreement whereby they agreed to sell the Brazos Valley project to a third party for a lower sale price then originally estimated. As a result of the lower sales price, in the second quarter of 2003, NRG Energy recorded an additional $42.0 million of contingent equity obligation, which is included in restructuring charges. As of September 30, 2003, approximately $76.0 million of contingent equity obligation was recorded.

Legal Settlement

During the third quarter of 2003, NRG Energy recorded $396.0 million in connection with the resolution of the FirstEnergy Arbitration Claim. As a result of this resolution, FirstEnergy will retain ownership of the Lake Plant Assets and will receive an allowed general unsecured claim of $396 million under NRG Energy's Plan of Reorganization submitted to the Bankruptcy Court. In accordance with SOP 90-7, this amount is recorded on the balance sheet as a prepetition liability.

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

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

	(Income)/Loss Three Months Ended September 30, 2003	(Income)/Loss Three Months Ended September 30, 2002	(Income)/Loss Nine Months Ended September 30, 2003	(Income)/Loss Nine Months Ended September 30, 2002
	(In thousands)			
NEO Corporation — Minnesota Methane	$ —	$ —	$ 12,257	$ 5,678
Kondapalli	—	—	(519)	—
ECKG	—	—	(2,869)	—
Loy Yang	—	53,590	139,972	53,590
Mustang	(12,310)		(12,124)	
Energy Development Limited (EDL)		14,287		14,287
Sabine River Works		49,392		49,392
Mt. Poso		600		600
Collinsville Power Station	—	—	—	4,168
Total write downs and (gains) losses of equity method investments	$ (12,310)	$ 117,869	$ 136,717	$ 127,715

NEO Corporation — Minnesota Methane — NRG Energy recorded an impairment charge of $5.6 million during the second quarter of 2002 to write-down its 50% investment in Minnesota Methane. NRG Energy recorded an additional impairment charge of $14.5 million during the first quarter of 2003. These charges were related to revised project outlook and management's belief that the decline in fair value was other than temporary. Through April 30, 2003, NRG Energy and NEO Landfill Gas, Inc. failed to make certain payments causing a default under NEO Landfill Gas, Inc.'s term loan agreements. In May 2003, the project lenders to the wholly-owned subsidiaries of NEO Landfill Gas, Inc. and Minnesota Methane LLC foreclosed on NRG Energy's membership interest in the NEO Landfill Gas Inc. subsidiaries and NRG Energy's equity interest in Minnesota Methane LLC. Upon completion of the foreclosure, NRG Energy recorded a gain of $2.2 million. This gain resulted from the release of certain obligations. NRG Energy accounts for the results of operations of NEO Corporation — Minnesota Methane as part of its power generation segment within Alternative Energy.

Kondapalli — On January 30, 2003, NRG Energy signed a sale agreement with the Genting Group of Malaysia (Genting) to sell NRG Energy's 30% interest in Lanco Kondapalli Power Pvt Ltd (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, NRG Energy wrote down its investment in Kondapalli by $1.3 million due to developments related to the sale that indicated an impairment of its book value that was considered to be other than temporary. The sale closed on May 30, 2003 resulting in net cash proceeds of approximately $24 million and a gain of approximately $1.8 million. The gain resulted from incurring lower selling costs then estimated as part of the first quarter impairment. NRG Energy accounted for the results of operations of Kondapalli as part of its power generation segment within the Asia Pacific Region.

ECKG — In September 2002, NRG Energy announced that it had reached agreement to sell its 44.5% interest in the ECKG power station in connection with its Csepel power generating facilities, and its interest in Entrade, an electricity trading business, to Atel, an independent energy group headquartered in Switzerland. The transaction closed in January 2003 and resulted in cash proceeds of $65.3 million and a net loss of less than $1.0 million. In accordance with the purchase agreement, NRG Energy was to receive additional consideration if Atel purchased shares held by NRG Energy's partner. During the second quarter of 2003, NRG Energy received approximately $3.7 million of additional consideration. NRG Energy accounted for the results of operations of its investment in ECKG as part of its power generation segment within the Europe Region.

Loy Yang — Based on a third party market valuation and bids received in response to marketing Loy Yang for possible sale, NRG Energy recorded a write down of its investment of approximately $111.4 million during 2002 ($53.6 during the third quarter and an additional $57.8 million during the fourth quarter). This write-down reflected management's belief that the decline in fair value of the investment was other than temporary. Accumulated other comprehensive loss at December 31, 2002 included foreign currency translation losses of approximately $76.7 million related to Loy Yang. The foreign currency translation losses were to remain as a component of accumulated other comprehensive loss until completion of the sale as required by FASB Statement No. 52 *"Foreign Currency Translation"* (FASB No. 52).

In May 2003, NRG Energy and it partners entered into negotiations that culminated in the completion of a Share Purchase Agreement to sell 100% of the Loy Yang project. Completion of the sale is subject to various conditions. Upon completion, the sale will result in proceeds of approximately $25.0 million to $31.0 million to NRG Energy. Consequently, NRG Energy recorded an additional impairment charge of approximately $140.0 million during the quarter ended June 30, 2003, which includes a charge of approximately $61.0 million of foreign currency translation losses related to the investment in Loy Yang in accordance with EITF Issue No 01-05 *"Application of FASB Statement No. 52 to an Investment Being Evaluated for Impairment that will be Disposed of."* In accordance with FASB No. 52, accumulated other comprehensive loss at June 30, 2003 included foreign currency translation losses of approximately $61.0 million related to Loy Yang. NRG Energy accounts for the results of operations of its investment in Loy Yang as part of its power generation segment within the Asia Pacific region.

Mustang Station — On July 7, 2003, NRG Energy completed the sale of its 50% interest in Mustang Station, a 483 MW 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, NRG Energy announced it had completed the sale of its ownership interests in an Australian energy company, Energy Development Limited (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, NRG Energy received proceeds of $78.5 million (AUS), or approximately $43.9 million (U.S.), in exchange for its ownership interest in EDL with the closing of the transaction. During the third quarter of 2002, NRG Energy recorded a write-down of the investment of approximately $14.3 million to write down the carrying value of its equity investment due to the pending sale. NRG Energy accounted for the results of operations of its investment in EDL as part of its power generation segment within the Asia Pacific region.

Sabine River — In September 2002, NRG Energy agreed to transfer its indirect 50% interest in SRW Cogeneration LP (SRW) to its partner in SRW, Conoco, Inc. in consideration for Conoco's agreement to terminate or assume all of the obligations of NRG Energy in relation to SRW. SRW owns a cogeneration facility in Orange County, Texas. NRG Energy recorded a charge of approximately $49.4 million during the quarter ended September 30, 2002 to write down the carrying value of its investment due to the pending sale. The transaction closed on November 5, 2002. NRG Energy accounted for the results of operations of its investment in SRW as part of its power generation segment within North America.

Mt. Poso — In September 2002, NRG Energy agreed to sell its 39.5% indirect partnership interest in the Mt. Poso Cogeneration Company, a California limited partnership (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. NRG Energy accounted for the results of operations of its investment in Mt. Poso as part of its power generation segment within North America.

Collinsville Power Station — Based on third party market valuation and bids received in response to marketing the investment for possible sale, NRG Energy recorded a write down of its investment of approximately $4.1 million during the second quarter of 2002. In August 2002, NRG Energy announced that it had completed the sale of its 50% interest in the 192 MW Collinsville Power Station in Australia, to its partner, a subsidiary of Transfield Services Limited for $8.6 million (AUS), or approximately $4.8 million (USD). NRG Energy's ultimate loss on the sale of Collinsville Power Station was approximately $3.6 million. NRG Energy accounted for the results of operations of its investment in Collinsville Power Station as part of its power generation segment within the Asia Pacific region.

6. Income Taxes

The income tax provision for the nine months ended September 30, 2003 has been recorded on the basis that NRG Energy and each of its subsidiaries will file separate federal income tax returns. The income tax provision for the nine months ended September 30, 2002 has been recorded on the basis that NRG Energy and its subsidiaries filed a consolidated federal income tax return for the period January 1 through June 3, 2002, and NRG Energy and each of its subsidiaries filed separate federal income tax returns for the remainder of 2002.

Following Xcel Energy's acquisition of NRG Energy's public shares on June 3, 2002, Xcel Energy decided not to include NRG Energy in its consolidated federal income tax return. Consequently, NRG Energy and each of its subsidiaries are required to file separate federal income tax returns.

For the nine months ended September 30, 2003 income tax expense on continuing operations was $44.9 million compared to a tax benefit of $150.8 million for the same period in 2002. The tax expense for the nine months ended September 30, 2003 includes $36.1 million and $8.8 million of U.S. and foreign taxes, respectively. During 2003, an additional valuation allowance of $33 million was recorded against the deferred tax assets of NRG West Coast as a result of its conversion from a corporation to a disregarded entity for federal income tax purposes. Subsequent to the conversion, NRG West Coast will no longer be taxed as an entity separate from NRG Energy. This conversion was completed to reduce current tax payments for 2003.

The tax benefit for the nine months ended September 30, 2002 resulted from the recognition of deferred tax assets related to asset impairments recorded for financial reporting purposes. It is uncertain if NRG Energy will be able to fully realize tax benefits on net operating losses and deferred tax assets. Consequently, a valuation allowance was recorded against the deferred tax assets for net operating loss carryforwards and for other deferred tax assets in excess of previously-recognized deferred tax liabilities.

The effective income tax rate for the periods ended September 30, 2003 and September 30, 2002 differs from the statutory federal income tax rate of 35% primarily due to limitation on tax benefits and lower foreign statutory rates.

As of September 30, 2003, NRG Energy provided a valuation allowance of approximately $701.6 million to account for potential limitations on utilization of U.S. and Foreign net operating loss carryforwards compared to a valuation allowance of $281.8 for the same period in 2002. The net operating loss carryforwards expire between 2003 and 2021. NRG Energy also provided a valuation allowance for other U.S.

and Foreign deferred income tax assets of approximately $846.7 million for the period ending September 30, 2003 compared to $402.7 million for the same period in 2002.

7. Summarized Financial Information of Affiliates

NRG Energy has a 50% interest in one company (West Coast Power LLC) that was considered significant, as defined by applicable SEC regulations, and accounts for its investment using the equity method.

West Coast Power LLC Summarized Financial Information

The following table summarizes financial information for West Coast Power LLC, including interests owned by NRG Energy and other parties for the periods shown below:

Results of Operations

	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	For the Nine Months Ended September 30, 2003	For the Nine Months Ended September 30, 2002
		(In millions)		
Operating revenues	$ 308	$ 288	$ 834	$ 688
Operating income	$ 67	$ 38	$ 204	$ 119
Net income (pre-tax)	$ 74	$ 24	$ 205	$ 98

Financial Position

	September 30, 2003	December 31, 2002
	(In millions)	
Current assets	$ 236	$ 255
Other assets	497	532
Total assets	$ 733	$ 787
Current liabilities	$ 54	$ 112
Other liabilities	—	34
Equity	679	641
Total liabilities and equity	$ 733	$ 787

8. Short Term Debt and Long Term Debt

As of September 30, 2003, NRG Energy has failed to make scheduled payments of interest and/or principal on approximately $4.0 billion of its recourse debt and is in default under the related debt instruments. These missed payments also have resulted in cross-defaults of numerous other non-recourse and limited recourse debt instruments of NRG Energy and its subsidiaries. In addition to the missed debt payments, a significant amount of NRG Energy's debt and other obligations contain terms, which require that they be supported with letters of credit or cash collateral following a ratings downgrade. As a result of the downgrades that NRG Energy experienced in 2002, NRG Energy estimates that it is in default on approximately $1.2 billion of cash collateral obligations principally to fund a $842.5 million guarantee associated with its construction revolver financing facility, to fund debt service reserves and other guarantees related to NRG Energy projects, and to fund trading operations.

Absent an agreement on a comprehensive restructuring plan, NRG Energy will remain in default under its debt and other obligations until its restructuring plan is approved and emerges from bankruptcy, because it does not have sufficient funds to meet such debt and other obligations. There can be no assurance that NRG Energy's creditors ultimately will accept the reorganization plan that NRG Energy will submitted for approval as part of its Chapter 11 reorganization. See Note 1 for discussion of NRG Energy's restructuring efforts.

As a result of NRG Energy's bankruptcy filing, NRG Energy has classified its corporate level debt as a prepetition obligation subject to compromise and has ceased recording accrued interest as it is not probable of being paid. The contractual interest requirement for such corporate level debt is $78.4 million and $118.6 million for the three months ended September 30, 2003, and for the period May 14, 2003 (the date of the bankruptcy petition) to September 30, 2003, respectively.

NRG Energy Bank Debt

NRG Energy has a $1.0 billion unsecured 364-day revolving line of credit. As of September 30, 2003 the outstanding balance was $1.0 billion, unchanged from the December 31, 2002 balance. As of September 30, 2003, the interest rate on such outstanding advances was 7.0% plus a 0.5% facility fee per year. The credit facility matured fully drawn on March 7, 2003. NRG Energy failed to make a first-quarter payment of $19.3 million, failed to make a second quarter payment of $18.0 million and failed to make a third quarter payment of $18.9 million relating to interest and fees on the facility.

As a result of NRG Energy's bankruptcy filing, NRG Energy has classified the revolving line of credit as a prepetition obligation subject to compromise and has ceased recording accrued interest, as it is not probable of being paid. Contractual interest requirement for the revolving line of credit is $18.9 million and $28.6 million for the three months ended September 30, 2003, and for the period May 14, 2003 (the date of the bankruptcy petition) to September 30, 2003, respectively.

NRG Energy has in place a syndicated letter of credit facility that contains terms, conditions and covenants that are substantially the same as those in NRG Energy's $1.0 billion 364-day revolving line of credit. The original amount of the letter of credit facility was $125 million, but the amount has been reduced to the amount outstanding. NRG Energy had $103.0 million and $110.7 million in outstanding letters of credit under the facility as of September 30, 2003 and December 31, 2002, respectively. Of the $103.0 million outstanding at September 30, 2003, $88.8 million was in the form of standby letters of credit, and $14.2 million was drawn.

Debtor-in-Possession Facility

NRG Energy and certain of its subsidiaries have negotiated a Senior Secured, Super-Priority Debtor-in-Possession Credit Agreement (the DIP Agreement) with General Electric Capital Corporation (GECC), which was executed following the filing of the petition in NRG Energy's Chapter 11 bankruptcy case. Under the DIP Agreement, GECC has agreed to make up to $250 million (the DIP Facility) available for working capital and general corporate needs of the debtors that comprise NRG's Northeast generating facilities (the DIP Borrowers). The DIP Facility is secured by a first priority lien on substantially all of the assets of and equity interest in the DIP Borrowers, plus the assets of Power Marketing, Inc. that relate to the revenues of the DIP Borrowers.

The DIP Facility bears an interest rate of 2.00% over the prime rate or 3.50% over the LIBOR rate and is currently set to expire on May 13, 2004. NRG Energy does not currently anticipate that it will seek to extend the DIP Facility beyond May 13, 2004. However, should the DIP Facility be extended for more than one year, approval of such financing by New York Public Service Commission will be required as certain

NRG Energy assets securing the loan are located in New York. Should such approval be necessary, NRG Energy intends to make a timely application for the approval.

The amount available under the DIP Facility may vary from time to time, depending on valuations of the collateral securing the DIP Facility and GECC's right to set aside certain reserves. The DIP Facility currently permits the DIP Borrowers to borrow up to $210 million. The total availability may increase to $250 million upon the occurrence of certain subsequent events. A final order approving the DIP Facility was entered by the Bankruptcy Court on July 24, 2003. Such order provides, among other things, that the borrowers may not use DIP funds or cash collateral to make disbursements to, or for the benefit of the Connecticut Light and Power Company, unless further agreed to by GECC, the DIP lender, the Official Committee of Unsecured Creditors of NRG Energy, Inc. et al. and the informal committee of holders of the three series of Senior Secured Bonds issued by NRG Northeast Generating LLC, or further order of the Bankruptcy Court.

As of September 30, 2003, there was no amount outstanding under the DIP Facility. As of September 30, 2003, under the DIP Facility, the Company paid a facility fee of approximately $0.9 million. In addition, the Company pays a commitment fee based on utilization of the facility of between 0.5% and 1.0% of the unused commitments of $210.0 million.

The DIP Facility contains covenants which restrict mergers and acquisitions, the incurrence of additional debt, the creation of liens, sale of stock and assets, sale-leasebacks, cancellation of indebtedness constituting collateral or subordinated debt, restricted payments, speculative transactions, maximum annual capital expenditures and minimum quarterly earnings as outlined in the DIP Agreement.

In addition, the DIP Facility includes the following reporting covenants: provide monthly financial statements and operating reports within 30 days, provide quarterly financial statements and operating reports within 45 days, provide annual audited financial statements within 90 days of the end of the Company's fiscal year; provide an operating plan within 30 days of the fiscal year end, provide management letter and notices described in the DIP Agreement when available or as reasonably requested by the DIP Lenders.

Senior Notes

Between 1996 and 2001, NRG Energy issued the following series of senior notes: $125 million of 7.625% senior notes due February 1, 2006; $250 million of 7.5% senior notes due June 15, 2007; $300 million of 7.5% senior notes due June 1, 2009; $350 million of 8.25% senior notes due September 15, 2010; $350 million of 7.75% senior notes due April 1, 2011; $500 million of 8.625% senior notes due April 1, 2031; $340 million of 6.75% senior notes due July 15, 2006; and £160 million of 7.97% senior reset notes due March 15, 2020. The entire principal amount issued for each note was outstanding as of September 30, 2003 and December 31, 2002, respectively.

During the third quarter of 2003, NRG failed to make a $11.5 million interest payment due on July 15, 2003 on $340 million of 6.75% senior notes maturing July 15, 2006; a $4.8 million interest payment due on August 1, 2003, on $125 million of 7.625% senior notes maturing on February 1, 2006; a $4.7 million interest payment due August 16, 2003 on $287.5 million of 6.5% senior debentures maturing on May 16, 2004; a $10.9 million interest payment due on September 15, 2003, on £160 million of 7.97% Remarketable or Redeemable securities maturing March 15, 2005; and a $14.4 million interest payment due on September 15, 2003 on $350 million 8.250% senior notes maturing on September 15, 2010.

As a result of NRG Energy's bankruptcy filing, NRG Energy has classified the senior notes as a prepetition obligation subject to compromise and has ceased recording accrued interest, as it is not probable of being paid. The contractual interest requirements for the Senior notes is $49.3 million and $74.4 million for the three months ended September 30, 2003, and for the period May 14, 2003 (the date of the bankruptcy petition) to September 30, 2003, respectively.

Remarketable or Redeemable Securities

On November 8, 1999, NRG Energy issued $240 million of 8.0% Remarketable or Redeemable Securities due November 1, 2013. The outstanding principal amount was $240 million as of both September 30, 2003 and December 31, 2002.

As a result of NRG Energy's bankruptcy filing, NRG Energy has classified the remarketable or redeemable securities as a prepetition obligation subject to compromise and has ceased recording accrued interest, as it is not probable of being paid. The contractual interest requirements for the remarketable or redeemable securities is $4.8 million and $7.4 million for the three months ended September 30, 2003, and for the period May 14, 2003 (the date of the bankruptcy petition) to September 30, 2003.

Equity Units

On March 13, 2001, NRG Energy completed the sale of 11.5 million equity units (symbol: NRZ) for an initial price of $25 per unit. Each equity unit consisted of a corporate unit comprising a $25 principal amount of NRG Energy's senior debentures and an obligation to acquire shares of Xcel Energy common stock. When NRG Energy filed for bankruptcy, the obligation to purchase shares of Xcel Energy stock terminated.

On May 15, 2003, NRG Energy announced that it had been notified that the New York Stock Exchange (NYSE) has suspended trading in NRG Energy's corporate units that trade under the ticker symbol NRZ and that an application to the Securities and Exchange Commission to delist the Units is pending the completion of applicable procedures, including appeal by NRG Energy of the NYSE staff's decision. NRG Energy does not plan to make such an appeal. The NYSE took this action following NRG Energy's announcement that it and certain of its affiliates had filed voluntary positions for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

As of both September 30, 2003 and December 31, 2002, the outstanding principal amount of the senior debentures was $287.5 million. Pursuant to an order of the Bankruptcy Court dated July 16, 2003, NRG Energy was directed to instruct the collateral agent to release the debentures pledged in connection with the NRZs.

As a result of NRG Energy's bankruptcy filing, NRG Energy has classified the Equity Units outstanding amount as a prepetition obligation subject to compromise and has ceased recording accrued interest, as it is not probable of being paid. The contractual interest requirement for the Equity Units is $4.7 million and $7.2 million for the three months ended September 30, 2003, and for the period May 14, 2003 (the date of the bankruptcy petition) to September 30, 2003, respectively.

Project Debt Defaults

In May 2001, NRG Energy's indirect wholly-owned subsidiary, NRG Finance Company I LLC, entered into a $2 billion revolving credit facility. As of September 30, 2003, the outstanding amount under this facility was $1.1 billion, unchanged from December 31, 2002. As of September 30, 2003, the interest rate on such outstanding advances was 6.85% per year.

As a result of NRG Energy's bankruptcy filing, NRG Energy has classified the revolving credit facility as a prepetition obligation subject to compromise and has ceased recording accrued interest, as it is not probable of being paid. Contractual interest requirement for the revolving credit facility is $18.9 million and $28.6 million for the three months ended September 30, 2003, and for the period May 14, 2003 (the date of the bankruptcy petition) to September 30, 2003, respectively.

As part of NRG Energy's acquisition of the LS Power assets in January 2001, NRG Energy, through its indirect wholly owned subsidiary, LSP Kendall Energy LLC, acquired a $554.2 million credit facility. The facility is non-recourse to NRG Energy and consists of a construction and term loan, working capital and letter of credit facility. As of September 30, 2003 and December 31, 2002, there were borrowings totaling approximately $489.2 million and $495.8 million, respectively, outstanding. The facility's interest rate was 2.49% as of September 30, 2003.

On November 28, 2001, NRG McClain LLC entered into a credit agreement with Westdeutsche Landesbank Girozentrale, New York Branch and various other lending institutions for a $181.0 million secured term loan (the McClain Secured Term Loan) and an $8.0 million working capital facility. As of September 30, 2003 and December 31, 2002, the outstanding amount under this facility was $156.5 million and $157.3 million, respectively. As of September 30, 2003, the interest rate on such outstanding borrowings was 4.5%. On August 19, 2003, NRG announced an agreement to sell its interest in McClain to Oklahoma Gas and Electric Company.

In June 2002, NRG Peaker Finance Company LLC (NRG Peaker), an indirect wholly owned subsidiary of NRG Energy, completed the issuance of $325 million of Series A Floating Rate Senior Secured Bonds due 2019. The bonds bear interest at a floating rate equal to three-months USD-LIBOR — BBA plus 1.07%. NRG Peaker entered into an interest rate swap by which NRG Peaker pays a fixed rate of 6.667% through the final maturity of the bonds. As of September 30, 2003 the outstanding amount on this facility was $319.4 million, unchanged from December 31, 2002. On May 13, 2003, XL Capital Assurance, as controlling party, accelerated the debt issued by NRG Peaker, rendering the debt immediately due and payable.

On September 18, 2003, NRG Energy, NRG Peaker and certain other affiliated entities entered into a Restructuring Agreement with XL Capital Assurance providing, among other things, NRG Energy will post a Letter of Credit for the benefit of the secured parties in the peaker financing in an amount equal to the termination payment (plus interest) under NRG Energy's contingent guarantee multiplied by the percentage recovery for such secured parties' creditor class in the NRG Energy bankruptcy. The Letter of Credit will be drawn down to pay the principal and interest payments on the bonds to the extent net revenues from the peaker projects are insufficient to make such payments. Pursuant to the terms of the Restructuring Agreement, all defaults arising under the original financing shall either be cured or waived by XL Capital Assurance and each of the parties to the Restructuring Agreement will provide mutual releases. The Restructuring Agreement will allow the peaker projects to continue their operations without interruption.

9. Guarantees

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

NRG Energy is directly liable for the obligations of certain of its project affiliates and other subsidiaries pursuant to guarantees relating to certain of their indebtedness, equity and operating obligations. As of September 30, 2003, NRG Energy had extended approximately 39 guarantees, which are listed below. For 25 of these 39 guarantees, the maximum exposure can be quantified, and totals approximately $800 million. The maximum exposure under the remaining 14 guarantees is indeterminate.

In connection with the purchase and sale of fuel, emission credits and power generation products to and from third parties with respect to the operation of some of NRG Energy's generation facilities in the United States, NRG Energy may be required to guarantee a portion of the obligations of certain of its subsidiaries. For these purposes, NRG Energy, Inc. guarantees the obligations of its wholly owned subsidiary, NRG Power Marketing, Inc (NRG PMI). As of September 30, 2003, NRG Energy guarantees of NRG PMI obligations to approximately 23 counter-parties totaled approximately $154 million.

As a result of the downgrades of NRG Energy's unsecured debt ratings, NRG Energy has been required to post cash collateral with respect to 11 separate transactions. The cash collateral requirement for the 11 transactions totals approximately $1.2 billion. NRG Energy's cash collateral obligations are listed below. As of September 30, 2003, NRG Energy has been unable to provide any of the required cash collateral.

NRG Energy's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries are summarized as follows:

NRG Energy, Inc.'s Guarantee and Cash Collateral Obligations as of September 30, 2003

(includes only quantifiable amounts)

Description	September 30, 2003
	(In thousands)
Guarantees of subsidiaries	$ 799,636
Guarantees of NRG PMI obligations	154,295
Cash collateral calls	1,177,545
Total guarantees	$ 2,131,476

As of September 30, 2003, the nature and details of NRG Energy's subsidiary guarantees, excluding guarantees of NRG PMI obligations and cash collateral calls were as follows:

NRG Energy Inc. Guarantee Obligations as of September 30, 2003

Project/Subsidiary	Guarantee/Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
	(In thousands)			
Able Acquisition Co. (First Energy Acquisition)	Indeterminate	Performance Under Asset Sales Agreement	None stated	Non-performance
Astoria/ Arthur Kill	Indeterminate	Performance Under Swaption Agreement	None stated	Non-performance
Audrain	Indeterminate	Payment Obligations of Municipal Bonds	December 1, 2023	Non-payment
Bourbonnais/ Hardee	$44,125	Turbine Purchase Obligation	October 1, 2007	Non-performance
Brazos Valley	$7,600	Interconnection Agreement Obligation	Upon Completion of the Interconnect	Non-performance of Subsidiary Obligations
Bulo Bulo	$8,000	Obligations Under Share Purchase Agreement	December 1, 2007	Non-performance of Subsidiary Obligations
Cahua S.A.	$5,258	Obligations Under Three Separate Credit Agreement	Undetermined	Default Under Terms of Credit Agreement
CL&P SOS	$37,000	Obligation Under Standard Offer Service Agreement	December 2003	Non-performance

Project/Subsidiary	Guarantee/Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
	(In thousands)			
Csepel	$50,000	Obligations Under Share Purchase Agreement	December 13, 2007	Non-performance of Subsidiary Obligations
ECKG	$22,250	Obligations Under Share Purchase Agreement	December 13, 2007	Non-performance of Subsidiary Obligations
Elk River/ Newport	$25,790	Obligation Under Bond Arrangement with NSP	Undetermined	Non-payment of Affiliate Obligation
Enfield	$3,751	Guarantee of Debt Service Reserve Amount	December 13, 2007	Non-performance of Subsidiary Obligations
Entrade	$8,000	Obligations Under Share Purchase Agreement	December 13, 2007	Non-performance of Subsidiary Obligations
Flinders	$8,257	Fund Superannuation (pension) reserve	September 8, 2012	Credit Agreement default
Flinders	$47,691	Debt service reserve guarantee	September 8, 2012	Credit Agreement default
Flinders	$51,098	Plant Removal and Site Remediation Obligation	Undetermined, at end of site lease	Non-performance
Flinders	$50,144	Guarantee of Employee Separation Benefits	None stated	Non-payment
Flinders (Flinders Osborne Trading)	$173,422	Guarantee of Obligation to Purchase Gas	None stated	Non-payment
Flinders (Flinders Osborne Trading)	Indeterminate	Indemnification of Government Entity for Payment for Power and Fuel	Fourth Quarter 2018	Non-payment
Gladstone	$21,923	Payment of Penalties in the Event of an Extraordinary Operational Breach	None stated	Non-performance
Gladstone	Indeterminate	Obligations Under Credit Agreement	March 31, 2009	Non-performance
Hsin Yu	$34,460	Obligations Under Share Purchase Agreement	None stated	Non-performance
Ilion	$13,200	Lease Payments Guarantees and Indemnifications Associated with Purchase of the Project	March 25, 2011	Non-payment
Killingholme	$134,087	Payments Due Under Turbine Service Agreement	November 1, 2006	Credit Agreement default
NRG McClain LLC	Indeterminate	Guarantee of Share Purchase Agreement	2015	Cancellation of Turbine Service Agreement
MIBRAG	Indeterminate	Site Remediation Obligation	None stated	Non-performance

Project/Subsidiary	Guarantee/Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
	(In thousands)			
Mid-Atlantic (Conectiv)	$2,400	Obligation to Fund Liquidated Damages no Paid by EPC Contractor	None stated	Non-performance
LSP Nelson LLC	$30,670	Payment of Cost Overruns Caused by Force Majeure During Construction	May 8, 2006 (Expiration of Construction Revolver)	Non-payment
LSP Nelson LLC	Indeterminate	Guarantee of Power	May 8, 2006 (Expiration of Construction Revolver)	Non-payment
NEO California Power LLC	$10,206	Delivery Obligations	None stated	Non-performance
NRG Finance Co.	Indeterminate	Interest Payments to Lenders if Borrower has Insufficient Funds to Pay Current Interest	May 8, 2006 (Expiration of Construction Revolver)	Non-payment
LSP Pike Energy LLC	$8,800	Liquidated Damages	May 8, 2006 (Expiration of Construction Revolver)	Non-payment
LSP Pike Energy LLC	Indeterminate	Guarantee of Performance of EPC Contractor	May 8, 2006 (Expiration of Construction Revolver)	Non-payment
LSP Pike Energy LLC	Indeterminate	Guarantee of Payment of Cost Overruns	May 8, 2006 (Expiration of Construction Revolver)	Non-payment
LSP Pike Energy LLC	Indeterminate	Guarantee of Payments for Cost Overruns Under the Water Plan	May 8, 2006 (Expiration of Construction Revolver)	Non-payment
Saguaro	$754	Guarantee of Tax Indemnity Payments	Undetermined	Non-payment
SLAP I	Indeterminate	Guarantee of Subscription Agreement in Favor of Scudder Latin American Power I-P LDC & I-C LDC	None stated	Non-performance
West Coast LLC	$750	Guarantee of Environmental Clean Up Costs Continuing Obligations Under Asset	None stated	Non-performance
West Coast LLC (CP I)	Indeterminate	Sales Agreement and Related Contracts (shared with Dynegy)	None stated	Non-performance

NRG Energy, Inc.'s Cash Collateral Obligations as of September 30, 2003

Project/Subsidiary	Cash Collateral Amount	Nature of Collateral Call	Expiration Date	Triggering Event
	(In thousands)			
Brazos Valley	$75,527	Equity Infusion	December 1, 2006	Non-payment
Killingholme	$24,160	Debt Service Reserve Guarantee	None Stated	Non-payment
McClain LLC	$4,589	Debt service reserve guarantee	November 1, 2006	Credit Agreement default
Mid-Atlantic (Conectiv)	$23,163	Debt service reserve guarantee	November 13, 2005	Credit Agreement default
Northeast Generating LLC(*)	$39,423	Debt service reserve guarantee	2004, 2015, 2024 Upon Bond Repayments	Credit Agreement default
NRG Finance Company I LLC	$842,500	Obligation to Make Equity Infusion	None stated	Non-payment
Peaker Finance Co	$34,500	Penalty for Early Termination	June 18, 2019	Non-performance
Peaker Finance Co	$30,380	Shortfall in Revenue	June 18, 2019	Non-performance
Peaker Finance Co	$6,500	Late Completion of a Project	December 31, 2003	Non-performance
South Central Generating LLC(**)	$40,203	Fund Debt Service Reserve in the Event of Payment Default	2016 and 2024 Upon Bond Repayment	Credit Agreement default
RG Turbines LLC	$56,600	If Insufficient Funds in Construction Revolver, NRG Energy Must Fund all Remaining Turbine Payments	May 8, 2006 (Expiration of Construction Revolver)	Credit Agreement default

Recourse provisions for each of the guarantees above are to the extent of their respective liability. Absent an explicit cap per the respective guarantee, maximum exposure amounts project potential maximum exposure. Indeterminate amounts reflect those guarantees with no explicit cap amount. Additionally, no assets are held as collateral for any of the above guarantees.

* The cash collateral amount for NRG Northeast Generating LLC reflects the six-month forward principal and interest payment due on June 16, 2003 per the bond indenture. This amount excludes the outstanding principal payment of $53.5 million that was due on December 16, 2002. Further, this amount excludes any adjustments to interest related to the missed principal payment.

** The cash collateral amount for NRG South Central Generating LLC reflects the six-month forward principal and interest payment due on September 15, 2003 per the bond indenture. This amount excludes the outstanding principal payment of $12.8 million that was due on September 16, 2002 as well as the outstanding principal payment of $12.8 million that was due on March 17, 2003. Further, this amount excludes any adjustments to interest related to the missed principal payments.

10. Segment Reporting

NRG Energy conducts its business within six segments: Independent Power Generation in North America, Europe, Asia Pacific and Other Americas regions, Alternative Energy and Thermal projects. These segments are distinct components of NRG Energy with separate operating results and management structures in place. The "Other" category includes operations that do not meet the threshold for separate disclosure and corporate charges (primarily interest expense) that have not been allocated to the operating segments. Segment information for the three and nine months ended September 30, 2003 and 2002 is as follows:

	For the Three Months Ended September 30, 2003 Power Generation			
	North America	Europe	Asia Pacific	Other Americas
	(In thousands)			
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 450,219	$32,462	$48,170	$19,397
Equity in earnings/(losses) of unconsolidated affiliates	46,225	8,181	8,407	593
Total operating revenues and equity earnings	496,444	40,643	56,577	19,990
Write downs and (gains)/losses on equity method investments	(12,310)	—	—	—
Restructuring professional fees and expenses	1,266	—	—	—
Reorganization items	8,622	(3,311)	(685)	906
Net Income (Loss) from continuing operations	67,070	19,623	9,732	2,616
Net Income (Loss) from discontinued operations	(1,084)	1	604	—
Net Income (Loss)	65,986	19,624	10,336	2,616
Balance Sheet Total assets	$6,990,454	$757,483	$846,416	$504,289

	For the Three Months Ended September 30, 2003			
	Alternative Energy	Thermal	Other	Total
	(In thousands)			
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 30,076	$ 26,981	$ 704	$ 608,009
Equity in earnings/(losses) of unconsolidated affiliates	330	—	(464)	63,272
Total operating revenues and equity earnings	30,406	26,981	240	671,281
Write downs and (gains)/losses on equity method investments	—	—	—	(12,310)
Reorganization items	—	—	19,432	20,698
Legal settlement	—	—	396,000	396,000
Restructuring and impairment charges	(1)	—	721	6,252
Net Income (Loss) from continuing operations	4,504	1,889	(389,124)	(283,690)
Net Income (Loss) from discontinued operations	(625)	—	—	(1,104)
Net Income (Loss)	3,879	1,889	(389,124)	(284,794)
Balance Sheet Total assets	$126,483	$275,029	$ 674,618	$10,174,772

	For the Three Months Ended September 30, 2002 Power Generation			
	North America	Europe	Asia Pacific	Other Americas
	(In thousands)			
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 486,444	$ 27,943	$ 39,067	$ 13,790
Equity in earnings/ (losses) of unconsolidated affiliates	29,813	628	8,217	248
Total operating revenues and equity earnings	516,257	28,571	47,284	14,038
Write downs and (gains)/losses on equity method investments	49,992	—	67,877	—
Restructuring and impairment charges	2,068,740	43,628	(1,476)	147
Net Income (Loss) from continuing operations	(1,874,229)	(42,440)	(58,192)	2,955
Net Income (Loss) from discontinued operations	(458)	(478,916)	(100,248)	(36)
Net Income (Loss)	(1,874,687)	(521,356)	(158,440)	2,919
Balance Sheet Total assets	$ 7,068,073	$1,277,484	$ 850,868	$498,574

	For the Three Months Ended September 30, 2002			
	Alternative Energy	Thermal	Other	Total
	(In thousands)			
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 34,423	$ 26,185	$ (500)	$ 627,352
Equity in earnings/ (losses) of unconsolidated affiliates	(13,574)	—	588	25,920
Total operating revenues and equity earnings	20,849	26,185	88	653,272
Write downs and (gains)/losses on equity method investments	—	—	—	117,869
Restructuring and impairment charges	260	47	376,400	2,487,746
Net Income (Loss) from continuing operations	(21,193)	1,942	(477,779)	(2,468,936)
Net Income (Loss) from discontinued operations	(6,800)	—	—	(586,458)
Net Income (Loss)	(27,993)	1,942	(477,779)	(3,055,394)
Balance Sheet Total assets	$149,813	$259,196	$1,584,405	$11,688,413

	For the Nine Months Ended September 30, 2003 Power Generation			
	North America	Europe	Asia Pacific	Other Americas
	(In thousands)			
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 1,171,718	$ 96,318	$ 131,186	$ 57,006
Equity in earnings/ (losses) of Unconsolidated affiliates	114,811	23,641	17,232	2,162
Total operating revenues and equity earnings	1,286,529	119,959	148,418	59,168
Write downs and (gains)/losses on equity method investments	(12,124)	(2,870)	139,454	—
Reorganization items	2,718	—	—	—
Restructuring and impairment charges	236,497	(7,510)	1,027	97
Net Income (Loss) from continuing operations	(277,401)	51,148	(127,122)	7,502
Net Income (Loss) from discontinued operations	(109,810)	200,069	2,678	—
Net Income (Loss)	(387,211)	251,217	(124,444)	7,502

	For the Nine Months Ended September 30, 2003			
	Alternative Energy	Thermal	Other	Total
	(In thousands)			
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 68,352	$87,669	$ 4,620	$ 1,616,869
Equity in earnings/ (losses) of Unconsolidated affiliates	(1,047)	—	(1,041)	155,758
Total operating revenues and equity earnings	67,305	87,669	3,579	1,772,627
Write downs and (gains)/losses on equity method investments	12,257	—	—	136,717
Reorganization items	—	—	24,314	27,032
Legal settlement	—	—	396,000	396,000
Restructuring and impairment charges	(1)	16	67,893	298,019
Net Income (Loss) from continuing operations	(5,955)	8,615	(616,568)	(959,781)
Net Income (Loss) from discontinued operations	(23,322)	—	(15,661)	53,954
Net Income (Loss)	(29,277)	8,615	(632,229)	(905,827)

	For the Nine Months Ended September 30, 2002 Power Generation			
	North America	Europe	Asia Pacific	Other Americas
	(In thousands)			
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 1,174,645	$ 77,071	$ 137,611	$44,864
Equity in earnings/ (losses) of unconsolidated affiliates	72,763	10,845	18,303	607
Total operating revenues and equity earnings	1,247,408	87,916	155,914	45,471
Write downs and (gains)/losses on equity method investments	49,992	—	72,045	—
Restructuring and impairment charges	2,068,740	44,678	(1,476)	147
Net Income (Loss) from continuing operations	(1,788,088)	(27,468)	(61,708)	6,281
Net Income (Loss) from discontinued operations	(5,156)	(462,197)	(102,015)	(9,633)
Net Income (Loss)	(1,793,244)	(489,665)	(163,723)	(3,352)

	For the Nine Months Ended September 30, 2002			
	Alternative Energy	Thermal	Other	Total
	(In thousands)			
Operating Revenues and Equity Earnings				
Revenues from majority-owned operations	$ 81,257	$84,165	$ 3,246	$ 1,602,859
Equity in earnings/ (losses) of unconsolidated affiliates	(33,734)	—	132	68,916
Total operating revenues and equity earnings	47,523	84,165	3,378	1,671,775
Write down and (gains)/losses on equity method investments	5,678	—	—	127,715
Restructuring and impairment charges	25,704	47	395,830	2,533,670
Net Income (Loss) from continuing operations	(26,521)	8,146	(638,281)	(2,527,639)
Net Income (Loss) from discontinued operations	(16,569)	—	—	(595,570)
Net Income (Loss)	(43,090)	8,146	(638,281)	(3,123,209)

11. Commitments and Contingencies

California Wholesale Electricity Litigation and Related Investigations

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

This action was filed in state court on March 11, 2002. It alleges that the defendants violated California Business & Professions Code § 17200 by selling ancillary services to the California ISO, and subsequently selling the same capacity into the spot market. The Attorney General seeks injunctive relief as well as restitution, disgorgement and civil penalties.

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

The Attorney General filed motions to remand, which the defendants opposed in July of 2002. In an Order filed in early September 2002, Judge Walker denied the remand motions. The Attorney General has appealed that decision to the United States Court of Appeal for the Ninth Circuit, and the appeal is pending. The Attorney General also sought a stay of proceedings in the district court pending the appeal, and this request was also denied. A "Notice of Bankruptcy Filing" respecting NRG Energy was filed in the Ninth Circuit and in the District Court in mid-December 2002. The Attorney General filed a paper asserting that the "police power" exception to the automatic stay is applicable here. Judge Walker agreed with the Attorney General on this issue. In a lengthy opinion filed March 25, 2003, Judge Walker dismissed the Attorney General's action against NRG and Dynegy with prejudice, finding it was barred by the filed rate doctrine and preempted by federal law. The Attorney General filed a Notice of Appeal, and the appeal was argued in August 2003 and also is pending. NRG Energy also filed a "Notice of Bankruptcy Filing" in the Ninth Circuit shortly after its Chapter 11 filing, and the Ninth Circuit issued a stay as to NRG Energy. NRG Energy is unable at this time to accurately estimate the damages sought by the Attorney General against NRG Energy and its affiliates, or predict the outcome of the case.

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

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

The action was transferred from Los Angeles to the United States District Court in San Diego and was made a part of the Multi-District Litigation proceeding described below. All defendants filed motions to dismiss and to strike in the fall of 2002. In an Order dated January 6, 2003, the Honorable Robert Whaley, a federal judge from Spokane sitting in the United States District Court in San Diego, pursuant to the Order of the MDL Panel, granted the motions to dismiss on the grounds of federal preemption and filed-rate doctrine. The plaintiffs have filed a notice of appeal, and the appeal is pending.

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

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

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

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

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

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

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

These cases were all filed in late 2000 and 2001 in various state courts throughout California. They allege unfair competition, market manipulation, and price fixing. All the cases were removed to the appropriate United States District Courts, and were thereafter made the subject of a petition to the Multi-District Litigation Panel (Case No. MDL 1405). The cases were ultimately assigned to Judge Whaley. Judge Whaley entered an order in 2001 remanding the cases to state court, and thereafter the cases were coordinated pursuant to state court coordination proceedings before a single judge in San Diego Superior Court. Thereafter, Reliant Energy and Duke Energy filed cross-complaints naming various Canadian, Mexican and United States government entities. Some of these defendants once again removed the cases to federal court, where they were again assigned to Judge Whaley. The defendants filed motions to dismiss and to strike under the filed-rate and federal preemption theories, and the plaintiffs challenged the district court's jurisdiction and sought to have the cases remanded to state court. In December 2002, Judge Whaley issued an opinion finding that federal jurisdiction was absent in the district court, and remanding the cases to state court. Duke Energy and Reliant Energy then filed a notice of appeal with the Ninth Circuit, and also sought a stay of the remand pending appeal. The stay request was denied by Judge Whaley. On February 20, 2003, however, the Ninth Circuit stayed the remand order and accepted jurisdiction to hear the appeal of Reliant Energy and Duke Energy on the remand order. The Company anticipates that filed-rate/federal preemption pleading challenges will be renewed once the remand appeal is decided. A "Notice of Bankruptcy Filing" respecting NRG Energy has also been filed in this action. We are not active in the appeal, which remains pending.

"Northern California" cases against various market participants, not including NRG Energy (part of MDL 1405). These include the *Millar, Pastorino, RDJ Farms, Century Theatres, El Super Burrito, Leo's, J&M Karsant,* and the *Bronco Don* cases. NRG Energy was not named in any of these cases, but in virtually all of them, either West Coast Power or one or more of the operating LLC's with which NRG Energy is indirectly affiliated is named as a defendant. These cases all allege violation of Business & Professions Code § 17200, and are similar to the various allegations made by the Attorney General. Dynegy is named as a defendant in all these actions, and Dynegy's outside counsel is representing both Dynegy and the West Coast Power entities in each of these cases. These cases all were removed to federal court, made part of the Multi-District Litigation, and denied remand to state court. In late August 2003, Judge Whaley granted the defendants' motions to dismiss in these various cases.

Bustamante v. McGraw-Hill Companies Inc., et al., No. BC 235598, California Superior Court, Los Angeles County. This putative class action lawsuit was filed on November 20, 2002. In addition to naming WCP-related entities as defendants, numerous industry participants are named in this lawsuit that are unrelated to WCP or NRG Energy. The Complaint generally alleges that the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades. Named defendants in the suit are the LLCs established by WCP for each of its four plants: El Segundo Power, LLC; Long Beach Generation, LLC; Cabrillo Power I LLC; and Cabrillo Power II LLC. NRG Energy is not named as a defendant. The complaint seeks restitution and disgorgement of "ill-gotten gains", civil fines, compensatory and punitive damages, attorneys' fees, and declaratory and injunctive relief. The plaintiff recently filed an amended complaint.

Jerry Egger, et al. v. Dynegy Inc., et al., Case No. 809822, Superior Court of California, San Diego County (filed May 1, 2003). This class action Complaint alleges violations of California's Antitrust Law, Business and Professional Code, and unlawful and unfair business practices. The named defendants include "West Coast Power, Cabrillo II, El Segundo Power, Long Beach Generation." NRG Energy is not named.

This case now has been removed to the U.S. District Court, and the defendants have moved to have this case included as Multi-District Litigation along with the above referenced cases before Judge Walker. Plaintiffs have stated an intention to file a motion to remand to state court. Plaintiffs filed an amended complaint in federal court in October, 2003. *Egger* essentially replaces the *"Pacific Northwest"* cases referenced below. This case is the subject of an MDL petition.

"Pacific Northwest" cases: *Symonds v. Dynegy Power Marketing, NRG Energy, Inc., Xcel Energy, Inc., West Coast Power LLC, et al.,* United States District Court, Western District of Washington, Case No. CV02-2552; *Lodewick v. Dynegy Power Marketing, NRG Energy, Inc., Xcel Energy, Inc., West Coast Power LLC, et al.,* Oregon Circuit Court Case No. 0212-12771. NRG Energy is represented in these matters by Thomas Nelson of Portland. *Lodewick* was removed to federal court, and both cases were briefly the subject of MDL 1533. In early May, plaintiffs in both cases requested voluntary dismissal of the actions.

Investigations

FERC — California Market Manipulation

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

In August 2002, the 9th U.S. Circuit Court of Appeals granted a request by the Electricity Oversight Board, the California Public Utilities Commission, and others, to seek out and introduce to FERC additional evidence of market manipulation by wholesale sellers. This decision resulted in FERC ordering an additional 100 days of discovery in the refund proceeding, and also allowing the relevant time period for potential refund liability to extend back an additional nine months, to January 1, 2000.

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

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

Through its subsidiary NRG West Coast Inc., NRG Energy is essentially a joint venturer with Dynegy, Inc. in West Coast Power LLC (WCP), which owns, operates, and markets the power of California plants.

Dynegy and its affiliates and subsidiaries are responsible for gas procurement and marketing and trading activities on behalf of the joint venture. On December 18, 2002, a Dynegy subsidiary, Dynegy Marketing & Trade (DMT), and West Coast Power LLC (Respondents), entered into a consent Offer of Settlement and Order (Consent Order) with the Commodity Futures and Trading Commission (CFTC). The action is captioned In re Dynegy Marketing & Trade and West Coast Power LLC, CFTC Docket No. 03-03. The CFTC asserted various violations of the Commodity Exchange Act, as well as CFTC regulations.

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

U.S. Attorney — Houston

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

U.S. Attorney — San Francisco

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

California State Senate Select Committee

This Committee, chaired by Senator Dunn, subpoenaed records from NRG Energy during the Summer of 2001. NRG Energy produced about 5,000 pages of documents; Dynegy produced a much larger volume of documents. The Committee is scheduled to sunset later this year.

California PUC

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

California Attorney General

In addition to the litigation it has undertaken described above, the California Attorney General has undertaken an investigation entitled "In the Matter of the Investigation of Possibly Unlawful, Unfair, or Anti-Competitive Behavior Affecting Electricity Prices in California." In this connection, the Attorney General has issued subpoenas to Dynegy, served interrogatories on Dynegy and NRG Energy, and informally requested documents and interviews from Dynegy and Dynegy employees as well as NRG Energy and NRG Energy employees. NRG Energy responded to the interrogatories last summer, with the final set of responses being served on September 3, 2002. NRG Energy has also produced a large volume of documentation relating to the West Coast Power plants. In addition, NRG Energy employees in California have sat for informal interviews with representatives of the Attorney General's office. Dynegy employees have also been interviewed.

Although any evaluation of the likelihood of an unfavorable outcome or an estimate of the amount or range of potential loss in the above-referenced private actions and various investigations cannot be made at this time, NRG Energy notes that the Gordon complaint alleges that the defendants, collectively, overcharged California ratepayers during 2000 by $4.0 billion. NRG Energy knows of no evidence implicating NRG Energy in plaintiffs' allegations of collusion. NRG Energy cannot predict the outcome of these cases and investigations at this time.

The New York Voluntary Bankruptcy Case

On May 14, 2003 NRG Energy and certain of its U.S. affiliates filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code (the Bankruptcy Code) in the United States Bankruptcy Court for the Southern District of New York (the Bankruptcy Court), In re: NRG ENERGY, INC., et. al., Case No. 03-13024 (PCB). NRG Energy expects operations to continue as normal during the restructuring process, while it operates its business as a "debtor-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

Fortistar Capital Inc. v. NRG Energy, Inc., Hennepin County District Court

On July 12, 1999, Fortistar Capital Inc. (Fortistar) sued NRG Energy in Minnesota state court. The complaint sought injunctive relief and damages of over $50 million resulting from NRG Energy's alleged breach of a letter agreement with Fortistar relating to the Oswego power plant. NRG Energy asserted counterclaims. After considerable litigation, the parties entered into a conditional, confidential settlement agreement, which was subject to necessary board and lender approvals. NRG Energy was unable to obtain necessary approvals. Fortistar initially moved the court to enforce the settlement, seeking damages in excess of $35 million plus interest and attorneys' fees. NRG Energy opposed Fortistar's motion on the grounds that conditions to contract performance had not been satisfied. In July 2003, Fortistar purported to withdraw its motion without prejudice and sought relief from stay at the Bankruptcy Court to liquidate its bankruptcy claim by trying the action in the Minnesota State Court. The Bankruptcy Court denied Fortistar's relief from stay motion and Fortistar is now seeking relief and review at the United States District Court for the Southern District of New York. NRG Energy cannot predict the outcome of this dispute.

Fortistar RICO Claims/ Indemnity Requests

On February 26, 2003, Fortistar Capital, Inc. and Fortistar Methane, LLC filed a lawsuit in the Federal District Court for the Northern District of New York against Xcel Energy and five present or former NRG Energy or NEO Corporation (NEO) officers and employees. NRG Energy is a wholly owned subsidiary of Xcel Energy, and NEO is a wholly owned subsidiary of NRG Energy. In the lawsuit, Fortistar claims that the defendants violated the Racketeer Influenced and Corrupt Organizations Act (RICO) and committed fraud by engaging in a pattern of negotiating and executing agreements "they intended not to comply with" and "made false statements later to conceal their fraudulent promises." The plaintiffs allege damages of some $350 million and also assert entitlement to a trebling of these damages under the provisions of the RICO Act. The present and former NRG Energy and NEO officers and employees have requested indemnity from NRG

Energy and NEO, and NEO is indemnifying its respective agents. NRG Energy cannot at this time estimate the likelihood of an unfavorable outcome to the defendants in this lawsuit.

NEO Corporation, a Minnesota Corporation on Behalf of Itself and on Behalf of Minnesota Methane, LLC, a Delaware Limited Liability Company v. Fortistar Methane, LLC, a Delaware Limited Liability Company, Hennepin County District Court

NEO Corporation, a wholly owned subsidiary of NRG Energy, brought this lawsuit in January of 2001. NEO asserted claims for breach of contract, breach of the covenant of good faith and fair dealing, fraudulent misrepresentations and omissions, defamation, business disparagement and derivative claims. Fortistar Methane, LLC denied NEO's claims and counterclaimed alleging breach of contract, fraud, negligent misrepresentation and breach of warranty. NEO denied Fortistar Methane's claims. Discovery has not been conducted. The parties entered into a conditional, confidential settlement of this matter and the Fortistar Capital action, described above. The agreement, however, was subject to necessary board and lender approvals. NEO was unable to obtain necessary approvals. Fortistar Methane initially moved to enforce the settlement, seeking damages against NRG Energy in excess of $35 million plus interest and attorneys' fees. NRG Energy and NEO opposed Fortistar's motion on the grounds that conditions to contract performance were not met. NRG Energy cannot predict the likelihood of an unfavorable outcome.

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

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

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

This matter involves a dispute between CL&P and NRG PMI concerning which of those parties is responsible, under the terms of the October 29, 1999 Standard Offer Services contract, for costs related to congestion and losses associated with the implementation of standard market design (SMD-Related Costs). CL&P has withheld, beyond the $30 million discussed above, an additional approximately $70 million from amounts owed to NRG PMI, claiming that it is entitled under the contract to offset those additional amounts for SMD-Related Costs. NRG PMI cannot estimate at this time the likelihood of an unfavorable outcome in this matter, or the overall exposure for SMD-Related Costs for the full term of the contract.

Connecticut Light & Power — Related Proceedings at the Federal Energy Regulatory Commission, the United States District Court for the Southern District of New York, and the United States Court of Appeals for the D.C. Circuit and the Second Circuit.

In May 2003, NRG PMI took steps to terminate or reject in bankruptcy the subject Standard Offer Services contract. CL&P, the Connecticut Attorney General and the Connecticut Department of Public Utility Control (DPUC) sought and obtained from FERC an Order dated May 16, 2003, temporarily requiring NRG PMI to continue to comply with the terms of the contract, pending further notice from FERC. Thereafter, On June 2, 2003, the United States Bankruptcy Court for the Southern District of New York issued its Order specifically authorizing NRG PMI's rejection of the contract, and by Order dated June 12, 2003, the United States District Court for the Southern District of New York granted NRG PMI's motion for a temporary restraining order staying all actions by CL&P, the Connecticut Attorney General and the DPUC to enforce or apply the above-referenced FERC Order and affording NRG PMI leave to cease its performance under the contract, effective retroactive to June 2, 2003. FERC then issued an order on June 25, 2003 (June 25 Order), that again commanded NRG PMI's continued performance regardless of any contrary ruling by the Bankruptcy Court and the District Court's temporary restraining order. By order dated June 30, 2003, the District Court reversed itself and dismissed NRG PMI's motion for preliminary injunction for lack of subject matter jurisdiction. On July 18, 2003, NRG PMI appealed to the Second Circuit respecting the District Court's refusal to enjoin FERC. On August 15, 2003, FERC issued orders denying rehearing of the June 25 Order and requiring NRG PMI to continue to perform under the Standard Offer Services contract (the June 25 Order, together with the August 15 Orders, the Commission Orders). NRG PMI filed a request for rehearing with FERC and a petition for review in the United States Court of Appeals for the District of Columbia Circuit in Case No. 03-1346 relating to the Commission Orders. On November 4, 2003, the parties reached a settlement under which the Second Circuit and D.C. Circuit litigation respecting the above matters will be dismissed, while preserving the parties' rights to litigate those matters which are before the United States District Court for the District of Connecticut and FERC, as previously discussed. The settlement does not affect issues between CL&P and NRG Energy, Inc., related to station service, described hereafter, which will be separately arbitrated. The settlement is subject to regulatory and legal approvals, including approval from FERC and the United States Bankruptcy Court for the Southern District of New York.

The State of New York and Erin M. Crotty, as Commissioner of the New York State Department of Environmental Conservation v. Niagara Mohawk Power Corporation et al., United States District Court for the Western District of New York, Civil Action No. 02-CV-002S

In January 2002, NRG Energy and Niagara Mohawk Power Corporation (NiMo) were sued by the New York Department of Environmental Conservation in federal court in New York. The complaint asserted that projects undertaken at NRG Energy's Huntley and Dunkirk plants by NiMo, the former owner of the facilities, required preconstruction permits pursuant to the Clean Air Act and that the failure to obtain these permits violated federal and state laws. In July 2002, NRG Energy filed a motion to dismiss. On March 27, 2003 the court dismissed the complaint against NRG Energy with prejudice as to the federal claims and without prejudice as to the state claims. It is possible the state will appeal this dismissal to the Second Circuit Court of Appeals. In the meantime, on April 25, 2003, the state provided to NRG Energy notice of intent to again sue the Company and various affiliates by filing a second amended complaint in this same action in the federal court in New York, asserting against the NRG Defendants violations of operating permits and deficient operating permits at the Huntley and Dunkirk plants. The NRG Defendants have moved to dismiss the second amended complaint, and that motion is now under advisement. If the case ultimately is litigated to a judgment and there is an unfavorable outcome that could not be addressed otherwise, NRG Energy has estimated that the total investment that would be required to install pollution control devices could be as high as $300 million over a ten to twelve-year period.

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

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

Huntley Power LLC, Dunkirk Power LLC and Oswego Power LLC

All three of these facilities have been issued Notices of Violation with respect to opacity exceedances. The above entities have been engaged in consent order negotiations with the New York State Department of Environmental Conservation (DEC) relative to opacity issues affecting all three facilities since the plants were acquired. It appears that by year-end, the parties will finalize the terms of a consent order, which will quantify the number of opacity exceedances at the three facilities through the second quarter of 2003 and set a cumulative penalty, presently anticipated to be some $1 million. In the event that the consent order negotiations prove unsuccessful, it is not known what relief the DEC will seek through an enforcement action and what the result of such action will be.

Huntley Power LLC

On April 30, 2003, the Huntley Station submitted a self-disclosure letter to the New York Department of Environmental Conservation (DEC) reporting violations of applicable sulfur in fuel limits, which had occurred during 6 days in March 2003 at the chimney stack serving Huntley Units 63-66. The Huntley Station self-disclosed that the average sulfur emissions rates for those days had been 1.8 lbs/mm BTU, rather than the maximum allowance of 1.7 lbs/mm BTU. NRG Huntley Operations discontinued use of Unit 65 (the only unit utilizing the subject stack at the time) and has kept the remaining 3 units off line until adherence with the applicable standard is assured. On May 19, 2003, the DEC issued Huntley Power LLC a Notice of Violation. The Company has met with the DEC to discuss the circumstances surrounding the event and the appropriate means of resolving the matter. The Company does not know what relief the DEC will seek through an enforcement action. Under applicable provisions of the Environmental Conservation Law, the DEC asserts that it may impose a civil penalty up to $10,000, plus an additional penalty not to exceed $10,000 for each day that a violation continues and may enjoin continuing violations.

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

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

After proceeding through discovery, and prior to trial, the parties and the court entered into a stipulation and order filed August 9, 2002 consolidating this action with two other actions against NRG Northeast's

Huntley and Oswego subsidiaries, both of which cases assert the same claims and legal theories for failure to pay retail tariffs for utility services.

On October 8, 2002, a Stipulation and Order was filed in the Erie County Clerk's Office staying this action pending submission of some or all of the disputes in the action to the FERC. NRG Energy cannot make an evaluation of the likelihood of an unfavorable outcome. The cumulative potential loss could exceed $35 million.

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

This is the companion action filed by Niagara Mohawk at FERC, similarly asserting that Niagara Mohawk is entitled to receive retail tariff amounts for electric service provided to the Huntley, Dunkirk and Oswego plants. On October 31, 2003, the FERC Trial Staff, a party to the proceedings, filed a reply brief in which they supported and agreed with each position taken by the NRG Generators in their initial brief. In short, the staff argued that the NRG Generators: (1) self-supply station power under the NYISO tariff (which took effect on April 1, 2003), in any month during which they produce more energy than they consume and, as such should not be assessed a retail rate; (2) are connected only to transmission facilities and as such, at most should only pay NiMo a FERC-approved transmission rate; and (3) should be allowed to net consumption and output even if power is injected into the grid at a different point from which it is drawn off. The parties are currently engaged in settlement negotiations which, should they prove successful, will resolve both this FERC action and the above-referenced state court proceedings respecting amounts owing for electrical service provided to these three plants. At this stage of the proceedings, we cannot estimate the likelihood of an adverse determination. As noted above, the cumulative potential loss could exceed $35 million.

Pointe Coupee Parish Police Jury and Louisiana Generating, LLC v. United States Environmental Protection Agency and Christine Todd Whitman, Administrator, Adversary Proceeding No. 02-61021 on the docket of the United States Court of Appeals for the Fifth Circuit

On December 2, 2002, a Petition for Review was filed to appeal the United States Environmental Protection Agency's approval of the Louisiana Department of Environmental Quality's (DEQ) revisions to the Baton Rouge State Implementation Plan (SIP). Pointe Coupee and NRG Energy's subsidiary, Louisiana Generating, object to the approval of SIP Section 4.2.1. Permitting NO_x Sources that purports to require DEQ to obtain offsets of major increases in emissions of nitrogen oxides (NO_x) associated with major modifications of existing facilities or construction of new facilities both in the Baton Rouge Ozone Nonattainment Area and in four adjoining attainment parishes referred to as the Region of Influence, including Pointe Coupee Parish. The plaintiffs' challenge is based on DEQ's failure to comply with Administrative Procedures Act requirements related to rulemaking and EPA's regulations, which prohibit EPA from approving a SIP not prepared in accordance with state law. The action is currently stayed by the United States Fifth Circuit Court of Appeals in response to the filing of the Suggestion of Bankruptcy, and the parties have been engaged in settlement discussions in the meantime. EPA has just served notice that it intends to withdraw its approval of DEQ's Attainment Demonstration and will thereupon move to voluntarily dismiss the action as moot.

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

During 2000, DEQ issued a Part 70 Air Permit modification to Louisiana Generating to construct and operate two 240 MW natural gas-fired turbines. The Part 70 Air Permit set emissions limits for the criteria air pollutants, including NO_x, based on the application of Best Available Control Technology (BACT). The BACT limitation for NO_x was based on the guarantees of the manufacturer, Siemens-Westinghouse. Louisiana Generating sought an interim emissions limit to allow Siemens-Westinghouse time to install additional control equipment. To establish the interim limit, DEQ issued a Compliance Order and Notice of Potential Penalty, No. AE-CN-02-0022, on September 8, 2002, which is, in part, subject to the referenced administrative hearing. DEQ alleged that Louisiana Generating did not meet its NO_x emissions limit on certain days, did not conduct all opacity monitoring and did not complete all record keeping and certification requirements. Louisiana Generating intends to vigorously defend certain claims and any future penalty assessment, while also seeking an amendment of its limit for NO_x. An initial status conference has been held with the Administrative Law Judge and quarterly reports will be submitted to describe progress, including settlement and amendment of the limit. The extension of an amended BACT analysis has been granted until December 31, 2003. In addition, NRG Energy may assert breach of warranty claims against the manufacturer. With respect to the administrative action described above, at this time NRG Energy is unable to predict the eventual outcome of this matter or the potential loss contingencies, if any, to which the Company may be subject.

NRG Sterlington Power, LLC

During 2002, NRG Sterlington conducted a review of the Sterlington Power Facility's Part 70 Air Permit obtained by the facility's former owner and operator, Koch Power, Inc. Koch had outlined a plan to install eight 25 megawatt (MW) turbines to reach a 200 MW limit in the permit. Due to the inability of several units to reach their nameplate capacity, Koch determined that it would need additional units to reach the electric output target. In August 2000, NRG Sterlington acquired the remaining interests in the facility not originally held on a passive basis and sought the transfer of the Part 70 Air Permit along with a modification to incorporate two 17.5 MW turbines installed by Koch and to increase the total number of turbines to ten. The permit modification was issued February 13, 2002. During further review, NRG Sterlington determined that a ninth unit had been installed prior to issuance of the permit modification. In keeping with its environmental policy, it disclosed this matter to DEQ in April 2002. NRG Sterlington provided to DEQ additional information during July 2002. A Consolidated Compliance Order & Notice of Potential Penalty, No. AE-CN-01-0393, was issued by DEQ on September 10, 2003, wherein DEQ formally alleged that NRG Sterlington did not complete all certification requirements, and installed a ninth unit prior to issuance of its permit modification. A meeting with DEQ is scheduled for November 19, 2003 to discuss mitigating circumstances and to seek to resolve all matters. NRG Energy is unable at this time to predict the eventual outcome or potential loss contingencies, if any, to which the Company may be subject.

Commission for its approval a Consent Agreement establishing that Saguaro does in fact satisfy the requirements for a qualifying facility. NRG Energy awaits the Commission's ruling.

Stone & Webster, Inc. and Shaw Constructors, Inc. v. NRG Energy, Inc. et al.

On October 17, 2002, Stone & Webster, Inc. and Shaw Constructors, Inc. filed a lawsuit in the United States District Court, Southern District of Mississippi, against NRG Energy, Xcel Energy, Inc., NRG Granite Acquisition LLC, Granite Power Partners II LP and two of Xcel Energy's executives relating to the construction of a power plant in Pike County, Mississippi. Plaintiffs generally alleged that they were not paid for work performed to construct the power plant, and sued the parent entities of the company with which they contracted to build the plant in order to recover amounts allegedly owing. Plaintiffs asserted claims for breach of fiduciary duty, piercing the corporate veil, breach of contract, tortious interference with contract, enforcement of the NRG Energy guaranty, detrimental reliance, negligent or intentional misrepresentation, conspiracy, and aiding and abetting. The parties have entered into a global settlement respecting this lawsuit and the dismissal of the Mississippi Involuntary Case, described below, and have executed a settlement agreement, which must be approved by the United States Bankruptcy Courts for the Southern District of New York and Southern District of Mississippi.

The Mississippi Involuntary Case

On October 17, 2002, a petition commencing an involuntary bankruptcy proceeding pursuant to Chapter 7 of the Bankruptcy Code was filed against LSP-Pike Energy, LLC, a subsidiary of NRG Energy, by Stone & Webster, Inc. and Shaw Constructors, Inc. in the United States Bankruptcy Court for the Southern District of Mississippi. In their petition filed with the Mississippi Bankruptcy Court, the petitioners sought recovery of allegedly unpaid contractual construction-related obligations in an aggregate amount of $73.8 million, which amount LSP-Pike Energy, LLC disputed. As set forth above, the parties have reached a global settlement respecting this matter.

FirstEnergy Arbitration Claim

On November 29, 2001, The Cleveland Electric Illuminating Company, The Toledo Edison Company and FirstEnergy Ventures (Sellers) entered into Purchase and Sale Agreements with NRG Able Acquisition LLC, which were guaranteed by NRG Energy (collectively, Purchasers), for the purchase of certain power plants for approximately $1.5 billion. On August 8, 2002, Sellers terminated the agreements and asserted that Purchasers were liable for anticipatory breach of the Purchase and Sale Agreements on the grounds that they could not finance the purchases. On August 8, 2002, Purchasers provided notice that they disagreed with Sellers' assertion. After Sellers filed a motion seeking a waiver of the automatic stay of Section 362(a) of the Bankruptcy Code respecting NRG Energy's then-existing involuntary bankruptcy, the parties stipulated to a waiver of that automatic stay, thereby allowing Sellers to proceed with arbitration, but only for the purpose of liquidating the dollar amount of Sellers' claim. The collection of any award, however, was to remain fully subject to NRG Energy's automatic stay. The parties thereafter obtained relief from stay respecting the present Chapter 11 Bankruptcy, so as to continue the arbitration. The parties have now reached an agreement in principle, which, if consummated and approved by regulators and the United States Bankruptcy Court for the Southern District of New York, will liquidate Sellers' bankruptcy claim at $396 million.

General Electric Company and Siemens Westinghouse Turbine Purchase Disputes

NRG Energy and/or its affiliates have entered into several turbine purchase agreements with affiliates of General Electric Company (GE) and Siemens Westinghouse Power Corporation (Siemens). GE and Siemens have notified NRG Energy that it is in default under certain of those contracts, terminated such contracts, and demanded that NRG Energy pay the termination fees set forth in such contracts. GE's claim amounts to $120 million and Siemens' approximately $45 million in cumulative termination charges. NRG Energy cannot estimate the likelihood of unfavorable outcomes in these disputes.

Itiquira Energetica, S.A.

NRG Energy's indirectly controlled Brazilian project company, Itiquira Energetica S.A., the owner of a 156 MW hydro project in Brazil, is currently in arbitration with the former EPC contractor for the project, Inepar Industria e Construcoes (Inepar). The dispute was commenced by Itiquira in September, 2002 and pertains to certain matters arising under the former EPC contract. Itiquira principally asserts that Inepar breached the contract and caused damages to Itiquira by (i) failing to meet milestones for substantial completion; (ii) failing to provide adequate resources to meet such milestones; (iii) failing to pay subcontractors amounts due; and (iv) being insolvent. Itiquira's arbitration claim is for approximately US $40 million. Inepar has asserted in the arbitration that Itiquira breached the contact and caused damages to Inepar by failing to recognize events of force majeure as grounds for excused delay and extensions of scope of services and material under the contract. Inepar's damage claim is for approximately US $10 million. The parties submitted their respective statements of claims, counterclaims and responses, and a preliminary arbitration hearing was held on March 21, 2003. In lieu of taking expert testimony at hearing, the court of arbitration has ordered an expert investigation process to cover technical and accounting issues. If the court of arbitration determines that the final report from the expert investigation process is inconclusive, it may then require expert testimony. NRG Energy anticipates that the expert investigation process will not be completed sooner than February 2004. NRG Energy cannot estimate the likelihood of an unfavorable outcome in this dispute.

NRG Energy Credit Defaults

NRG Energy and various of its subsidiaries are in default under various of their credit facilities, financial instruments, construction agreements and other contracts, which have given rise to liens, claims and contingencies against them and may in the future give rise to additional liens, claims and contingencies against them. In addition, NRG Energy and various of its subsidiaries have entered into various guarantees, equity contribution agreements, and other financial support agreements with respect to the obligations of their affiliates, which have given rise to liens, claims and contingencies against them and may in the future give rise to additional liens, claims and contingencies against the party or parties providing the financial support. NRG Energy cannot predict the outcome or financial impact of these matters.

12. Inventory

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

	September 30, 2003	December 31, 2002
	(In thousands)	
Fuel oil	$ 68,740	$ 51,442
Coal	64,273	82,554
Kerosene	2,624	2,852
Spare parts	102,661	107,542
Emission credits	9,180	14,742
Natural gas	364	153
Other	7,961	6,300
Total Inventory	$ 255,803	$265,585

13. Property, Plant and Equipment

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

	September 30, 2003	December 31, 2002
	(In thousands)	
Facilities and equipment	$ 6,194,512	$6,324,358
Land and improvements	100,884	108,241
Office furnishings and equipment	69,011	67,086
Construction in progress(1)	460,989	623,750
Total property, plant and equipment	6,825,396	7,123,435
Accumulated depreciation	(771,613)	(602,712)
Net property, plant and equipment	$6,053,783	$6,520,723

In light of economic developments related to the Connecticut assets and the FERC issued order regarding cost of service reimbursements, NRG Energy reassessed the asset lives for the Connecticut facilities. The shorter depreciable lives resulted in an increase in depreciation of approximately $0.7 million and $13.9 million for the three and nine months ended September 30, 2003.

(1) Included in construction in progress is approximately $248.9 million related to turbines associated with cancelled projects as of September 30, 2003 and December 31, 2002, respectively.

14. Derivative Instruments and Hedging Activities

SFAS No. 133 requires NRG Energy to record all derivatives on the balance sheet at fair value. Changes in the fair value of non-hedge derivatives will be immediately recognized in earnings. Changes in fair values of derivatives accounted for as hedges will either be recognized in earnings as offsets to the changes in fair value of related hedged assets, liabilities and firm commitments or, for forecasted transactions, deferred and recorded as a component of other accumulated comprehensive income (OCI) until the hedged transactions occur and are recognized in earnings. The ineffective portion of a hedging derivative instrument's change in fair value will be immediately recognized in earnings. NRG Energy also formally assesses, both at inception and at least quarterly thereafter, whether the derivatives that are used in hedging transactions are highly effective in offsetting the changes in either the fair value or cash flows of the hedged item. This assessment includes all components of each derivative's gain or loss unless otherwise noted. When it is determined that a derivative ceases to be a highly effective hedge, hedge accounting is discontinued.

SFAS No. 133 applies to NRG Energy's long-term power sales contracts, long-term gas purchase contracts and other energy related commodities financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect investments in fuel inventories. SFAS No. 133 also applies to various interest rate swaps used to mitigate the risks associated with movements in interest rates, foreign exchange contracts used to reduce the effect of fluctuating foreign currencies on foreign denominated investments and other transactions. At September 30, 2003, NRG Energy had various commodity contracts extending through December 2003, and several fixed-price gas and electricity purchase contracts extending through 2018.

Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS No. 133 on NRG Energy's OCI balance for the three months ended September 30, 2003:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Accumulated OCI balance at June 30, 2003	$ 52,595	$(78,298)	$ —	$(25,703)
Unwound from OCI during period:				
— Due to unwinding of previously deferred amounts	(11,303)	100	—	(11,203)
— Mark to market of hedge contracts	39,123	7,136	—	46,259
Accumulated OCI balance at September 30, 2003	$ 80,415	$ (71,062)	$ —	$ 9,353

The following table summarizes the effects of SFAS No. 133 on NRG Energy's OCI balance for the nine months ended September 30, 2003:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Accumulated OCI balance at December 31, 2002	$ 129,496	$(102,957)	$ (261)	$ 26,278
Unwound from OCI during period:				
— Rolloff of forecasted transactions no longer being probable	—	32,025	—	32,025
— Due to unwinding of previously deferred amounts	(100,333)	5,750	261	(94,322)
— Mark to market of hedge contracts	51,252	(5,880)	—	45,372
Accumulated OCI balance at September 30, 2003	$ 80,415	$ (71,062)	$ —	$ 9,353
Gains/(Losses) expected to unwind from OCI during next 12 months	$ 46,630	$ (359)	$ —	$ 46,271

Losses of $0 and $32 million were reclassified from OCI to current period earnings during the three and nine months ended September 30, 2003 due to forecasted transactions no longer being probable. Gains of $11.2 million and $94.3 million were reclassified from OCI to current period earnings during the three and nine months ended September 30, 2003, respectively, due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also during the three and nine months ended September 30, 2003, NRG Energy recorded gains in OCI of approximately $46.3 million $45.4 million, respectively, related to changes in the fair values of derivatives accounted for as hedges.

The net balance in OCI relating to SFAS No. 133 as of September 30, 2003 was an unrecognized gain of approximately $9.4 million. NRG Energy expects $46.3 million of deferred net gains on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

Statement of Operations

The following tables summarize the pre-tax effects of SFAS No. 133 on NRG Energy's statement of operations for the three months ended September 30, 2003:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority owned subsidiaries	$ (3,448)	$ —	$ —	$ (3,448)
Equity in earnings of unconsolidated subsidiaries	7,901	—	—	7,901
Cost of operations	1,769	—	—	1,769
Interest expense	—	24,638	—	24,638
Total Statement of Operations impact before tax	$ 6,222	$ 24,638	$ —	$ 30,860

The following tables summarize the pre-tax effects of SFAS No. 133 on NRG Energy's statement of operations for the nine months ended September 30, 2003:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority owned subsidiaries	$ 29,845	$ —	$ —	$ 29,845
Equity in earnings of unconsolidated subsidiaries	11,567	(222)	—	11,345
Cost of operations	(7,386)	—	—	(7,386)
Other income	—	—	92	92
Interest expense	—	(20,970)	—	(20,970)
Total Statement of Operations impact before tax	$ 34,026	$ (21,192)	$ 92	$ 12,926

Energy Related Commodities

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

No ineffectiveness was recognized on commodity cash flow hedges during the three and nine months ended September 30, 2003.

NRG Energy's pre-tax earnings for the three and nine months ended September 30, 2003 were increased by an unrealized gain of $6.2 million and $34.0 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the three and nine months ended September 30, 2003, NRG Energy reclassified gains of $11.3 million and $100.3 million, respectively, from OCI to current-period earnings and expects to reclassify an additional $46.6 million of deferred gains to earnings during the next twelve months on energy related derivative instruments accounted for as hedges.

Interest Rates

To manage interest rate risk, NRG Energy has entered into interest-rate swaps that effectively fix the interest payments of certain floating rate debt instruments. Qualifying interest-rate swap agreements are accounted for as cash flow hedges. The effective portion of the cumulative gain or loss on the derivative instrument is reported as a component of OCI in shareholders' equity and recognized into earnings as the underlying interest expense is incurred. Such reclassifications are included on the same line of the statement of operations in which the hedged item is recorded.

No ineffectiveness was recognized on interest rate cash flow hedges during the three and nine months ended September 30, 2003.

NRG Energy's pre-tax earnings for the three and nine months ended September 30, 2003 were increased by an unrealized gain of $24.6 million and decreased by an unrealized loss $21.2 million, respectively, associated with changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the three and nine months ended September 30, 2003, NRG Energy reclassified losses of $100,000 and $5.8 million from OCI to current-period earnings and expects to reclassify $359,000 of deferred losses to earnings during the next twelve months on interest rate swaps accounted for as hedges.

Foreign Currency Exchange Rates

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

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

NRG Energy's pre-tax earnings for the three and nine months ended September 30, 2003 were increased by an unrealized gain of $0 and $92,000 associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS No. 133.

During the three and nine months ended September 30, 2003, NRG Energy reclassified losses of $0 and $261,000 from OCI to current period earnings and does not expect to reclassify any deferred gains/losses to earnings during the next twelve months on foreign currency swaps accounted for as hedges.

15. Goodwill and Other Intangible Assets

During the first quarter of 2002, NRG Energy adopted SFAS No. 142 — *"Goodwill and Other Intangible Assets" (*SFAS No. 142), which requires new accounting for intangible assets, including goodwill. Intangible assets with finite lives will be amortized over their economic useful lives and periodically reviewed for impairment. Goodwill will no longer be amortized, but will be tested for impairment annually and on an interim basis if an event occurs or a circumstance changes between annual tests that may reduce the fair value of a reporting unit below its carrying value. NRG Energy had intangible assets with a net carrying value of $26.8 million at September 30, 2003, which will not be amortized and consists of goodwill. The majority of NRG Energy's goodwill and other intangible assets are attributable to NRG Energy's Thermal operations which are not subject to NRG Energy's bankruptcy filing. The Thermal operations have historically demonstrated adequate cash flows to justify the existence of such balances.

Aggregate amortization expense recognized for the three months ended September 30, 2003 and 2002 was approximately $1.0 million and $0.7 million, respectively. Aggregate amortization expense recognized for the nine months ended September 30, 2003 and 2002 was approximately $3.1 million and $2.1 million, respectively. The annual aggregate amortization expense for each of the five succeeding years is expected to approximate $4.0 million in each of years one, two and three and $3.9 million in each of years four and five. The estimated useful lives of these amortizable intangibles were reduced effective January 1, 2003 from a range of 3 to 40 years to a range of 3 to 30 years.

Intangible assets consisted of the following:

	At September 30, 2003		At December 31, 2002	
Class of Intangible Asset	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(In thousands)			
Goodwill	$ 32,958	$ 6,124	$ 32,958	$ 6,124
Amortized:				
Service contracts	$ 64,592	$ 19,002	$ 65,791	$ 15,986

16. Regulatory Issues

NRG Energy is impacted by market rule and tariff changes in the existing markets operated by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

On March 1, 2003, ISO-New England implemented its version of Standard Market Design. This change dramatically modifies the New England market structure by incorporating Locational Marginal Pricing (pricing by location rather than on a New England wide basis). While the ISO-New England Standard Market Design represents a significant improvement to the existing market design, NRG Energy still considered the market insufficient to allow NRG Energy to recover its reasonable costs and earn a reasonable return on investment. Therefore, and notwithstanding the impending implementation of Locational Marginal Pricing, on February 26, 2003, NRG Energy filed a proposed cost of service agreement with the Federal Energy Regulatory Commission (FERC) for the following Connecticut facilities: Middletown Power LLC, Montville Power LLC, Norwalk Power LLC and Devon Power LLC units 11-14 (collectively the NRG Subsidiaries). In the filing, NRG Energy requested that major and minor maintenance expenses of the NRG Subsidiaries be paid for through a tracking mechanism that would insure that NRG Energy receives compensation only for actual maintenance expenses. Under the proposed cost of service agreement, the other NRG Energy costs would be paid through a monthly cost-based payment. NRG Energy requested an effective date of February 27, 2003.

On March 25, 2003, FERC issued an order (the March Order) approving the recovery of the NRG Subsidiaries' Spring 2003 maintenance expenses, subject to refund and authorized an effective date of February 27, 2003. FERC did not rule on the remainder of the issues to allow further time to consider protests.

On April 25, 2003, the FERC issued an order (the April Order) rejecting the remaining part of the proposed cost of service agreements including the monthly cost-based payment. Rather, FERC instructed ISO New England to establish temporary bidding rules that would permit selected peaking units (units with capacity factors of 10 percent or less during 2002), operating within “designated congestion areas” (such as Connecticut) to raise their bids to allow them the opportunity to recover their fixed and variable costs through the market. This temporary bidding rule would remain in place until ISO New England implements locational installed capacity requirements, which should be no later than June 1, 2004. In the July 24 Order on Rehearing (the July Order), FERC clarified that the capacity factor of 10 percent or less applies to units rather than complexes. On a unit basis, all the NRG Energy facilities qualify to bid under the temporary rules except Middletown 2 and 3, and Devon 7 and 8. The existing RMR agreement between ISO New England and NRG Energy covering Devon 7 and 8 terminated on September 30, 2003. On October 2, 2003, NRG

Energy filed to extend the existing RMR agreement. FERC has yet to act on the request to extend the agreement. For additional information regarding the impact that the April 25, 2003 FERC order and other regulatory developments had on NRG Energy's results of operations, See Note 4.

On October 17, 2003, the Midwest Independent Transmission Operator, Inc. (MISO) filed a motion to withdraw its Open Access Transmission and Energy Market's Tariff (TEMT), purportedly to allow more time to develop stakeholder consensus on critical outstanding issues relating to market features such as Fixed Transmission Rights, market monitoring and resource adequacy. Post-blackout reliability concerns were also a stated factor for the withdrawal. On October 29, 2003, FERC granted the MISO's motion. The MISO had planned to phase-in its energy markets during 2004. The withdrawal of the market tariff means that the market will be delayed for an undetermined period of time. The delay will have the potential to impact NRG Energy's Illinois generating facilities.

On October 28, 2003, FERC issued an order conceptually approving the proposed re-design of the California ISO market, which has the potential to impact NRG Energy's California interests.

17. Asset Retirement Obligation

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

NRG Energy has identified certain retirement obligations within its power generation operations related to its North America projects in the South Central region, the Northeast region and the Mid Atlantic region, its Alternative Energy projects and its Thermal projects. These asset retirement obligations are related primarily to the future dismantlement of equipment on leased property and environment obligations related to ash disposal site closures. NRG Energy has also identified other asset retirement obligations that could not be calculated because the assets associated with the retirement obligations were determined to have an indeterminate life. The 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 a $0.6 million increase to depreciation expense and a $1.6 million increase to cost of majority-owned operations.

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 nine months ended September 30, 2003, which is included in other long-term obligations in the consolidated balance sheet:

Description	Beginning Balance Jan. 1, 2003	Accretion for Nine Month Ended September 30, 2003	Ending Balance September 30, 2003
		(In thousands)	
South Central Region	$ 396	$ 45	$ 441
Northeast Region	313	32	345
Mid Atlantic Region	1,732	186	1,918
Alternative Energy	629	59	688
Thermal	1,171	75	1,246
Total	$ 4,241	$ 397	$ 4,638

The following represents the pro-forma effect on NRG Energy's net income for the three and nine months ended September 30, 2002, as if NRG Energy had adopted SFAS No. 143 as of January 1, 2002:

	Three Months Ended September 30, 2002
	(In thousands)
Loss from continuing operations as reported	$ (2,468,936)
Pro-forma adjustment to reflect retroactive adoption of SFAS No. 143	(171)
Pro-forma loss from continuing operations	$ (2,469,107)
Net loss as reported	$ (3,055,394)
Pro-forma adjustment to reflect retroactive adoption of SFAS No. 143	(171)
Pro-forma net loss	$ (3,055,565)

	Nine Months Ended September 30, 2002
	(In thousands)
Loss from continuing operations as reported	$ (2,527,639)
Pro-forma adjustment to reflect retroactive adoption of SFAS No. 143	(1,980)
Pro-forma loss from continuing operations	$ (2,529,619)
Net loss as reported	$ (3,123,209)
Pro-forma adjustment to reflect retroactive adoption of SFAS No. 143	(1,980)
Pro-forma net loss	$ (3,125,189)

18. Recent Accounting Pronouncements

In April 2002, the FASB issued SFAS No. 145, *"Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections",* that supersedes previous guidance for the reporting of gains and losses from extinguishment of debt and accounting for leases, among other things.

SFAS No. 145 requires that only gains and losses from the extinguishment of debt that meet the requirements for classification as "Extraordinary Items," as prescribed in Accounting Practices Board Opinion No. 30, should be disclosed as such in the financial statements. Previous guidance required all gains and losses from the extinguishment of debt to be classified as "Extraordinary Items." This portion of

SFAS No. 145 is effective for fiscal years beginning after May 15, 2002, with restatement of prior periods required.

In addition, SFAS No. 145 amends SFAS No. 13, *"Accounting for Leases",* as it relates to accounting by a lessee for certain lease modifications. Under SFAS No. 13, if a capital lease is modified in such a way that the change gives rise to a new agreement classified as an operating lease, the assets and obligation are removed, a gain or loss is recognized and the new lease is accounted for as an operating lease. Under SFAS No. 145, capital leases that are modified so the resulting lease agreement is classified as an operating lease are to be accounted for under the sale-leaseback provisions of SFAS No. 98, *"Accounting for Leases".* These provisions of SFAS No. 145 are effective for transactions occurring after May 15, 2002.

SFAS No. 145 will be applied as required. Adoption of SFAS No. 145 is not expected to have a material impact on NRG Energy.

In June 2002, the FASB issued SFAS No. 146, *"Accounting for Costs Associated with Exit or Disposal Activities,"* (SFAS No. 146). SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, *"Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)."* SFAS No. 146 applies to costs associated with an exit activity that does not involve an entity newly acquired in a business combination or with a disposal activity covered by SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets."* The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. SFAS No. 146 will be applied as required.

In January 2003, the FASB issued FASB Interpretation No. 46, *"Consolidation of Variable Interest Entities",* (FIN No. 46). FIN No. 46 requires an enterprise's consolidated financial statements to include subsidiaries in which the enterprise has a controlling interest. Historically, that requirement has been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise's consolidated financial statements do not include the consolidation of variable interest entities with which it has similar relationships but no majority voting interest. Under FIN No. 46 the voting interest approach is not effective in identifying controlling financial interest. The new rule requires that for entities to be consolidated that those assets be initially recorded at their carrying amounts at the date the requirements of the new rule first apply. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value the first date the new rule applies. Any difference between the net amounts of any previously recognized interest in the newly consolidated entity should be recognized as the cumulative effect of an accounting change. FIN No. 46 becomes effective in the first interim or annual period ending after December 15, 2003. FIN No. 46 will be applied as required and is not expected to have a material impact on NRG Energy.

In April 2003, the FASB issued SFAS No. 149, *"Amendment of Statement 133 on Derivative Instruments and Hedging Activities", (SFAS No. 149).* SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under FASB Statement No. 133, *"Accounting for Derivative Instruments and Hedging Activities".* The provisions of SFAS No. 149 are effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. In addition, provisions of SFAS 149 that relate to SFAS Statement No. 133 Implementation Issues that have been effective for fiscal quarters that began prior to June 15, 2003, should continue to be applied in accordance with their respective effective dates. SFAS No. 149 has not had an impact on NRG Energy.

In May 2003, the FASB issues SFAS No. 150, *"Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity", (SFAS No. 150).* SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. The provisions of SFAS 150 are effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. SFAS No. 150 has not had an impact on NRG Energy.

20. Adjustments to Previously Issued Financial Statements

Subsequent to the issuance of NRG Energy's financial statements for the quarter ended September 30, 2002, NRG Energy's management determined that the accounting for certain transactions required restatement.

NRG Energy determined that it had misapplied the provisions of SFAS No. 144 related to asset groupings in connection with the review for impairment of its long-lived assets during the quarter ended September 30, 2002. SFAS No. 144 requires that for purposes of testing recoverability, assets be grouped at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets. NRG Energy recalculated the asset impairment tests in accordance with SFAS No. 144 using the appropriate asset groupings for independent cash flows for each generation facility. As a result, NRG Energy concluded that asset impairments should have been recorded for two projects known as Bayou Cove Peaking Power LLC and Somerset Power LLC. Since NRG Energy concluded that the triggering events that led to the impairment charge were experienced in the third quarter of 2002, the asset impairments related to these projects should have been recorded as of September 30, 2002. NRG Energy calculated the asset impairment charges for Bayou Cove Peaking Power LLC and Somerset Power LLC to be $126.5 million and $49.3 million, respectively.

In connection with NRG Energy's 2002 year-end audit, two additional items were found to be inappropriately recorded as of September 30, 2002. These items included the inappropriate treatment of interest rate swap transactions as cash flow hedges and the decrease in the value of a bond remarketing option from the original price paid by NRG Energy. The error correction for the interest rate swaps resulted in the recording of additional income of $61.6 million as of September 30, 2002. The recognition of the decrease in the value of the remarketing option resulted in a charge to income of $15.9 million as of September 30, 2002.

A summary of the significant effects of the restatement on our consolidated statements of operations for the three and nine months ended September 30, 2002 is as follows:

	Previously Reported**		As Restated	
	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended
	(In thousands)			
Consolidated Statements of Operations:				
Revenue and equity earnings	$ 653,272	$ 1,671,775	$ 653,272	$ 1,671,775
Operating income	(2,314,505)	(2,210,479)	(2,506,198)	(2,402,172)
Net loss from continuing operations	(2,338,856)	(2,397,559)	(2,468,936)	(2,527,639)
Net loss from discontinued operations	(586,458)	(595,570)	(586,458)	(595,570)
Net loss	(2,925,314)	(2,993,129)	(3,055,394)	(3,123,209)

** As reclassified for discontinued operations.

In addition, the restatement for Bayou Cove Peaking LLC and Somerset Power LLC impairments reduced the previously reported net property, plant and equipment balance by $175.8 million. The restatement for the interest rate swaps had no impact on total shareholder's equity and the restatement for the remarketing option reduced other assets by $15.9 million.

21. Subsequent Event— NRG Energy Bankruptcy Filing

On May 14, 2003, NRG and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. On that date, we filed a plan of reorganization providing for the reorganization of five of the debtors: NRG Energy, Inc., NRG Power Marketing Inc., NRG Capital LLC, NRG Finance Company I LLC (NRG FinCo) and NRGenerating Holdings (No. 23) B.V. (collectively the NRG Plan Debtors). No NRG Energy international operations were included in the filing. The plan of reorganization for the NRG Plan Debtors (the NRG plan of reorganization) generally provides for the elimination of 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, up to $540.0 million in cash and $500.0 million of new debt among our unsecured creditors.

On September 17, 2003, a plan of reorganization was filed for (i) NRG Northeast Generating LLC and its debtor subsidiaries (collectively NRG Northeast) (ii) NRG South Central Generating LLC and its debtor subsidiaries (collectively NRG South Central) and (iii) Berrians I Gas Turbine Power LLC (Berrians and, collectively with NRG Northeast and NRG South Central the Northeast/ South Central Debtors). The plan of reorganization for the Northeast/ South Central Debtors (the Northeast/ South Central plan of reorganization) generally provides for payment in full to holders of allowed secured claims in cash on or around the effective date of the Northeast/ South Central plan of reorganization. Holders of allowed general unsecured claims will receive either (i) cash equal to the unpaid portion of their allowed unsecured claim, (ii) treatment that leaves unaltered the legal, equitable and contractual rights to which such unsecured claim entitles the holder of such claim, (iii) treatment that otherwise renders such unsecured claim unimpaired pursuant to section 1124 of the bankruptcy code or (iv) such other, less favorable treatment that is confirmed in writing as being acceptable to such holder and to the applicable debtor.

An order confirming the NRG plan of reorganization was entered by the bankruptcy court on November 24, 2003 and NRG Energy anticipates the plan will become effective on or about December 5, 2003. On November 25, 2003, an order confirming the Northeast/ South Central plan of reorganization was entered by the bankruptcy court and NRG Energy anticipates that the Northeast/ South Central plan of reorganization will become effective in late 2003 or early 2004.