PROSPECTUS

28,170,000 SHARES

NRG ENERGY, INC.
COMMON STOCK

[NRG LOGO]

$15.00 PER SHARE

NRG Energy, Inc. is selling 28,170,000 shares of its common stock. The underwriters named in this prospectus may purchase up to 4,225,500 additional shares of common stock from us under certain circumstances.

This is an initial public offering of common stock. The common stock has been approved for listing on the New York Stock Exchange under the symbol "NRG."

The shares of common stock being sold will have one vote per share. The shares of class A common stock held by our parent company, Northern States Power Company, are identical to shares of common stock except that they have 10 votes per share. Upon completion of this offering, Northern States Power will control approximately 98% of the combined voting power of our common stock and class A common stock.

INVESTING IN THE COMMON STOCK INVOLVES CERTAIN RISKS. SEE "RISK FACTORS" BEGINNING ON PAGE 7.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

	PER SHARE	TOTAL
Public Offering Price	$15.00	$422,550,000
Underwriting Discount	$ 0.90	$ 25,353,000
Proceeds to NRG Energy, Inc. (before expenses)	$14.10	$397,197,000

The underwriters are offering the shares subject to various conditions. The underwriters expect to deliver the shares to purchasers on or about June 5, 2000.

SALOMON SMITH BARNEY

CREDIT SUISSE FIRST BOSTON

ABN AMRO ROTHSCHILD
A DIVISION OF ABN AMRO
INCORPORATED

BANC OF AMERICA SECURITIES LLC

GOLDMAN, SACHS & CO.

LEHMAN BROTHERS

MERRILL LYNCH & CO.

INSIDE FRONT COVER PAGE -- DESCRIPTION OF ARTWORK

NRG logo appears at the top center of the page.

Underneath the NRG logo, text in the center of the page reads: "We are a leading global energy company engaged in the acquisition, development, ownership and operation of power generation facilities."

At the bottom center of the page is a bar chart depicting megawatt growth between the years 1996 and 2000.

INSIDE COVER GATEFOLD -- DESCRIPTION OF ARTWORK

In the center of the page appears a map of the United States with the location of our facilities noted on the map.

To the left of the United States map appears the following list of project names and locations: "El Segundo Power", "Encina", "Long Beach Generating", "Crockett Cogeneration", "San Diego Turbines", Artesia (California Cogen)", "Mt. Poso", " "San Joaquin Valley Energy" and "Jackson Valley Energy."

Underneath the United States Map appears the following list of project names and locations: "South Central Region", "Louisiana Generating", "Rocky Road", "Morris Cogen", "Cogen America Pryor" and "Power Smith Cogeneration."

To the right of the United States map appears the following list of project names and locations: "Oswego", "Middletown", "Arthur Kill", "Huntley", "Astoria Gas Turbines", "Dunkirk", "Montville", "Devon", "Norwalk", "Somerset Power", "Connecticut Remote Jets", "Kingston Cogeneration", "Parlin Cogen", "Cadillac", "Grays Ferry Cogen", "Newark Cogen", "Penobscot Energy Recovery", "Curtis-Palmer Hydroelectric", "Philadelphia Cogen", "Maine Energy Recovery" and "Turners Falls."

At the bottom left corner of the page appears a map of Australia with the location of our facilities noted on the map.

To the left of the Australia map appears the following list of project names and locations: "Gladstone Power Station", "Loy Yang Power A" and "Collinsville."

At the bottom right of the page appears a map of Europe with the location of our facilities noted on the map.

To the left of the Europe map appears the following list of project names and locations: "Killingholme", "Schkopau", "ECK Generating", "Enfield Energy Centre", "MIBRAG" and "Energy Center Kladno."

YOU SHOULD RELY ONLY ON INFORMATION CONTAINED IN THIS PROSPECTUS. NRG ENERGY, INC. HAS NOT AUTHORIZED ANYONE TO PROVIDE YOU WITH DIFFERENT INFORMATION. NRG ENERGY, INC. IS NOT MAKING AN OFFER OF THESE SECURITIES IN ANY STATE WHERE THE OFFER IS NOT PERMITTED. YOU SHOULD NOT ASSUME THAT THE INFORMATION PROVIDED BY THIS PROSPECTUS IS ACCURATE AS OF ANY DATE OTHER THAN THE DATE ON THE FRONT OF THIS PROSPECTUS.

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SUMMARY

The following summary is qualified in its entirety by, and should be read together with, the more detailed financial and other information included in this prospectus. All of the following information reflects our recapitalization, to be effective immediately prior to this offering, and assumes that the underwriters have not exercised their option to purchase an additional 4,225,500 shares of common stock within 30 days of the date of this prospectus. Before you invest in our common stock, you should consider carefully the information contained in the section entitled "Risk Factors," beginning on page 7.

NRG ENERGY, INC.

NRG Energy, Inc. is a leading global energy company primarily engaged in the acquisition, development, ownership and operation of power generation facilities and the sale of energy, capacity and related products. We believe we are one of the three largest independent power generation companies in the United States and the sixth largest independent power generation company in the world, measured by our net ownership interest in power generation facilities. We own all or a portion of 57 generation projects that have a total generating capacity of 23,660 megawatts ("MW"); our net ownership interest in those projects is 13,664 MW. Upon the closing of our pending acquisition from Conectiv of interests in six power generation facilities, which we expect to occur later this year, we will have interests in projects having a total generating capacity of 28,722 MW; our net ownership interest in those projects will be 15,539 MW. In addition, we have an active acquisition and development program through which we are pursuing additional generation projects.

As the following table illustrates, we have grown significantly during the last three years, primarily as a result of our success in acquiring domestic power generation facilities:

	YEAR ENDED DECEMBER 31,		
	1997	1998	1999
Net Ownership Interest (in MW at year end)	2,637	3,300	10,990
Operating Income (in thousands)	$18,109	$57,012	$109,520

We intend to continue our growth through a combination of targeted acquisitions in selected core markets, the expansion or repowering of existing facilities and the development of new greenfield projects. To prepare for expansion, repowering and greenfield opportunities, we have recently agreed to purchase 16 turbine generators from GE Power Systems and two turbine generators from Siemens Westinghouse over a six year period commencing in 2001. These new turbines, which we expect to install at domestic facilities, will have a combined generating capacity of approximately 3,300 MW.

In addition to our power generation projects, we also have interests in district heating and cooling systems and steam transmission operations. Our thermal and chilled water businesses have a steam and chilled water capacity equivalent to approximately 1,204 MW. We believe that through our subsidiary NEO Corporation we are one of the largest landfill gas generation companies in the United States, extracting methane from landfills to generate electricity. NEO owns 30 landfill gas collection systems and has 55 MW of net ownership interests in related electric generation facilities. NEO also has 35 MW of net ownership interests in 18 small hydroelectric facilities.

MARKET OPPORTUNITY

The power industry is one of the largest industries in the world, accounting for approximately $200 billion in annual revenues and having approximately 800,000 MW of installed generating capacity in the United States alone. The generation segment of the industry historically has been characterized by regulated electric utilities producing and selling electricity to a captive customer base. However, the power generation market has been evolving from a regulated market based upon cost of service pricing to a non-

regulated competitive market. We believe that the power industry will continue to undergo substantial restructuring over the next several years and will experience significant growth in the future.

As of January 2000, 22 states had enacted legislation to restructure their electric utility industries, four additional state public utility commissions had issued comprehensive restructuring orders and 20 additional states had active legislative or regulatory processes underway to study restructuring and propose implementing legislation. As a result, from January 1, 1997 through December 31, 1999, approximately 70,000 MW of the power generating capacity in the United States had been sold or transferred by regulated electric utilities to independent power producers. We expect in excess of 70,000 MW of additional power generating capacity to be sold to independent power producers by the end of 2002.

We believe that increasing demand and the need to replace old and inefficient generation facilities will create a significant need for additional power generating capacity throughout the United States. In our view, these factors combined with recent restructuring legislation provide an attractive environment in the United States for an independent power producer like us with a history of successfully developing, acquiring and operating power generation facilities.

Outside of the United States, many governments in developed economies are privatizing their utilities and developing regulatory structures that are expected to encourage competition in the electricity sector, having realized that their energy assets can be sold to raise capital without hindering system reliability. In developing countries, the demand for electricity is expected to grow rapidly. In order to satisfy this anticipated increase in demand, many countries have adopted active government programs designed to encourage private investment in power generation facilities. We believe that these market trends will continue to create opportunities to acquire and develop power generation facilities globally.

STRATEGY

Our vision is to be a well-positioned, top three generator of power in selected core markets. Central to this vision is the pursuit of a well-balanced generation business diversified in terms of geographic location, fuel type and dispatch level. Currently, 80% of our generation is located in the United States in three core markets: our Northeast, South Central and West Coast regions. With our diversified asset base, we seek to have generating capacity available to back up any given facility during its outages, whether planned or unplanned, while having ample resources to take advantage of peak power market price opportunities and periods of constrained availability of generating capacity, fuels and transmission.

The following charts illustrate our diversity:

GEOGRAPHIC LOCATION(1)

U.S.	EUROPE	AUSTRALIA	OTHER
80	9.00	10.00	1.00

PRIMARY FUEL TYPE(1)(2)

COAL	GAS	OIL	OTHER
35	37	26	2

DISPATCH LEVEL(3)

PEAKING	INTERMEDIATE	BASE-LOAD
41	19	40

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(1) Based upon MW of net ownership interest as of March 31, 2000.

(2) Several of our generation facilities, constituting approximately 3,900 MW of generating capacity, are capable of utilizing more than one fuel, which can be switched as fuel prices fluctuate.

(3) Estimated for 2000 based upon historic dispatch data. We define "base-load" as facilities that we expect to operate greater than 60% of the year, "intermediate" as facilities that we expect to operate between 20% and 60% of the year and "peaking" as facilities that we expect to operate less than 20% of the year, assuming utilization of primary fuel type.

Our strategy is to capitalize on our acquisition, development and operating skills to build a balanced, global portfolio of power and thermal generation assets. We intend to implement this strategy by continuing an aggressive but thoughtful acquisition program and accelerating our development of existing site expansion projects and greenfield projects. We believe that our operational skills and experience give us a strong competitive position in the unregulated generation marketplace.

We have organized our operations geographically such that inventories, maintenance, backup power supply and other operational functions are pooled within a region. This approach enables us to realize cost savings and enhances our ability to meet our facility availability goals. Our availability goals are not driven by traditional benchmarks, such as daily or annual availability, but are focused on each facility's availability during periods when power prices are significantly above the variable cost of producing power at that facility -- what we call "in-market" availability.

By leveraging the talents of our regional management teams, focusing on our regional market expertise and operating experience and utilizing our asset base on a regional rather than a project basis, we believe we can best position ourselves for long term profitability. Achieving "critical mass" in core markets should allow us to capitalize on opportunities available in those markets.

We do not own nor do we have any present intention to own any interest in nuclear generation facilities.

Domestic. We intend to focus our near-term domestic development and acquisition plans on our existing three core markets, our Northeast, South Central and West Coast regions, and to add the Mid-Atlantic region as our fourth core market upon the closing of our planned acquisition from Conectiv. We will consider domestic projects outside of these markets if we believe that an opportunity exists to create a new core market or that the projected returns from a particular project warrant an investment.

International. Based upon our assessment of market opportunities and our portfolio risk management criteria, we intend to leverage our reputation, experience and expertise in order to acquire foreign assets in selected countries. We are presently focusing our international development and acquisition activities in the United Kingdom, Central Europe, Turkey, Australia and, to a lesser extent, Latin America. In the future, we will consider other areas that are consistent with our strategy.

RECENT DEVELOPMENTS

TURBINE ACQUISITIONS

In February 2000, we executed a memorandum of understanding with GE Power Systems, a division of General Electric Company, to purchase 11 gas turbine generators and five steam turbine generators, with an option to purchase additional units. The purchases will take place over the next five years with the first delivery scheduled to be made in 2002. The 16 turbines will have an equivalent generation output of approximately 3,000 MW and an acquisition cost of approximately $500 million.

In March 2000, we entered into an agreement with Great River Energy under which Great River assigned to us all of its rights and obligations with respect to two 135 MW turbines being built for it by Siemens Westinghouse. Our total cost for the turbines, which are scheduled for delivery in the first or second quarter of 2001, will be approximately $43 million.

We expect to install the turbines described above at existing plant sites in the United States as well as new greenfield sites.

RECENT AND PENDING GENERATION ACQUISITIONS

CAJUN FACILITIES

In March 2000, we acquired 1,708 MW of coal and gas-fired generation assets in Louisiana for approximately $1,026 million. These assets were formerly owned by Cajun Electric Power Cooperative, Inc., and we refer to them as the "Cajun facilities." We sell a significant amount of the energy and capacity of the Cajun facilities to 11 of Cajun Electric's former power cooperative members. Seven of these cooperatives have entered into 25-year power purchase agreements with us, and four have entered into two to four year power purchase agreements. In addition, we sell power under contract to two municipal power authorities and one investor-owned utility that were former customers of Cajun Electric. We estimate that payments under the contracts with the 11 cooperatives will account for approximately 72% of the Cajun facilities' projected 2001 revenues, and that payments under the contracts with the municipal power authorities and the investor-owned utility will account for approximately an additional 7% of such revenues.

Due to lower than anticipated financial performance from the Cajun facilities including higher than expected costs associated with a scheduled outage at one of Cajun's units, our net income was negatively impacted by $6.3 million for April 2000. While we do not expect our or Cajun's overall results for the year 2000 to be negatively impacted as a result of these issues, we currently expect our second quarter results to be negatively impacted by these issues relative to prior expectations.

KILLINGHOLME FACILITY

In March 2000, we acquired the Killingholme A generation facility from National Power plc for L390 million (approximately $615 million at the time of the acquisition), subject to post-closing adjustments. Killingholme is a combined cycle gas-fired baseload facility located in North Lincolnshire, England. The facility comprises three units with a total generating capacity of 680 MW. We own and operate the facility, which sells its power into the wholesale electricity market of England and Wales.

CONNECTICUT FACILITIES

In December 1999, we acquired four gas and oil-fired electric generation facilities and six remote oil-fired turbine facilities from Connecticut Light & Power Company for approximately $519 million. These facilities are located throughout Connecticut and have a combined generating capacity of 2,235 MW. In October 1999, we entered into a four-year standard offer service wholesale sales agreement with Connecticut Light & Power pursuant to which we are obligated to supply at fixed prices a portion of its aggregate retail load. The quantity of power to be supplied is equal to 35% of Connecticut Light & Power's standard offer service load during calendar year 2000, 40% during calendar years 2001 and 2002, and 45% during calendar year 2003. We estimate that 45% of Connecticut Light & Power's standard offer service load in 2003 will be approximately 2,000 MW at peak requirement.

CONECTIV FACILITIES

In January 2000, we executed purchase agreements with subsidiaries of Conectiv to acquire 1,875 MW of coal, gas and oil-fired electric generating capacity and other assets. We will pay approximately $800 million for the assets, a portion of which will be financed by project-level debt. The assets include the BL England and Deepwater facilities in New Jersey, the Indian River facility in Delaware and the Vienna facility in Maryland, and interests in the Conemaugh (7.6%) and Keystone (6.2%) facilities in Pennsylvania. The purchase also includes excess emission allowances. Subject to receipt of required regulatory approvals, we expect the acquisition to close in the fourth quarter of 2000. Subject to final documentation, we will sell 500 MW of capacity and associated energy to a subsidiary of Conectiv under a five-year power purchase agreement commencing upon the closing of the acquisition.

PROPOSED MERGER OF NORTHERN STATES POWER COMPANY

We have been acquiring and developing power generation projects since 1989, when we were formed as a wholly-owned subsidiary of Northern States Power Company, an investor-owned utility that serves customers in the upper Midwest and owns and operates approximately 7,100 MW of generating capacity. On March 24, 1999, Northern States Power and New Century Energies, Inc., a Colorado-based public utility holding company, entered into an agreement providing for the merger of the two companies. Following the merger, Northern States Power's utility assets will be held in a subsidiary of the surviving corporation in the merger, which will be renamed "Xcel Energy, Inc.", and the shares of our class A common stock that will be owned by Northern States Power will be transferred to a wholly-owned subsidiary of Xcel Energy. The merger has been approved by the shareholders of both companies and by the Federal Energy Regulatory Commission, but remains subject to standard closing conditions and other regulatory approvals. It is currently expected that the merger will be completed in the second or third quarter of 2000.

CORPORATE INFORMATION

We are incorporated in Delaware and our headquarters and principal executive offices are located at 1221 Nicollet Mall, Suite 700, Minneapolis, Minnesota 55403. Our telephone number is (612) 373-5300.

THE OFFERING

Common stock offered by NRG...	28,170,000 shares(1)
Common stock to be outstanding after the offering....................	28,170,000 shares(1)(2)
Class A common stock to be outstanding after the offering....................	147,604,500 shares(3)
Total common stock and class A common stock to be outstanding after the offering....................	175,774,500 shares(1)(2)
Use of proceeds..............	To repay $300 million of indebtedness owed to Citicorp USA, Inc. Remaining proceeds will be used for general corporate purposes, including working capital, capital expenditures and business acquisitions. None of the proceeds will be distributed to Northern States Power. See "Use of Proceeds."
Listing......................	NYSE
Proposed symbol..............	"NRG"

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(1) Excludes 4,225,500 shares of common stock that the underwriters have an option to purchase from us within 30 days of the date of this prospectus.

(2) Excludes approximately 4,400,000 shares issuable upon the exercise of stock options granted to our employees and non-employee directors under the NRG 2000 Long-Term Incentive Compensation Plan.

(3) Shares of class A common stock have 10 votes per share and are convertible on a share-for-share basis into shares of common stock. Shares of common stock have one vote per share. In all other respects, shares of class A common stock and shares of common stock have identical rights and privileges. All outstanding shares of class A common stock will be held by Northern States Power.

SUMMARY CONSOLIDATED FINANCIAL AND OPERATING DATA

The summary historical financial data set forth below as of December 31, 1997, 1998 and 1999, and for the years then ended, have been derived from our audited consolidated financial statements. The financial data set forth below as of March 31, 2000, and for the three-month periods then ended, have been derived from our unaudited financial statements, which were prepared on a basis consistent with our audited consolidated financial statements. We have supplied the selected capacity data set forth below under the caption "Other Generation Data." All amounts are set forth in thousands, except for net ownership interest and per share amounts.

	YEAR ENDED DECEMBER 31,	THREE MONTHS ENDED MARCH 31,

	1997	1998	1999	PRO FORMA 1999(1)	2000	PRO FORMA 2000(1)
CONSOLIDATED INCOME STATEMENT DATA						
Revenues from wholly-owned operations............	$ 92,052	$ 100,424	$ 432,518	$ 801,080	$332,671	$412,653
Equity in earnings of unconsolidated affiliates...	26,200	81,706	67,500	67,500	(9,644)	(9,644)
Operating income (loss)..........................	18,109	57,012	109,520	189,665	62,937	74,811
Other income (expense)(2)........................	11,371	9,379	14,970	13,100	(267)	254
Interest expense.................................	(30,989)	(50,313)	(93,376)	(166,624)	(52,317)	(70,629)
Income tax (benefit) expense(3)..................	(23,491)	(25,654)	(26,081)	(24,001)	1,607	(841)
Net income (loss)................................	$ 21,982	$ 41,732	$ 57,195	$ 60,142	$ 8,746	$ 5,277
Earnings per share -- basic and diluted..........	$ .15	$ .28	$ .39	$ .41	$ .06	$ .04
Weighted average shares outstanding -- basic and diluted..	147,605	147,605	147,605	147,605	147,605	147,605

	AS OF DECEMBER 31, 1997	1998	1999	AS OF MARCH 31, 2000
CONSOLIDATED BALANCE SHEET DATA				
Net property, plant and equipment...............	$ 185,891	$ 204,729	$1,975,403	$3,669,654
Total assets....................................	1,168,102	1,293,426	3,431,684	5,293,808
Long-term recourse debt, including current maturities....................................	499,982	504,781	915,000	1,169,608
Long-term non-recourse debt, including current maturities............................	120,873	121,695	1,056,860	2,325,677
Stockholder's equity............................	450,698	579,332	893,654	872,120

	AS OF DECEMBER 31, 1997	1998	1999	AS OF MARCH 31, 2000
OTHER GENERATION DATA				
Net ownership interest (MW).....................	2,637	3,300	10,990	13,664

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(1) The pro forma financial information gives effect to our March 31, 2000 acquisition of the Cajun facilities as if that acquisition had occurred on January 1, 1999. We do not believe that the pro forma data is indicative of our future revenues and earnings, because the previous owner of the Cajun facilities sold energy and capacity and purchased coal upon terms substantially different from those under which we will operate these facilities. Thus, we believe the pro forma financial information is of limited use in making an investment decision.

(2) These amounts include pretax charges of $9.0 million in 1997, $26.7 million in 1998 and $0 in 1999 to write down the carrying value of certain energy projects. These amounts also include the pre-tax gain on sale of our interest in projects of $8.7 million in 1997, $30.0 million in 1998 and $15.5 million in 1999.

(3) We have substantial tax credits that can be utilized by Northern States Power. Northern States Power pays us for these tax credits on a quarterly basis.

RISK FACTORS

Before you invest in our common stock, you should be aware of the significant risks described below. You should carefully consider these risks, together with all of the other information included in this prospectus, before you decide whether to purchase shares of our common stock.

Some of the information in this prospectus contains forward-looking statements that involve substantial risks and uncertainties. You can identify these statements by forward-looking words such as "may," "will," "expect," "anticipate," "believe," "estimate" and "continue" or similar words. You should read statements that contain these words carefully because they: (1) discuss our future expectations; (2) contain projections of our future results of operations or of our future financial condition; or (3) state other "forward-looking" information. We believe that it is important to communicate our future expectations to our investors. However, our future results and financial condition will be impacted by events or factors in the future that we have not been able to accurately predict or over which we have no control.

The risk factors listed in this section, as well as any cautionary language in this prospectus, provide examples of risks, uncertainties and events that may cause our actual results to differ materially from the expectations we describe in our forward-looking statements. Before you invest in our common stock, you should be aware that the occurrence of the events described in these risk factors and elsewhere in this prospectus could have a material adverse effect on our business, financial condition and results of operations and on the price of our common stock.

RISKS RELATING TO THE WHOLESALE POWER MARKETS

OUR REVENUES ARE NOT PREDICTABLE BECAUSE MANY OF OUR POWER GENERATION FACILITIES OPERATE, WHOLLY OR PARTIALLY, WITHOUT LONG-TERM POWER PURCHASE AGREEMENTS.

Historically, substantially all revenues from independent power generation facilities were derived under power purchase agreements having terms in excess of 15 years, pursuant to which all energy and capacity was generally sold to a single party at fixed prices. Because of changes in the industry, the percentage of facilities, including ours, with these types of long-term power purchase agreements has decreased, and it is likely that over time, most of our facilities will operate without these agreements. Without the benefit of these types of power purchase agreements, we cannot assure you that we will be able to sell the power generated by our facilities or that our facilities will be able to operate profitably.

BECAUSE WHOLESALE POWER PRICES ARE SUBJECT TO EXTREME VOLATILITY, THE REVENUES THAT WE GENERATE ARE SUBJECT TO SIGNIFICANT FLUCTUATIONS.

We must sell all or a portion of the energy, capacity and other products from many of our facilities into 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 in those markets. In addition, unlike most other commodities, energy products cannot be stored and therefore must be produced concurrently with their use. As a result, the wholesale power markets are subject to significant price fluctuations over relatively short periods of time and can be unpredictable.

WE HAVE A LIMITED HISTORY OF SELLING AND MARKETING PRODUCTS IN THE WHOLESALE POWER MARKETS AND MAY NOT BE ABLE TO SUCCESSFULLY MANAGE THE RISKS ASSOCIATED WITH THIS ASPECT OF OUR BUSINESS.

We are exposed to market risks through our power marketing business, which involves the establishment of trading positions in the energy, fuel and emission allowance markets on a short-term basis. We sell forward contracts and options and establish positions in, and sell on the spot market, our energy, capacity and other energy products that are not otherwise committed under long-term contracts. In addition, we use these trading activities to procure fuel and emission allowances for our facilities on the spot market. We have been managing risks associated with price volatility in this manner for only a limited amount of time. We may not be able to effectively manage this price volatility, and may not be able to successfully manage the other risks associated with trading in energy markets, including the risk that counter parties may not perform.

RISKS RELATING TO OUR OPERATIONS

WE HAVE MADE SUBSTANTIAL INVESTMENTS IN OUR RECENT ACQUISITIONS AND OUR SUCCESS DEPENDS ON THE APPROPRIATENESS OF THE PRICES WE PAID IN THESE ACQUISITIONS AS WELL AS ON OUR ABILITY TO SUCCESSFULLY INTEGRATE, OPERATE AND MANAGE THE ACQUIRED ASSETS.

During the period from December 31, 1998 through March 31, 2000, we have more than quadrupled our net ownership interests in power generation facilities, expanding from 3,300 MW of net ownership interests in power generation facilities to approximately 13,664 MW of net ownership interests. During the rest of this year, if we complete the pending acquisition from Conectiv, we will increase our net ownership interests in power generation facilities by an additional 14%. The prices we paid in these acquisitions were based on our assumptions as to the economics of operating the acquired facilities and the prices at which we would be able to sell energy, capacity and other products from them. If any of the assumptions as to a given facility prove to be materially inaccurate, it could have a significant impact on the financial performance of that facility and possibly on our entire company. In connection with these acquisitions, we have hired and will hire a substantial number of new employees. We may not be able to successfully integrate all of the newly hired employees, or profitably integrate, operate, maintain and manage our newly acquired power generation facilities in a competitive environment. In addition, operational issues may arise as a result of a lack of integration or our lack of familiarity with issues specific to a particular facility.

OUR PROJECT DEVELOPMENT AND ACQUISITION ACTIVITIES MAY NOT BE SUCCESSFUL WHICH WOULD IMPAIR OUR ABILITY TO EXECUTE OUR GROWTH STRATEGY.

We may not be able to identify attractive acquisition or development opportunities or to complete acquisitions or development projects that we undertake. If we are not able to identify and complete additional acquisitions and development projects, we will not be able to successfully execute our growth strategy. Factors that could cause our acquisition and development activities to be unsuccessful include the following:

- competition,

- inability to obtain additional capital on acceptable terms,

- inability to obtain required governmental permits and approvals,

- cost-overruns or delays in development that make continuation of a project impracticable,

- inability to negotiate acceptable acquisition, construction, fuel supply or other material agreements, and

- inability to hire and retain qualified personnel.

WE INCUR SIGNIFICANT EXPENSES IN EVALUATING POTENTIAL PROJECTS, MOST OF WHICH ARE NOT ULTIMATELY ACQUIRED OR COMPLETED.

In order to implement our growth strategy, we must continue to actively pursue acquisition and development opportunities. Substantial expenses are incurred in investigating and evaluating any potential opportunity before we can determine whether the opportunity is feasible or economically attractive. In addition, we expect to participate in many competitive bidding processes for power generation facilities that require us to incur substantial expenses without any assurance that our bids will be accepted. As a result, we expect that our development expenses will increase in the future with no assurance that we will be successful in acquiring or completing additional new projects.

CONSTRUCTION, EXPANSION, REFURBISHMENT AND OPERATION OF POWER GENERATION FACILITIES INVOLVE SIGNIFICANT RISKS THAT CANNOT ALWAYS BE COVERED BY INSURANCE OR CONTRACTUAL PROTECTIONS.

The construction, expansion and refurbishment of power generation, thermal energy production and transmission and resource recovery facilities involve many risks, including:

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

The ongoing operation of these facilities involves all of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes and performance below expected levels of output or efficiency. New plants may employ recently developed and technologically complex equipment, especially in the case of newer environmental emission control technology. 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. 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. As a result, a project may operate at a loss or be unable to fund principal and interest payments under its project financing agreements, which may result in a default under that project's indebtedness.

WE ARE EXPOSED TO THE RISK OF FUEL COST INCREASES AND INTERRUPTION IN FUEL SUPPLY BECAUSE OUR FACILITIES GENERALLY DO NOT HAVE LONG-TERM FUEL SUPPLY AGREEMENTS.

Most of our domestic power generation facilities that sell energy into the wholesale power markets purchase fuel under short-term contracts or on the spot market. Even though we attempt to hedge some portion of our known fuel requirements, we still may face the risk of supply interruptions and fuel price volatility. 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.

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. The failure of any one customer or supplier 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 continued performance by customers and suppliers of their obligations under these long-term agreements and, in particular, on the credit quality of the project's customers and suppliers.

OUR SIGNIFICANT BUSINESS OPERATIONS OUTSIDE THE UNITED STATES EXPOSE US TO LEGAL, TAX, CURRENCY, INFLATION, CONVERTIBILITY AND REPATRIATION RISKS, AS WELL AS POTENTIAL CONSTRAINTS ON THE DEVELOPMENT AND OPERATION OF OUR POTENTIAL BUSINESS, ANY OF WHICH CAN LIMIT THE BENEFITS TO US OF EVEN A

SUCCESSFUL FOREIGN PROJECT.

A key component of our business strategy is the development and acquisition of projects outside the United States in areas such as the United Kingdom, Australia, Central Europe and Latin America. The

economic and political conditions in many of the countries where we have assets or in which we are or may be exploring development or acquisition opportunities present many risks. These risks, such as delays in permitting and licensing, construction delays and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation or nullification of existing contracts and changes in law or tax policy are generally greater than risks in the United States. The uncertainty of the legal environment in certain foreign countries in which we may develop or acquire projects could make it more difficult to obtain non-recourse project financing on suitable terms and could impair our ability to enforce our rights under agreements relating to these projects.

Operations in foreign countries also can present currency exchange, inflation, convertibility and repatriation risks. In countries in which we may develop or acquire projects in the future, economic and monetary conditions and other factors could affect our ability to convert our earnings to United States dollars or other acceptable currencies or to move funds offshore from such countries. Furthermore, the central bank of any foreign country may have the authority in certain circumstances to suspend, restrict or otherwise impose conditions on foreign exchange transactions or to approve distributions to foreign investors. Although we generally seek to structure our power purchase agreements and other project revenue agreements to provide for payments to be made in, or indexed to, United States dollars or a currency freely convertible into United States dollars, we can offer no assurance that we will be able to achieve this structure in all cases or that a power purchaser or other customer will be able to obtain acceptable currency to pay their obligations to us.

As part of privatizations or other international acquisition opportunities, we may make investments in ancillary businesses not directly related to power generation, thermal energy production and transmission or resource recovery and in which our management may not have had prior experience. In such cases, our policy is to invest with partners having the necessary expertise. However, we can offer no assurance that such persons will be available as co-venturers in every case. In addition, as a condition to participating in privatizations and refurbishments of formerly state-owned businesses, we may be required to undertake transitional obligations relating to union contracts, employment levels and benefits obligations for employees, which could prevent or delay the achievement of desirable operating efficiencies and financial performance.

THE LOY YANG FACILITY IN WHICH WE HAVE INVESTED IS EXPERIENCING FINANCIAL DIFFICULTIES BECAUSE OF LOWER THAN EXPECTED WHOLESALE POWER PRICES, WHICH COULD RESULT IN AN EVENT OF DEFAULT UNDER ITS LOAN AGREEMENTS.

Energy prices in the Victoria region of the National Electricity Market of Australia into which our Loy Yang facility sells its power have been significantly lower than we had expected when we acquired our interest in that facility. As a result, the Loy Yang project company is currently prohibited by its loan agreements from making equity distributions to the project owners. Based on our forecasted power prices, we expect that the Loy Yang project company will fail to meet required coverage ratios under its loan agreements beginning in the third quarter of 2001, which constitutes an event of default. Moreover, if market prices in Victoria continue at current levels, which are below our forecasted power prices, we expect that the Loy Yang project company will be unable to service its long-term senior debt obligations beginning in the first quarter of 2002. In either case, absent a restructuring of the project company's debt, the project company's lenders would be allowed to accelerate the project company's indebtedness. We could be required to write off all or a significant portion of our current US$250 million investment in this project as a result of such acceleration, or as a result of a determination by the project company that a write-down of its assets is required or our determination that we would not be able to recover our investment in the project.

RISKS RELATING TO OUR CORPORATE AND FINANCIAL STRUCTURE

BECAUSE WE OWN LESS THAN 100% OF SOME OF OUR PROJECT INVESTMENTS, WE CANNOT EXERCISE COMPLETE CONTROL OVER THEIR OPERATIONS.

We have limited control over the development, construction, acquisition or operation of some project investments and joint ventures because our investments are in projects where we beneficially own less than

50% of the ownership interests. A substantial portion of our future investments in international projects may also take the form of minority interests. We seek to exert a degree of influence with respect to the management and operation of projects in which we own less than 50% 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 construct and operate such projects. Our co-venturers may not have the level of experience, technical expertise, human resources management and other attributes necessary to construct and 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.

WE REQUIRE SIGNIFICANT AMOUNTS OF CAPITAL TO GROW OUR BUSINESS AND OUR FUTURE ACCESS TO SUCH FUNDS IS UNCERTAIN.

We will require continued access to substantial debt and equity capital from outside sources on acceptable terms in order to assure the success of future projects and acquisitions, including the planned Conectiv acquisition. Our ability to arrange debt 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,

- maintenance of acceptable credit ratings,

- the success of current projects,

- the perceived quality of new projects, and

- provisions of tax and securities laws that may impact raising capital in this manner.

In order to access capital on a substantially non-recourse basis in the future, we may have to make larger equity investments in, or provide more financial support for, our project subsidiaries. We also may not be successful in structuring future financing for our projects on a substantially non-recourse basis.

To date, the equity capital for our projects has been provided by equity contributions from Northern States Power, internally-generated cash flow from our projects and other borrowings. We cannot assure you that Northern States Power will continue to provide additional equity capital to us or permit us to raise additional equity capital from others. Any inability to raise additional equity capital will restrict our ability to execute our growth strategy.

WE HAVE SUBSTANTIAL INDEBTEDNESS, WHICH COULD LIMIT OUR ABILITY TO GROW AND OUR FLEXIBILITY IN OPERATING OUR PROJECTS.

As of March 31, 2000, we had total recourse debt of $1,774 million, with an additional $2,325 million of non-recourse debt appearing on our balance sheet. The percentage of our total recourse debt to recourse debt and equity was 67.0% as of March 31, 2000. The substantial amount of debt that we have and the debt of our project subsidiaries and project affiliates presents the risk that we might not generate sufficient cash to service our indebtedness, and that our leveraged capital structure could limit our ability to finance the acquisition and development of additional projects, to compete effectively, to operate successfully under adverse economic conditions and to fully implement our strategy. The terms of our debt and the debt of our project subsidiaries and project affiliates also restrict our flexibility in operating our projects.

In addition, our lenders may accelerate our credit facilities and public debt instruments upon the occurrence of events of default or if we undergo a change of control. Because Northern States Power will control approximately 98% of the total voting power of our common stock and our class A common stock, we will have no ability to prevent a change of control. If our indebtedness is accelerated, we could be forced into bankruptcy, and you could lose your entire investment.

Although we expect that the cash available from our domestic operations and the repayment to us of loans made by us to our foreign affiliates will be sufficient to service our corporate-level indebtedness, there

can be no assurance that these funds will be sufficient to make corporate-level debt payments as and when due. If we elect to repatriate cash from foreign subsidiaries or affiliates to make these payments in case of such a shortfall, then we may incur United States taxes, net of any available foreign tax credits, on the repatriation of such foreign cash.

WE HAVE GUARANTEED OBLIGATIONS AND LIABILITIES OF OUR PROJECT SUBSIDIARIES AND AFFILIATES WHICH WOULD BE DIFFICULT FOR US TO SATISFY IF THEY ALL CAME DUE SIMULTANEOUSLY.

In many of our projects, we have executed guarantees of the project affiliate's indebtedness, equity or operating obligations. In addition, in connection with the purchase and sale of fuel, emission allowances and power generation products to and from third parties with respect to the operation of some of our generation facilities, we are required to guarantee a portion of the obligations of certain of our subsidiaries. These guarantees totaled approximately $504 million as of March 31, 2000. We may not be able to satisfy all of these guarantees and other obligations if they were to come due at the same time, which would have a material adverse effect on us.

OUR HOLDING COMPANY STRUCTURE LIMITS OUR ACCESS TO THE FUNDS OF PROJECT SUBSIDIARIES AND PROJECT AFFILIATES THAT WE WILL NEED IN ORDER TO SERVICE OUR CORPORATE-LEVEL INDEBTEDNESS.

Substantially all of our operations are conducted by our project subsidiaries and project affiliates. Our cash flow and our ability to service our corporate-level indebtedness when due is dependent upon our receipt of cash dividends and distributions or other transfers from our projects and other subsidiaries. The debt agreements of our subsidiaries and project affiliates generally restrict their ability to pay dividends, make distributions or otherwise transfer funds to us. In addition, a substantial amount of the assets of our project subsidiaries and project affiliates has been pledged as collateral under their debt agreements.

Our project subsidiaries and project affiliates are separate and distinct legal entities that have no obligation, contingent or otherwise, to pay any amounts due under our indebtedness or to make any funds available to us, whether by dividends, loans or other payments, and they do not guarantee the payment of our corporate-level indebtedness. We own less than 50% of the ownership interests in many of our foreign projects, and therefore we are unable to unilaterally cause dividends or distributions to be made from these operations.

WE ARE CONTROLLED BY NORTHERN STATES POWER COMPANY. NORTHERN STATES POWER

MAY NOT ALWAYS EXERCISE ITS CONTROL IN A WAY THAT BENEFITS OUR PUBLIC STOCKHOLDERS.

Northern States Power will hold approximately 98% of the total voting power of our common stock and our class A common stock following this offering. Accordingly, without the approval of the holders of our common stock, Northern States Power will be able to control the vote on all matters submitted to a vote of the stockholders and in particular be able to elect all our directors, amend our certificate of incorporation or effect a merger, sale of assets, or other major corporate transaction, defeat any non-negotiated takeover attempt, determine the amount and timing of dividends paid on common stock, and otherwise control our management and operations and the outcome of all matters submitted for a stockholder vote. In circumstances involving a conflict of interest between Northern States Power, as the controlling stockholder, on the one hand, and our other stockholders on the other, we can offer no assurance that Northern States Power would not exercise its power to control us in a manner that would benefit Northern States Power to the detriment of our other stockholders.

In addition, Northern States Power may enter into credit agreements, indentures or other contracts which limit the activities of its subsidiaries. While we would not likely be contractually bound by these limitations, Northern States Power would likely cause its representatives on our board to direct our business so as not to breach any of these agreements.

OUR CERTIFICATE OF INCORPORATION AND BYLAW PROVISIONS, AND SEVERAL OTHER FACTORS, COULD LIMIT ANOTHER PARTY'S ABILITY TO ACQUIRE US AND COULD DEPRIVE YOU OF THE OPPORTUNITY TO OBTAIN A TAKEOVER PREMIUM FOR YOUR SHARES OF COMMON STOCK.

A number of provisions that are in our certificate of incorporation and bylaws will make it difficult for another company to acquire us and for you to receive any related takeover premium for your shares. For example, our certificate of incorporation allows our board of directors to issue up to 200,000,000 preferred shares without a stockholder vote and provides that stockholders may not act by written consent and may not call a special meeting. In addition, our capital structure may deter a potential change in control, because our voting power will be concentrated in our class A common stock.

POTENTIAL CONFLICTS OF INTEREST WITH OUR CONTROLLING STOCKHOLDER MAY BE RESOLVED IN A MANNER THAT IS ADVERSE TO US.

Northern States Power, our controlling stockholder, and directors and officers of Northern States Power and its subsidiaries who may be our directors, are in positions involving the possibility of conflicts of interest with respect to transactions in which both we and Northern States Power have an interest. In addition, Northern States Power, subject to its fiduciary duties owed to our minority stockholders, may compete with us for business opportunities that may be attractive to both us and to Northern States Power. We can offer no assurance that any such conflict will be resolved in our favor.

THE PENDING MERGER OF NORTHERN STATES POWER AND NEW CENTURY ENERGIES WILL CONSTRAIN THE CONDUCT OF OUR BUSINESS.

It is expected that the pending merger of Northern States Power and New Century Energies will be accounted for as a "pooling of interest." In accordance with the "pooling of interest" rules, neither company can alter their equity interests or dispose of a material portion of their assets through the date of the merger and for a period of time thereafter. These constraints may limit our flexibility to conduct our business as we otherwise would absent such constraints.

After the merger, the shares of our class A common stock that are owned by Northern States Power will be owned by a wholly-owned subsidiary of the surviving corporation in the merger, Xcel Energy. Xcel Energy will be subject to the provisions of various energy-related laws and regulations, including the Public Utility Holding Company Act of 1935 ("PUHCA"), and, in turn, we will be subject to constraints imposed by PUHCA. See "Business -- Energy Regulation in the United States".

IF NORTHERN STATES POWER COULD NOT CONSOLIDATE US ON THEIR UNITED STATES FEDERAL INCOME TAX RETURNS, WE COULD LOSE THE REIMBURSEMENT WE RECEIVE FOR TAX BENEFITS.

We are a member of Northern States Power's consolidated tax group for purposes of United States federal income taxes. We have generated significant tax assets in the past from which Northern States Power has been able to benefit. We received, subject to possible adjustment, $13.4 million for the year ended December 31, 1999 for the use of such benefits. If Northern States Power owns common stock or class A common stock representing less than 80% of our voting power, or equity securities representing less than 80% of our value, or cannot generate substantial taxable income to utilize such tax benefits, we will no longer receive a cash reimbursement for these benefits on a dollar-for-dollar basis and we may not be able to use all of the benefits immediately.

MANY OF OUR INCOME TAX REPORTING POSITIONS HAVE NOT BEEN AUDITED AND COULD BE DISALLOWED.

In connection with the preparation of Northern States Power's consolidated income tax returns, we have taken tax positions on many issues, including issues relating to Section 29 tax credits and international tax structures. Although we believe that our reporting positions are correct, many of these returns have not been audited and we cannot assure you that our reporting positions will not be disallowed.

RISKS RELATING TO OUR INDUSTRY

OUR BUSINESS IS SUBJECT TO SUBSTANTIAL GOVERNMENTAL REGULATION AND PERMITTING REQUIREMENTS AND MAY BE ADVERSELY AFFECTED BY ANY FUTURE INABILITY TO COMPLY WITH EXISTING OR FUTURE REGULATIONS OR REQUIREMENTS.

In General. Our business is subject to extensive energy, environmental and other laws and regulations of federal, state and local authorities. We generally are required to obtain and comply with a wide variety of licenses, permits and other approvals in order to operate our facilities. We may incur significant additional costs because of our compliance 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. In addition, existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or our facilities, and future changes in laws and regulation may have a detrimental effect on our business. Furthermore, with the continuing trend toward stricter standards, greater regulation, more extensive permitting requirements and an increase in the assets we operate, we expect our environmental expenditures to be substantial in the future.

Energy Regulation. PUHCA and the Federal Power Act ("FPA") regulate public utility holding companies and their subsidiaries and place certain constraints on the conduct of their business. The Public Utility Regulatory Policies Act of 1978 ("PURPA") provides to qualifying facilities ("QFs") exemptions from federal and state laws and regulations, including PUHCA and most provisions of the FPA. The Energy Policy Act of 1992 also provides relief from regulation under PUHCA to exempt wholesale generators ("EWGs") and foreign utility companies ("FUCOs"). Maintaining the status of our facilities as QFs, EWGs or FUCOs is conditioned on their continuing to meet statutory criteria, and could be jeopardized, for example, by the making of retail sales by an EWG in violation of the requirements of the Energy Policy Act. Until the completion of the merger between Northern States Power and New Century Energies, we are not and will not be subject to regulation as a registered holding company under PUHCA as long as the domestic power plants we own are QFs under PURPA or are EWGs, and as long as our foreign utility operations are exempted as EWGs or FUCOs or are otherwise exempted under PUHCA; thereafter, we will be subject to the regulations described in "Business -- Energy Regulation -- United States." These regulations include restrictions imposed upon aggregate investment by registered holding companies in EWGs and FUCOs that are financed by contributions or guarantees by the parent holding company. These investment restrictions, issued pursuant to SEC regulations, limit registered holding company investment in EWGs and FUCOs without prior SEC approval to 50% of the registered holding company's consolidated retained earnings. The existence of such investment cap and the potential need to request SEC waivers of or increases in the cap could delay or prevent any infusions of capital from Xcel Energy that it may otherwise desire to make.

We are continually in the process of obtaining or renewing federal, state and local approvals required to operate our facilities. Additional regulatory approvals may be required in the future due to a change in laws and regulations, a change in our customers or other reasons. We may not always be able to obtain all required regulatory approvals, and we may not be able to obtain any necessary modifications to existing regulatory approvals or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain and comply with any required regulatory approvals, the operation of our facilities or the sale of electricity to third parties could be prevented or subject to additional costs.

Environmental Regulation. In acquiring many of our facilities, we assumed on-site liabilities associated with the environmental condition of those facilities, regardless of when such liabilities arose and whether known or unknown, and in some cases agreed to indemnify the former owners of those facilities for on-site environmental liabilities. We may not at all times be in compliance with all applicable environmental laws and regulations. Steps to bring our facilities into compliance could be prohibitively expensive, and may cause us to be unable to pay our debts when due. Moreover, environmental laws and regulations can change.

For example, on October 14, 1999, Governor Pataki of New York announced that he was ordering the New York Department of Environmental Conservation to require further reductions of sulphur dioxide and nitrogen oxides emissions from New York power plants, beyond that which is required under current federal and state law. These reductions would be phased in between January 1, 2003 and January 1, 2007. Compliance with these emission reductions requirements, if they become effective, could have a material adverse impact on the operation of some of our facilities located in the State of New York.

On May 17, 2000, Governor Rowland of Connecticut issued an Executive Order to the Connecticut Department of Environmental Protection ("CDEP") that requires the CDEP to develop regulations, applicable to power plants and other major sources of air pollution, to further reduce emissions of nitrogen oxides and sulphur dioxides by May 2003. The Executive Order requires reductions of sulphur dioxides by an amount that is 30 to 50% greater than current commitments and reductions of nitrogen oxides that are 20 to 30% greater than current commitments. The Executive Order provides that the CDEP should use market based incentives and a system of creditable emissions allowances or credits to foster cost effective reductions. In addition, the Connecticut legislature has in the past considered, but rejected, legislation that would require older electrical generation stations to comply with more stringent pollution standards than are currently in effect in Connecticut for nitrogen oxides and sulphur dioxide emissions. In 1999 and 2000, legislation was proposed in the Connecticut legislature that could require our Connecticut facilities to rely on more expensive fuels or install additional air pollution control equipment. If such legislation were to become law without reflecting the benefit of critical elements of current federal emission reduction initiatives, such as market based emission trading between sources located across broad geographic regions, our Connecticut facilities may be placed at a significant competitive disadvantage.

We are subject to environmental investigations and lawsuits both on the state and federal level. For instance, the New York Department of Environmental Conservation recently issued a Notice of Violation to us and the prior owner of our Huntley and Dunkirk facilities relating to physical changes made at those facilities prior to our assumption of ownership. The Notice of Violation alleges that these changes represent major modifications undertaken without obtaining the required permits. Although we have a right to indemnification by the previous owner for fines, penalties, assessments and related losses resulting from the previous owner's failure to comply with environmental laws and regulations, if these facilities did not comply with the applicable permit requirements, we could be required, among other things, to install specified pollution control technology to further reduce pollutant emissions from the Dunkirk and Huntley facilities, and we could become subject to fines and penalties associated with the current and prior operation of the facilities. See "Business -- Legal Proceedings."

In addition, on November 3, 1999, the United States Department of Justice filed suit against seven electric utilities for alleged violations of Clean Air Act requirements related to modifications of existing sources at seventeen utility generation stations located in the southern and midwestern regions of the United States. The EPA also issued administrative notices of violation alleging similar violations at eight other power plants owned by some of the electric utilities named as defendants in the lawsuit, and also issued an administrative order to the Tennessee Valley Authority for similar violations at seven of its power plants. To date, no lawsuits or administrative actions have been brought against us or any of our subsidiaries or affiliates or the former owners of our facilities alleging similar violations, although a subsidiary of Conectiv has received information requests from the EPA regarding the Deepwater and BL England facilities that we have agreed to purchase. Lawsuits or administrative actions alleging similar violations at our facilities could be filed in the future and if successful, could have a material adverse effect on our business.

OUR COMPETITION IS INCREASING.

The independent power industry is characterized by numerous strong and capable competitors, some of which may have more extensive operating experience, more extensive experience in the acquisition and development of power generation facilities, larger staffs or greater financial resources than we do. Many of our competitors also are seeking attractive power generation opportunities, both in the United States and abroad. This competition may adversely affect our ability to make investments or acquisitions. In recent

years, the independent power industry has been characterized by increased competition for asset purchases and development opportunities.

In addition, regulatory changes have also been proposed to increase access to transmission grids by utility and non-utility purchasers and sellers of electricity. Industry deregulation may encourage the disaggregation of vertically integrated utilities into separate generation, transmission and distribution businesses. As a result, significant additional competitors could become active in the generation segment of our industry.

WE FACE ONGOING CHANGES IN THE UNITED STATES UTILITY INDUSTRY THAT COULD AFFECT OUR COMPETITIVENESS.

The United States electric utility industry is currently experiencing increasing competitive pressures, primarily in wholesale markets, as a result of consumer demands, technological advances, greater availability of natural gas-fired generation that is more efficient than our generation facilities and other factors. The Federal Energy Regulatory Commission ("FERC") has implemented and continues to propose regulatory changes to increase access to the nationwide transmission grid by utility and non-utility purchasers and sellers of electricity. In addition, a number of states are considering or implementing methods to introduce and promote retail competition. Recently, some utilities have brought litigation aimed at forcing the renegotiation or termination of power purchase agreements requiring payments to owners of QF projects based upon past estimates of avoided cost that are now substantially in excess of market prices. In the future, utilities, with the approval of state public utility commissions, could seek to abrogate their existing power purchase agreements.

Proposals have been introduced in Congress to repeal PURPA and PUHCA, and FERC has publicly indicated support for the PUHCA repeal effort. If the repeal 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 competitive advantages that independent power producers currently enjoy over certain regulated utility companies would be eliminated or sharply curtailed, and the ability of regulated utility companies to compete more directly with independent power companies would 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 independent 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.

In addition, the independent system operators who 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, the independent system operator for the New York Power Pool has recently imposed price limitations on certain ancillary services sold in this market, and, together with several New York utilities, has sought authority from FERC to adjust the market-clearing prices for certain of these services on a retroactive basis. We have joined several other independent power producers in New York in filing a claim with FERC challenging these actions and requests. If our positions do not prevail, our revenues from ancillary services sold in the New York Power Pool could be substantially reduced. Although we would attempt to adjust our business operations to mitigate the future impact of such a ruling, the potential negative impact on our revenues for the first quarter of 2000 would include the potential refund of approximately $8.0 million of revenues collected in February 2000 and the inability to collect approximately $8.2 million included in revenues, but not yet collected, for March 2000.

These types of price limitations and other mechanisms in New York and elsewhere may adversely impact the profitability of our generation facilities that sell energy into the wholesale power markets. 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, we can offer no assurance that we will be able to operate profitably in all wholesale power markets.

RISKS RELATING TO THE MARKET FOR OUR COMMON STOCK

OUR COMMON STOCK WILL HAVE LIMITED VOTING POWER.

Our common stock entitles its holders to one vote for each share, and our class A common stock entitles its holders to ten votes for each share. Upon completion of this offering, class A common stock will constitute approximately 84% of our total outstanding common equity and approximately 98% of total voting power and thus Northern States Power will be able to exercise a controlling influence over our business.

WE CAN OFFER NO ASSURANCE THAT AN ACTIVE PUBLIC MARKET FOR OUR COMMON STOCK WILL DEVELOP.

Prior to the offering, Northern States Power held all of our outstanding common stock and therefore there is no public trading market for our common stock. The common stock has been approved for listing on the NYSE. We can offer no assurance that an active public market will develop or that, if a public market develops, the market price for our common stock will equal or exceed the public offering price set forth on the cover page of this prospectus. See "Underwriting."

A SUBSTANTIAL NUMBER OF OUR SHARES WILL BE AVAILABLE FOR FUTURE SALE BY OUR STOCKHOLDERS, WHICH COULD DEPRESS THE MARKET PRICE OF OUR COMMON STOCK.

Northern States Power will own 147,604,500 shares of class A common stock.

The class A common stock will be convertible into common stock on a share-for-share basis and will be converted if sold by Northern States Power to a third party. We have agreed, if so requested by Northern States Power, to file registration statements and take other steps to enable Northern States Power to sell any shares of common stock held by it. Northern States Power has agreed with the underwriters, subject to certain exceptions, not to sell any shares of common stock for a period of 180 days following the date of this prospectus. Any sales of substantial amounts of common stock could adversely affect the prevailing market prices for the common stock. See "Relationships and Related Transactions", "Shares Eligible for Future Sale" and "Underwriting".

USE OF PROCEEDS

The net proceeds from this offering will be approximately $395.6 million. Approximately $300 million of the net proceeds will be used to repay a loan from Citicorp USA, Inc., which matures on August 31, 2000 and bears interest at a floating rate, which at March 31, 2000 was 6.43%. The proceeds from the Citicorp USA loan were used to fund a portion of the purchase price of the Cajun facilities acquired by us in March 2000.

The remaining net proceeds will be used for general corporate purposes, which may include funding of capital expenditures and potential acquisitions, such as the pending acquisition of generation assets from Conectiv, the development and construction of new facilities and additions to working capital. Funds not immediately required for such purposes may be used to temporarily reduce any outstanding balances under our revolving credit facility. The majority of the outstanding balance on our revolving credit facility was borrowed to fund the acquisition of assets from Connecticut Light & Power and bears interest at a floating rate, which was 7.20% at March 31, 2000.

No proceeds of this offering will be distributed to Northern States Power.

DIVIDEND POLICY

We currently intend to retain future earnings, if any, to fund the development and growth of our business. Therefore, we do not currently anticipate paying any cash dividends.

CAPITALIZATION

Capitalization is the amount invested in a company and is a common measurement of a company's size. The table below shows our cash position and capitalization as of March 31, 2000:

- on an actual basis; and

- on an adjusted basis to give effect to the sale of the 28,170,000 shares of our common stock offered by this prospectus at an initial public offering price of $15.00 per share and the application of the net proceeds from the sale, including the repayment of our $300 million loan from Citicorp USA, after deducting underwriting discounts and commissions and estimated offering expenses.

The table below does not reflect options to purchase approximately 4,400,000 shares of our common stock under stock options granted to employees and non-employee directors under the NRG 2000 Long-Term Incentive Compensation Plan. You should read this table in conjunction with the consolidated financial statements and related notes that are included in this prospectus.

MARCH 31, 2000

	ACTUAL	AS ADJUSTED
	(IN THOUSANDS)	
Cash and cash equivalents	$ 137,923	$ 233,480
Current portion of long-term debt	24,789	24,789
Short-term debt:		
Non-recourse (1)	--	--
Recourse(2)	604,000	304,000
Long-term debt		
Non-recourse (1)	2,300,888	2,300,888
Recourse (2)	1,169,608	1,169,608
Stockholders' equity:		
Preferred stock	--	--
Common stock	--	282
Class A common stock	1,476	1,476
Additional paid-in capital	780,438	1,175,713
Retained earnings	195,956	195,956
Accumulated other comprehensive income (loss)(3)	(105,750)	(105,750)
Total stockholders' equity	872,120	1,267,677
Total capitalization	$4,971,405	$5,066,962

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(1) Non-recourse debt is indebtedness incurred by a subsidiary for which there is no recourse to NRG for repayment.

(2) Recourse debt is a direct corporate-level obligation of NRG.

(3) Represents cumulative currency translation adjustments related to various international projects. See Note 2 to our Financial Statements.

SELECTED CONSOLIDATED FINANCIAL AND OTHER DATA

The selected consolidated financial data set forth below as of December 31, 1995, 1996, 1997, 1998 and 1999 and for the years then ended, have been derived from our audited consolidated financial statements. The financial data set forth below as of March 31, 1999 and March 31, 2000, and for the three-month periods then ended, have been derived from our unaudited financial statements, which were prepared on a basis consistent with our audited consolidated financial statements. We have supplied selected capacity and other data set forth below under the caption "Other Data." All amounts are set forth in thousands, except per share amounts.

CONSOLIDATED STATEMENTS OF INCOME DATA:

	YEAR ENDED DECEMBER 31,						THREE MONTHS ENDED MARCH 31,		
	1995	1996	1997	1998	1999	PRO FORMA 1999(1)	1999	2000	PRO FORMA 2000(1)
OPERATING REVENUES									
Revenues from wholly-owned operations	$64,180	$71,649	$92,052	$100,424	$432,518	$801,080	$37,847	$332,671	$412,653
Equity in earnings of unconsolidated affiliates	28,639	32,815	26,200	81,706	67,500	67,500	8,667	(9,644)	(9,644)
Total operating revenues	92,819	104,464	118,252	182,130	500,018	868,580	46,514	323,027	403,009
OPERATING COSTS AND EXPENSES									
Cost of wholly-owned operations	32,535	36,562	46,717	52,413	269,900	513,944	27,940	214,923	273,551
Depreciation and amortization	8,283	8,378	10,310	16,320	37,026	64,595	4,734	19,987	27,044
General, administrative, and development	34,647	39,248	43,116	56,385	83,572	100,376	15,985	25,180	27,603
Total operating costs and expenses	75,465	84,188	100,143	125,118	390,498	678,915	48,659	260,090	328,198
OPERATING INCOME (LOSS)	17,354	20,276	18,109	57,012	109,520	189,665	(2,145)	62,937	74,811
OTHER INCOME (EXPENSE)									
Minority interest	--	--	(131)	(2,251)	(2,456)	(2,456)	(464)	(1,798)	(1,798)
Other income, net(2)	29,746	9,477	11,502	11,630	17,426	15,556	734	1,531	2,052
Interest expense	(7,089)	(15,430)	(30,989)	(50,313)	(93,376)	(166,624)	(11,059)	(52,317)	(70,629)

Total other income (expense)	22,657	(5,953)	(19,618)	(40,934)	(78,406)	(153,524)	(10,789)	(52,584)	(70,375)
INCOME (LOSS) BEFORE INCOME TAXES	40,011	14,323	(1,509)	16,078	31,114	36,141	(12,934)	10,353	4,436
INCOME TAX (BENEFIT) EXPENSE(3)	8,810	(5,655)	(23,491)	(25,654)	(26,081)	(24,001)	(11,994)	1,607	(841)
NET INCOME (LOSS)	$31,201	$19,978	$21,982	$ 41,732	$ 57,195	$ 60,142	$ (940)	8,746	5,277
Earnings (loss) per share --basic and diluted	$ .21	$ .14	$ .15	$ .28	$ .39	$ .41	$ (.01)	$ .06	$ .04
Weighted average shares outstanding -- basic and diluted	147,605	147,605	147,605	147,605	147,605	147,605	147,605	147,605	147,605

CONSOLIDATED BALANCE SHEET DATA:

	AS OF DECEMBER 31,					AS OF MARCH 31,	
	1995	1996	1997	1998	1999	1999	2000
Net property, plant and equipment	$111,919	$129,649	$ 185,891	$ 204,729	$1,975,403	$ 207,473	$3,669,654
Net equity investments in projects	221,129	365,749	694,655	800,924	932,591	814,807	893,303
Total assets	454,589	680,809	1,168,102	1,293,426	3,431,684	1,298,679	5,293,808
Long-term debt, including current maturities	90,034	212,141	620,855	626,476	1,971,860	498,019	3,495,285
Stockholder's equity	319,764	421,914	450,698	579,332	893,654	680,017	872,120

OTHER DATA:

	AS OF AND FOR THE YEAR ENDED DECEMBER 31,					AS OF AND FOR THE THREE MONTHS ENDED MARCH 31,
	1995	1996	1997	1998	1999	2000
Consolidated EBITDA(4)	55,383	38,131	39,790	82,711	161,516	82,657
Total debt to total capitalization ratio	22.0%	33.5%	57.9%	52.0%	72.4%	82.5%
Ratio of recourse debt to recourse debt and equity	5.4%	30.9%	52.6%	46.6%	58.4%	67.0%
Consolidated interest expense coverage ratio(5)	7.81x	2.47x	1.28x	1.64x	1.72x	1.58x
Power generation capacity (MW), net	999	1,326	2,637	3,300	10,990	13,664
Thermal energy generation capacity:						
mmBtus per hour, net	2,318	2,654	2,693	2,905	3,400	3,400
MW equivalent, net(6)	812	917	950	1,012	1,204	1,204

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(1) The pro forma financial information gives effect to our March 31, 2000 acquisition of the Cajun facilities as if that acquisition had occurred on January 1, 1999. We do not believe that the pro forma data is indicative of our future revenues and earnings, because the previous owner of the Cajun facilities sold energy and capacity and purchased coal upon terms substantially different from those under which we will operate these facilities. Thus, we believe the pro forma financial information is of limited use in making an investment decision.

(2) These amounts include equity in gain from project termination settlements in 1995 of $29.9 million related to the settlement and termination of the San Joaquin Valley power purchase agreements with Pacific Gas & Electric, and include pretax charges of $5.0 million in 1995, $1.5 million in 1996, $9.0 million in 1997, $26.7 million in 1998 and $0 in 1999, to write down the carrying value of certain energy projects. These amounts also include the gain on sale of interest in projects of $8.7 million in 1997, $30.0 million in 1998 and $15.5 million in 1999.

(3) We are included in the consolidated federal income tax and state franchise tax returns of Northern States Power. We calculate our tax position on a separate company basis under a tax sharing agreement with Northern States Power and receive payment from Northern States Power for tax benefits and pay Northern States Power for tax liabilities.

(4) EBITDA is the sum of income (loss) before income taxes, interest expense (net of capitalized interest) and depreciation and amortization expense. EBITDA is a measure of financial performance not defined under generally accepted accounting principles, which you should not consider in isolation or as a substitute for net income, cash flows from operations or other income or cash flow data prepared in accordance with generally accepted accounting principles or as a measure of a company's profitability or liquidity. In addition, EBITDA may not be comparable to similarly titled measures presented by other companies and could be misleading because all companies and analysts do not calculate it in the same fashion.

(5) This coverage ratio equals EBITDA divided by interest expense.

(6) Our conversion of thermal generation capacity to MW from British thermal units per hour is based upon the thermal constant of 3,412.14 British thermal units per hour per kilowatt hour. Our conversion of chilled water capacity to MW is based upon 12,000 British thermal units per hour per ton of chilled water capacity, as well as the thermal constant of 3,412.14 British thermal units per hour per kilowatt hour.

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

You should read the following in conjunction with our consolidated financial statements and notes thereto, "Risk Factors," and "Selected Consolidated Financial and Other Data," included elsewhere in this prospectus. A complete listing of our projects that are discussed in this section is set forth on the inside back cover of this prospectus.

OVERVIEW

We are a leading global energy company primarily engaged in the acquisition, development, ownership and operation of power generation facilities and the sale of energy, capacity and related products. We have grown significantly during the last three years. During this period, we have grown from a company deriving most of our revenues from power generation facilities in which we owned less than a 50% interest and from heating, cooling and thermal activities, to one of the largest independent power generation companies in the United States (measured by our net ownership interests in power generation projects), deriving over 78% of our revenues from our wholly-owned power generation facilities in 1999.

Since January 1, 1997, we have acquired 12,338 MW of net ownership interests in power generation facilities. During 1997, we acquired 1,311 MW of net ownership interests in power generation facilities, primarily as a result of our acquisition of interests in Crockett Cogeneration and other projects. In 1998, we acquired a 50% interest in 1,218 MW of generating capacity in Southern California. Since January 1, 1999, we have acquired an additional 6,980 MW of 100% owned generating capacity in the Northeast United States, 680 MW of 100% owned generating capacity in the United Kingdom and 1,708 MW of 100% owned generating capacity in Louisiana. We intend to continue growing through targeted acquisitions, repowering and the expansion of existing facilities and the development of new greenfield projects.

Source of Revenues and Equity in Earnings of Unconsolidated Affiliates. Our operating revenues and expenses are primarily related to the operations of our controlled subsidiaries, which are consolidated for accounting purposes. Significant consolidated subsidiaries include NRG Northeast Generating LLC, NRG South Central Generating LLC, NEO Corporation, NRG Thermal Corporation, and Crockett Cogeneration. Investments in project companies over which we exercise significant influence, but do not control, are accounted for using the equity method of accounting. The operating results of these entities are reflected in total operating revenues in the form of equity in earnings of affiliates. Significant investments accounted for using the equity method include MIBRAG, Gladstone, Schkopau, Loy Yang, COBEE, West Coast Power LLC, Energy Developments Limited and ECK Generating. In 1999, we consolidated our Pittsburgh and San

Francisco thermal operations and Crockett Cogeneration, which we previously accounted for using the equity method.

Our operating revenues are derived primarily from the sale of electrical energy, capacity and other energy products from our power generation facilities. Revenues from these facilities are received pursuant to:

- long-term contracts of more than one year including:
  - power purchase agreements with utilities and other third parties (generally 2-25 years);
  - standard offer agreements to provide load serving entities with a percentage of their requirements (generally 4-9 years); and
  - "transition" power purchase agreements with the former owners of acquired facilities (generally 3-5 years).
- short-term contracts or other commitments of one year or less and spot sales including:
  - spot market and other sales into various wholesale power markets; and
  - bilateral contracts with third parties.

The following charts illustrate the sources of our domestic power generation revenue (excluding thermal and resource recovery revenues and the revenues of NEO Corporation) and equity in earnings of international affiliates engaged in power generation for the year ended December 31, 1999:

DOMESTIC

LONG TERM	SHORT TERM
73	27

INTERNATIONAL(1)

LONG TERM	SHORT TERM
96	4

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(1) Consists solely of equity in earnings of international affiliates.

Operating Costs and Expenses. The principal costs and expenses of our operations are fuel used to generate energy, labor to operate and maintain our facilities, depreciation and amortization, general and administrative costs and development expenses.

Seasonality. Demand for energy as well as energy and capacity prices tend to be higher in peak market periods, which are dictated by weather patterns. As a result of a portfolio consisting of assets predominantly located in the United States, we expect our revenues and profitability to be highest during the third quarter of the calendar year.

RESULTS OF OPERATIONS

THREE MONTHS ENDED MARCH 31, 2000 COMPARED TO THREE MONTHS ENDED MARCH 31, 1999

Revenues. For the quarter ended March 31, 2000, we had total revenues of $323.0 million, which includes operating revenues and equity in earnings of unconsolidated affiliates, compared to $46.5 million for the quarter ended March 31, 1999, an increase of $276.5 million or 594.5%. Our operating revenues from wholly-owned operations were $332.7 million, an increase of $294.8 million or 780%, over the same period in 1999. Revenues from our Northeast assets that were acquired during 1999 accounted for approximately $228.0 million of this increase. Approximately $35.8 million of the increase was due to a tolling agreement related to the Killingholme facility, which was in effect from January 1, 2000 to the date of our acquisition of this facility, March 29, 2000. Also, the acquisition of additional ownership interests in, and the resulting consolidation of, our Pittsburgh and San Francisco thermal operations together with the consolidation of Crockett Cogeneration accounted for approximately $25.5 million of the increase in revenues. For the quarter ended March 31, 2000, revenues from wholly owned operations consisted of revenue from electrical generation (92.4%), heating, cooling and thermal activities (6.5%) and technical services (1.1%).

Equity in losses of unconsolidated project affiliates was $9.6 million for the quarter ended March 31, 2000, compared to earnings of $8.7 million for the quarter ended March 31, 1999, a decrease of 211%. Reduced earnings from our investment in West Coast Power LLC accounted for $11.1 million of the decrease. The West Coast Power LLC results were down due to interest on project level debt that was issued in June 1999, a favorable business interruption insurance settlement that was recorded in the first quarter of 1999, and costs associated with the Encina facility and the San Diego combustion turbines, which are summer peaking facilities that were acquired in May 1999. In addition, equity earnings from NEO decreased by $2.4 million primarily due to operating losses from a project that was acquired in October 1999. This project produces a net profit for us after consideration of Section 29 credits, which are included in income taxes. Equity earnings from the Loy Yang project decreased by $2.4 million due to a

change in accounting for tax benefits associated with the project. Equity earnings were also reduced by the consolidation of our Pittsburgh and San Francisco thermal operations and Crockett Cogeneration subsidiaries during 1999.

Operating Costs and Expenses. Cost of wholly-owned operations was $214.9 million for the quarter, an increase of $187.0 million, or 669.2%, over the same period in 1999. Approximately $146 million of the increase was due to the acquisition of our Northeast assets during 1999. The remaining increase was primarily due to the consolidation of Crockett Cogeneration and the Pittsburgh and San Francisco thermal operations. Cost of operations, as a percentage of revenues from wholly-owned operations for the period, was 64.6% which is 12.6% less then the prior year period.

Our depreciation and amortization costs were $20.0 million for the quarter ended March 31, 2000, compared to $4.7 million for the quarter ended March 31, 1999. The increase resulted primarily from the addition of our Northeast assets during 1999 and the acquisition of additional ownership interests in, and the resulting consolidation of, our Pittsburgh and San Francisco thermal operations, together with the consolidation of Crockett Cogeneration, which contributed to the increase in depreciation and amortization.

Our general, administrative and development costs were $25.2 million for the quarter ended March 31, 2000, compared to $16.0 million for the quarter ended March 31, 1999. The $9.2 million increase is due primarily to increased business development, associated legal, technical, and accounting expenses, employees and equipment resulting from expanded operations and preparation for several acquisitions that took place in 1999 and during the first quarter of 2000. As a percent of total revenues, administrative and general expenses declined to 7.8% from 34.4% during the same period one-year earlier.

Other Income (Expense). Other expense was $52.6 million for the quarter, compared with $10.8 million for the same period in 1999. The increase in Other Expense was primarily due to an increase in interest expense, which was $52.3 million for the quarter, compared to $11.0 million for the quarter ended March 31, 1999. We added $750 million of project level debt related to our Northeast asset acquisitions resulting in $18.2 million of incremental interest expense. In addition, we issued $300 million of senior notes in June 1999 and $240 million of senior notes in November 1999. Also, a higher average outstanding balance of our revolving line of credit and the consolidation of Crockett Cogeneration and our Pittsburgh and San Francisco thermal operations contributed to higher interest expense.

Income Tax. Because we are included in the consolidated federal income tax return of Northern States Power, we pay to and we are paid by Northern States Power on a dollar-for-dollar basis for the increase or reduction, respectively, of Northern States Power's taxes attributable to the respective tax liabilities or benefits we create. Income tax expense was $1.6 million for the quarter ended March 31, 2000, compared to an income tax benefit of $12.0 million for the quarter ended March 31, 1999. The increase in income tax expense was primarily due to higher United States taxable income versus foreign taxable income. In addition, we no longer recognized the tax benefits related to the losses generated by the Loy Yang facility. This increase in tax expense was partially offset by additional Section 29 tax credits generated by growth in NEO's portfolio of landfill gas projects.

Net Income. Net income for the quarter ended March 31, 2000, was $8.7 million, an increase of $9.7 million compared to net loss of $0.9 million in the same period in 1999. This increase was due to the factors described above.

The independent system operator for the New York Power Pool has recently sought authority from FERC to adjust the market-clearing prices for certain ancillary services on a retroactive basis beginning January 29, 2000. We and several other independent power producers are challenging this action. If the independent system operator prevails, our revenues from ancillary services sold in the New York Power Pool could be substantially reduced. Although we would attempt to adjust our business operations to mitigate the future impact of such a ruling, the potential negative impact on our revenues for the first quarter of 2000 would include the potential refund of approximately $8.0 million of revenues collected in February 2000 and the inability to collect approximately $8.2 million included in revenues, but not yet collected, for March 2000.

As of the effective date of the offering, we will issue approximately 3.3 million options in replacement of existing unvested equity units. The aggregate difference between the initial public offering price of $15.00 per share and the exercise prices of these options is approximately $23.9 million. We have already accrued approximately $14.0 million on our financial statements in connection with the unvested equity units and related options. The amount by which the aggregate difference described above exceeds the accrued amount will be amortized over the next 6 1/2 years based on the vesting schedule of the underlying options.

FISCAL YEAR ENDED DECEMBER 31, 1999 COMPARED TO FISCAL YEAR ENDED DECEMBER 31, 1998

Revenues. For the year ended December 31, 1999, we had total revenues of $500.0 million, which includes operating revenues and equity in earnings of unconsolidated affiliates, compared to $182.1 million for the year ended December 31, 1998, an increase of $317.9 million or 174.5%. Our operating revenues from wholly-owned operations were $432.5 million, an increase of $332.1 million, or 330.7%, over the same period in 1998. Revenues from our Northeast assets that were acquired during 1999 accounted for approximately $303.6 million of this increase. In 1999, the acquisition of additional ownership interests in, and resulting consolidation of, our Pittsburgh and San Francisco thermal operations, together with the consolidation of Crockett Cogeneration, accounted for approximately $29.1 million of the increase in revenues. In 1999, operating revenues from wholly-owned operations consisted of revenue from electrical generation (78.3%), heating, cooling and thermal activities (17.6%) and technical services (4.1%), and in 1998, they consisted of operating revenue from electrical generation (46.2%), heating, cooling and thermal activities (46.0%) and technical services (7.8%).

For 1999, our equity in earnings of unconsolidated affiliates was $67.5 million, compared to $81.7 million for 1998, a decrease of $14.2 million or 17.4%. This change was primarily the result of a cooler summer in the western region of the United States in 1999 and financing costs related to our El Segundo and Long Beach generation facilities, which accounted for a $12.8 million reduction in equity in earnings from these affiliates. Lower earnings at Mt. Poso, together with the consolidation of our Pittsburgh and San Francisco thermal operations and Crockett Cogeneration also contributed to the decrease in equity in earnings during 1999. These decreases were partially offset by increased earnings from MIBRAG and a favorable legal settlement at one of our affiliates.

Operating Costs and Expenses. For 1999, our cost of wholly-owned operations was $269.9 million, compared to $52.4 million in 1998, an increase of $217.5 million or 415%. Costs associated with the ownership and operation of our Northeast assets that were acquired during 1999 accounted for approximately $194.9 million of the $269.9 million. The remaining increase resulted from the consolidation of our Pittsburgh and San Francisco thermal operations and Crockett Cogeneration. Increases also resulted from the addition of new projects during 1999 by NEO.

Our depreciation and amortization costs were $37.0 million for 1999, compared to $16.3 million for 1998, an increase of $20.7 million or 127%. This increase resulted primarily from the addition of our Northeast assets and the addition of new projects by NEO. The acquisition of additional ownership interests in, and resulting consolidation of, our Pittsburgh and San Francisco thermal operations, together with the consolidation of Crockett Cogeneration, also contributed to the increase in depreciation and amortization.

Our general and administrative costs were $59.9 million for 1999, compared to $42.0 million for 1998, an increase of $17.9 million or 43%. Approximately $7.8 million of the increase was a direct result of the ownership and operation of our Northeast assets during 1999. The remaining increase was due primarily to the consolidation of certain affiliates described above, which were previously accounted for using the equity method, and an overall increase in legal, technical and accounting support resulting from expanded operations.

Our development expenses were $23.7 million for 1999, compared to $14.4 million for 1998, an increase of $9.3 million or 65%. Our development expenses include development office costs, internal personnel costs, and fees paid to outside service providers in connection with the pursuit of new investment

opportunities. The 1999 increase was due primarily to the pursuit of a greater number of potential opportunities during the year.

Other Income (Expense). Minority interest in projects was $2.5 million for 1999 compared to $2.3 million for 1998. Minority interest relates to projects that were acquired in November 1997 and thermal operations in which we have a minority interest.

Other income, net was $17.4 million in 1999 compared to $11.6 million in 1998, an increase of $5.8 million or 50%. This increase was primarily the result of the 1999 pretax gain of $11.0 million on the sell-down of our ownership interest in Cogeneration Corporation of America from approximately 45% to 20%. This increase was offset in part by a $2.0 million reclassification of management fees from income to equity in earnings of unconsolidated subsidiaries, compared to a 1998 $29.9 million gain from sale of interests in projects, offset in part by a $26.7 million write down of the carrying value of other projects. The 1998 charges included a $22.0 million write off of our entire investment, which included development expenses as well as fees incurred in connection with the termination of an interest rate hedge, in a project we were pursuing in West Java, Indonesia. This write off was due to uncertainties surrounding infrastructure projects in Indonesia.

Interest expense was $93.4 million for 1999 compared with $50.3 million for 1998, an increase of $43.1 million or 86%. The increase in interest expense primarily resulted from the acquisition of our Northeast assets, which was primarily funded at the end of the second quarter, and the issuance of $300 million of senior notes in June 1999 and $240 million of senior notes in November 1999. In addition, a higher average outstanding balance on our revolving line of credit and the consolidation of Crockett Cogeneration and our Pittsburgh and San Francisco thermal operations contributed to higher interest expense.

Income Tax. We generated substantial income tax benefits as a result of our operations. Because we are included in the consolidated federal income tax return of Northern States Power, we pay to and we are paid by Northern States Power on a dollar-for-dollar basis for the increase or reduction, respectively, of Northern States Power's taxes attributable to the respective tax liabilities or benefits we create. We have recorded an income tax benefit due to the recognition of Section 29 tax credits associated with NEO, foreign tax benefits related to the Loy Yang project and tax losses resulting from accelerated depreciation of certain fixed assets. The Section 29 credits comprised $20.4 million of our 1999 tax benefit compared with $15.9 million in 1998. The increase in Section 29 credits is due to the growth of NEO's portfolio of landfill gas projects.

Net Income. For 1999, we had net income of $57.2 million compared to $41.7 million in 1998, an increase of $15.5 million or 37.2%. This increase was due to the factors described above.

FISCAL YEAR ENDED DECEMBER 31, 1998 COMPARED TO FISCAL YEAR ENDED DECEMBER 31, 1997

Revenues. For the year ended December 31, 1998, we had total revenues of $182.1 million, compared to $118.3 million for the year ended December 31, 1997, an increase of $63.8 million or 54%. Operating revenues from wholly-owned operations for 1998 were $100.4 million, compared to $92.0 million in 1997, an increase of $8.4 million, or 9.1%. The acquisition of new facilities, principally the Camas Power Boiler, accounted for this increase. Unusually mild weather in 1998 in the upper Midwest led to lower revenues in our heating and cooling operations, which partially offset the 1998 revenue increase. In 1998, operating revenues from wholly-owned operations consisted of revenue from electrical generation (46.2%), heating, cooling and thermal activities (46.6%), and technical services (7.8%), while in 1997, they consisted of operating revenues from heating, cooling and thermal activities (54%), electrical generation (32%), and technical services (14%).

For 1998, our equity in earnings of unconsolidated affiliates was $81.7 million, compared to $26.2 million for 1997, an increase of $55.5 million or 212%. This increase primarily resulted from the acquisition of interests in new projects, including the El Segundo, Long Beach, Crockett Cogeneration and

Mt. Poso projects, an increase in our holdings in Energy Developments Limited, and improved performance during a full year of ownership from Loy Yang.

Operating Costs and Expenses. For 1998, our cost of wholly-owned operations was $52.4 million, compared to $46.7 million in 1997, an increase of $5.7 million or 12%. The increase in cost of operations was due to new NEO projects and increased expenses in our heating, cooling and thermal operations.

Our depreciation and amortization costs were $16.3 million for 1998, compared to $10.3 million for 1997, an increase of $6.0 million or 58%. The depreciation and amortization increase primarily resulted from increased amortization of intangible assets related to the acquisition of Crockett Cogeneration and other projects and additional depreciation due to the acquisition of additional projects by NEO.

Our general and administrative costs were $42.0 million for 1998, compared to $32.2 million for 1997, an increase of $9.8 million or 30%. This increase was due primarily to increased legal, technical and accounting expenses resulting from expanded operations.

Our development expenses were $14.4 million for 1998, compared to $10.9 million for 1997, an increase of $3.5 million or 32%. This increase was due primarily to increased business development activities.

Other Income (Expense). Minority interest in projects was $2.3 million for 1998 compared to $0.1 million for 1997. Minority interest relates to projects that were acquired in November 1997. We recorded a total gain of $30.0 million in 1998 related to project sales. In October 1998, we sold our 110 MW Mid-Continent Power Company facility in Oklahoma to Cogeneration Corporation of America, our affiliate, for a $2.1 million gain. Also in October 1998, we sold 13.35% of our interest in ECK Generating for a gain of $1.6 million. We continue to own a 44.5% interest in the ECK Generating project. In December 1998, we sold half of our 50% interest in our Enfield project to an affiliate of El Paso International for a $26.2 million gain.

For 1998, we recorded $26.7 million in total project write-downs compared to write-downs of $9.0 million in 1997. The 1998 write down included a $22.0 million write off of our entire investment, which included development expenses as well as fees incurred in connection with the termination of an interest rate hedge, in a project we were pursuing in West Java, Indonesia, a $1.9 million charge related to our investment in the Sunnyside project in Utah and $2.8 million of accumulated project development expenditures related to the Alto Cachopoal project in Chile. The 1997 charges consisted of a write-down of our investment in the Sunnyside project. At the end of 1998, no amounts remained on the balance sheet for these investments.

Other income of $8.4 million in 1998 compared to $11.8 million in 1997 primarily reflected a reduction in interest income from loans to affiliates during 1998.

Interest expense was $50.3 million for 1998 compared with $31.0 million for 1997, an increase of $19.3 million or 62%. This increase was due primarily to the issuance of $250 million of senior notes in June 1997, interest on larger balances outstanding under our revolving line of credit incurred in connection with the purchase of Crockett Cogeneration and other projects and new debt obtained for certain NEO projects.

Income Tax. The Section 29 credits comprised $15.9 million of our 1998 tax benefit compared with $9.8 million in 1997. The increase in Section 29 credits was due to the growth of NEO's portfolio of landfill gas projects.

Net Income. For 1998, we had net income of $41.7 million compared to $22.0 million in 1997, an increase of $19.7 million or 90%. This increase was due to the factors described above.

LIQUIDITY AND CAPITAL RESOURCES

To date, we and our subsidiaries have obtained cash from operations, issuance of debt securities, borrowings under credit facilities, capital contributions from Northern States Power, the sale of tax benefits

to Northern States Power and proceeds from non-recourse project financing. 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.

From January 1, 1997, through March 31, 2000, our financing activities provided cash totaling approximately $3,991 million, including $430.9 million in capital contributions from Northern States Power. Financing activities for 1999 included $1,473 million in gross proceeds from the issuance of long and short term debt and $250.0 million of capital contributions from Northern States

Power. These inflows were partially offset by $18.6 million in payments on long-term debt. In 1999, we used $11.4 million of cash in operating activities. Our use of cash in 1999 primarily related to ongoing working capital requirements for new operations. During the three months ended March 31, 2000, financing activities included $2,446.9 million in gross proceeds from the issuance of long-term and short-term debt. These inflows were partially offset by $715.5 million in repayments of long-term debt. For the three months ended March 31, 2000, we generated $156.8 million of cash in operating activities.

Financings at the NRG Level. Our objective is to maintain and improve our credit ratings, which are presently at "Baa3" from Moody's and "BBB-" from Standard & Poor's. We intend to do so by prudently leveraging our project subsidiary companies and by maintaining a corporate capital structure that is consistent with these credit rating objectives.

Since January 1997, we have issued approximately $1,040 million of long-term corporate-level indebtedness. All of such debt is unsecured and ranks senior to all of our existing and future subordinated indebtedness. This amount includes $250 million of 7.5% senior notes due 2007 and $300 million of 7.5% senior notes due 2009. These senior notes were used primarily to support equity requirements for projects acquired and in development. Interest on all of these notes is paid semi-annually through their maturity dates.

In November 1999, we issued $240 million of 8% remarketable or redeemable securities ("ROARS") due 2013. On November 1, 2003, Credit Suisse Financial Products may remarket the ROARS at a fixed rate of interest through 2013 or, at our option, at a floating rate of interest for up to one year and then at a fixed rate of interest through 2013. Interest is payable semi-annually beginning May 1, 2000 through November 1, 2003, and then at intervals and interest rates specified in the indenture. On November 1, 2003, the ROARS will either be mandatorily tendered to and purchased by Credit Suisse Financial Products or mandatorily redeemed by us at prices specified in the indenture.

In March 2000, we issued L160 million (approximately $250 million at the time of issuance) of 7.97% reset senior notes due 2020, principally to finance our equity investment in the Killingholme facility. On March 15, 2005, these senior notes may be remarketed by Bank of America, N.A. at a fixed rate of interest through the maturity date or, at our option, at a floating rate of interest for up to one year and then at a fixed rate of interest through 2020. Interest is payable semi-annually on these securities beginning September 15, 2000 through March 15, 2005, and then at intervals and interest rates established in the remarketing process. On March 15, 2005, these senior notes will either be mandatorily tendered to and purchased by Bank of America or mandatorily redeemed by us at prices specified in the indenture.

In addition, we have a $500 million revolving credit facility with ABN AMRO Bank, N.V. under a commitment fee arrangement that matures on March 9, 2001. This facility provides short-term financing in the form of bank loans. At March 31, 2000, we had $304 million outstanding under this facility.

In March 2000, we borrowed $300 million under a short-term bridge facility with Citicorp USA, Inc., that expires on August 31, 2000 and bears interest at a floating rate, which was 6.43% at March 31, 2000. Proceeds from this loan, which were used to fund the acquisition of the Cajun facilities, will be repaid with a portion of the proceeds of this offering. In connection with the extension of this bridge facility, Northern States Power provided a support agreement on our behalf to Citicorp USA.

In November 1999, we entered into a $125 million standby letter of credit facility with Australia and New Zealand Banking Group Limited as administrative agent. The facility provides for issuances of letters

of credit for our account with respect to financial and performance guarantees that we or our project affiliates undertake. The facility terminates on November 31, 2002.

Financings at the Project Level. We have generally financed the acquisition and development of our projects under financing arrangements to be repaid solely from each of our project's cash flows, which are typically secured by the plant's physical assets and equity interests in the project company. We have agreed, in some instances, to undertake limited financial support for certain of our project affiliates in the form of certain limited obligations and contingent liabilities. As of March 31, 2000, our affiliates had approximately $2,325 million of indebtedness outstanding which is non-recourse to us. The most significant of these financings include the following:

- $800 million of senior secured bonds issued by NRG South Central Generating LLC in March 2000 consisting of:

  - $500 million of 8.962% bonds due 2016; and

  - $300 million of 9.479% bonds due 2024.

- $750 million of senior secured bonds issued by NRG Northeast Generating LLC in February 2000 consisting of:

  - $320 million of 8.065% bonds due 2004;

  - $130 million of 8.842% bonds due 2015; and

  - $300 million of 9.292% bonds due 2024.

- In March 2000, three of our subsidiaries entered into a L335 million (approximately $533 million at March 31, 2000) secured borrowing facility agreement with Bank of America International Limited, as arranger. Under this facility, the financial institutions party to the facility agreement have made available to our subsidiaries various term loans (L235 million) for the purpose of financing the acquisition of the Killingholme facility and revolving credit and letter of credit facilities (collectively, L100 million) for the purpose of providing working capital for operating the Killingholme facility and for other purposes. The final maturity date of the facility is the earlier of June 30, 2019, or the date on which all borrowings and commitments under the largest tranche of the term loan facility have been repaid or cancelled.

- $255 million of 8.13% secured indebtedness due 2014 of Crockett Cogeneration that we recorded in 1999 when we consolidated this entity for accounting purposes as a result of an increase in our percentage interest in future distributions due to satisfaction of specified aggregate distribution levels by Crockett Cogeneration to its owners.

We have used cash flows provided by our financing activities primarily to facilitate investments in our subsidiaries. From January 1, 1997, through December 31, 1999, we used approximately $2,286 million of cash for our investing activities. In 1999, we incurred $94.9 million in capital expenditures.

Over the next several years, we intend to focus on the expansion or repowering of existing facilities and the development of greenfield projects as well as acquisitions of thermal energy production and transmission facilities in the United States. Internationally, we intend to continue to pursue development and acquisition opportunities in selected countries. We expect to meet our cash and financing needs over the next several years through a combination of cash flows from operations and additional financing arrangements.

We have committed to purchase the Conectiv assets for approximately $800 million in late 2000 and intend to finance this purchase with a combination of project-level and corporate-level debt. Additionally, we have contracted to purchase 16 turbine generators from General Electric at an acquisition cost of approximately $500 million payable over five years, as well as two turbines from Great River Energy for $43 million. In addition, we have ongoing annual capital expenditures of approximately $35 to $70 million for environmental and other investment at our existing projects. We expect to fund the turbine purchases and these levels of ongoing capital expenditures from internally generated cash flow.

Our future growth strategy is dependent upon significant new capital investment. We expect to expend, principally through our project subsidiaries, approximately $1,050 million (including $800 million for the acquisition of assets from Conectiv) to acquire non-regulated projects and properties during the remainder of 2000. We expect to finance our future capital requirements with a combination of project-level debt, internally generated funds, corporate-level debt and additional equity. Our ability to arrange future financing is dependent on a number of factors. To the extent we were unable to raise additional capital on attractive terms either at the corporate level or on a non-recourse project level, it would have a material adverse effect on our ability to grow.

IMPACT OF ENERGY PRICE CHANGES, INTEREST RATES AND FOREIGN CURRENCY FLUCTUATIONS

We use derivative financial instruments to mitigate the impact of changes in electricity and fuel prices on our margins, the impact of changes in foreign currency exchange rates on our international project cash flows and the impact of changes in interest rates on our cost of borrowing.

Electricity and fuel prices tend to fluctuate significantly as they are influenced by many factors, including general economic conditions and changes in supply and demand. In particular, our power marketing subsidiary is exposed to the risk of changes in market prices of fuel oil, natural gas and electricity. To assist us in achieving our objective of maximizing net operating margins while minimizing our exposure to volatility in the electricity, fuel oil and natural gas markets, our power marketing subsidiary, NRG Power Marketing, uses a variety of instruments, including options, swaps and forward contracts. Contracts for the transmission and transportation of these commodities are also authorized, as necessary, in order to meet physical delivery requirements and obligations.

NRG Power Marketing operates within strict risk management guidelines that have been approved by its board of directors. These guidelines:

- generally prohibit speculative trading activities, meaning that we have to be able to produce from our assets, or accept and utilize the commodity being traded;

- do not permit more than 50% of the uncommitted energy or capacity of any facility to be sold forward without the approval of the board of directors of NRG Power Marketing; and

- require approval of all counter parties and their trading limits by our Treasurer.

As of December 31, 1999, a 10% increase in fuel oil, natural gas and electricity forward prices would have resulted in a gain on our outstanding forward contracts of approximately $11.9 million. Conversely, a 10% decrease in fuel oil, natural gas and electricity forward prices would have resulted in a loss on these contracts of approximately $11.9 million. These potential gains and losses on energy forward contracts may be offset by the gains and losses on the underlying commodities being hedged.

For all derivative financial instruments, we and our subsidiaries are exposed to losses in the event of nonperformance by counter parties to such derivative financial instruments. We have established controls to determine and monitor the creditworthiness of counter parties in order to mitigate our exposure to counter party credit risk.

SFAS 52 requires foreign currency gains to be reflected in the income statement if settlement of an obligation is in a currency other than the local currency of the entity. A portion of the Kladno project debt is in non-local currencies, namely United States dollars and German deutsche marks. As of December 31, 1999, if the value of the Czech koruna had decreased by 10% in relation to the United States dollar and the German deutsche mark, we would have recorded a $5.5 million after tax loss on the currency transaction adjustment.

If the value of the Czech koruna were to have increased by 10%, we would have recorded a $5.5 million after tax gain on the currency transaction adjustment. The potential impacts on our income statement of these currency fluctuations are a result of the debt structure of the project and are

not indicative of the long-term earnings potential of the investment. Kladno is the only project we have at this time with this type of debt structure.

We have historically used interest rate hedging contracts to mitigate the risks associated with movements in interest rates and, when deemed appropriate, have entered into swap agreements effectively converting fixed rate obligations into floating rate obligations. As of March 31, 2000, we had four interest rate swap agreements with notional amounts totaling approximately $692 million. If the swaps had been discontinued on March 31, 2000, we would have owed the counter parties approximately $2 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 entered into a swap agreement effectively converting the 7.5% fixed rate on $200 million of our Senior Notes due 2007 to a variable rate based on the London Interbank Offered Rate. The swap expires on June 1, 2009.

- A second swap effectively converts a $16 million issue of non-recourse variable rate debt into a fixed rate debt. The swap expires on September 30, 2002 and is secured by the Camas Power Boiler assets.

- A third swap converts $177 million of non-recourse variable rate debt into fixed rate debt. The swap expires on December 17, 2014 and is secured by the Crockett Cogeneration assets.

- A fourth swap converts L188 million of non-recourse variable rate debt into fixed rate debt. The swap expires on June 30, 2019 and is secured by the Killingholme assets.

NEW ACCOUNTING STANDARDS

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." This statement requires that all derivatives be recognized at fair value in the balance sheet and that changes in fair value be recognized either currently in earnings or deferred as a component of Other Comprehensive Income, depending on the intended use of the derivative, its resulting designation and its effectiveness. We plan to adopt this standard in the first quarter of 2001, as required. We have not determined the potential impact of implementing this statement.

BUSINESS

INTRODUCTION

We are a leading global energy company primarily engaged in the acquisition, development, ownership and operation of power generation facilities and the sale of energy, capacity and related products. We believe we are one of the three largest independent power generation companies in the United States and the sixth largest independent power generation company in the world measured by our net ownership interest in power generation facilities. We own all or a portion of 57 generation projects that have a total generating capacity of 23,660 MW; our net ownership interest in those projects is 13,664 MW. Upon the closing of our pending acquisition from Conectiv of interests in six power generation facilities, which we expect to occur later this year, we will have interests in projects having a total generating capacity of 28,722 MW; our net ownership interest in those projects will be 15,539 MW. In addition, we have an active acquisition and development program through which we are pursuing additional generation projects.

As the following table illustrates, we have grown significantly during the last three years, primarily as a result of our success in acquiring domestic power generation facilities:

	YEAR ENDED DECEMBER 31,		
	1997	1998	1999
Net Ownership Interest (in MW at year end)(1)......	2,637	3,300	10,990
Operating Income (in thousands)....................	$18,109	$57,012	$109,520

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(1) All references to our MW ownership in this prospectus include MW attributable to projects under construction, which totaled 616 MW at December 31, 1997, 284 MW at December 31, 1998, 252 MW at December 31, 1999, and 383 MW at March 31, 2000.

We intend to continue our growth through a combination of targeted acquisitions in selected core markets, the expansion or repowering of existing facilities and the development of new greenfield projects. To prepare for expansion, repowering and greenfield opportunities, we recently agreed to purchase 16 turbine generators from GE Power Systems and two turbine generators from Siemens Westinghouse over a six year period commencing in 2001. These new turbines, which we expect to install at domestic facilities, will have a combined capacity of approximately 3,300 MW.

In addition to our power generation projects, we also have interests in district heating and cooling systems and steam generation and transmission operations and landfill gas generation. Our thermal and chilled water businesses, with operations in Minnesota, California and Pennsylvania, have a steam and chilled water capacity equivalent to approximately 1,204 MW. We believe that, through our subsidiary NEO Corporation, we are also one of the largest landfill gas generation companies in the United States, extracting methane from landfills to generate electricity. NEO owns 30 landfill gas collection systems and has 55 MW of net ownership interest in related electric generation facilities. NEO also has 35 MW of net ownership interests in 18 small hydroelectric facilities.

MARKET OPPORTUNITY

The power industry is one of the largest industries in the world, accounting for approximately $200 billion in annual revenues and approximately 800,000 MW of installed generating capacity in the United States alone. The generation segment of the industry historically has been characterized by regulated electric utilities producing and selling electricity to a captive customer base. However, the power generation market has been evolving from a regulated market based upon cost of service pricing to a non-regulated competitive market. We believe that the power industry will continue to undergo substantial restructuring over the next several years and will experience significant growth in the future.

As of January 2000, 22 states had enacted legislation to restructure their electric utility industries, four additional state public utility commissions had issued comprehensive restructuring orders and 20 additional states had active legislative or regulatory processes underway to study restructuring and propose

implementing legislation. As a result, from January 1, 1997 through December 31, 1999, approximately 70,000 MW of power generating capacity in the United States had been sold or transferred by regulated electric utilities to independent power producers. We expect in excess of 70,000 additional MW of power generating capacity in the United States to be sold to independent power producers by the end of 2002.

We believe that increasing demand and the need to replace old and inefficient generation facilities will create a significant need for additional power generating capacity throughout the United States. In our view, these factors combined with recent restructuring legislation provide an attractive domestic environment for an independent power producer like us with a history of successfully developing, acquiring and operating power generation facilities.

Outside of the United States, many governments in developed economies are privatizing their utilities and developing regulatory structures that are expected to encourage competition in the electricity sector, having realized that their energy assets can be sold to raise capital without hindering system reliability. In developing countries, the demand for electricity is expected to grow rapidly. In order to satisfy this anticipated increase in demand, many countries have adopted active government programs designed to encourage private investment in power generation facilities. We believe that these market trends will continue to create opportunities to acquire and develop power generation facilities globally.

OUR HISTORY

We have been acquiring and developing power generation facilities since 1989, when we were formed as a wholly-owned subsidiary of Northern States Power to take advantage of opportunities in the independent power market that had developed as a result of economic factors and legal and regulatory changes in the United States and throughout the world. During the early 1990s, we gained experience in acquiring interests in and operating smaller domestic generation facilities and established our landfill gas, resource recovery and district heating and cooling businesses.

In 1993 we began focusing our development efforts outside the United States in response to the growing trend among foreign governments to privatize government-owned electric utility assets. We capitalized on our senior management's background and experience with our parent company, which has an excellent reputation as an owner and operator of coal-fired power plants; this, combined with Northern States Power's strong track record on environmental issues, was instrumental in our success in early global privatization initiatives in Germany and Australia. Since that time, we have gained experience in the development and operation of gas-fired power plants and have established an international reputation as a reliable and experienced owner and operator of power plants, which has allowed us to enjoy continued success in selected markets globally.

In the mid-1990s, the international privatization trend was augmented by electric utility restructuring in the United States. As regulators began opening domestic markets to competition and electric utilities began selling their electric generation assets, we refocused a significant portion of our development and acquisition efforts on independent power projects in the United States with a goal of becoming a significant owner of generation assets in certain core markets. Since January 1, 1997, we have acquired approximately 10,489 MW of power generating capacity in the United States: 7,025 MW in our Northeast region, 1,888 MW in our South Central region, and 1,576 MW in our West Coast region. We continue to pursue targeted acquisition opportunities in our core United States markets. In addition, in January 2000 we agreed to purchase 1,875 MW of power generation assets in the Mid-Atlantic United States from Conectiv. We expect to complete this acquisition during the fourth quarter of 2000 subject to receipt of required regulatory approvals.

During the 1990s, we also expanded our landfill gas, resource recovery and district heating and cooling businesses. These businesses differentiate us as an independent power producer experienced in diverse fuels and alternative energy. We believe we are one of the largest district heating and cooling providers in the United States and one of the largest landfill gas operators in the United States.

As the table below indicates, our management team has substantial experience in the electric utility and independent power businesses gained at NRG, Northern States Power and, in the case of Keith G. Hilless, at the Queensland Transmission and Supply Corporation and at the Queensland Electricity Commission in Australia.

NAME	CURRENT POSITION	YEARS WITH NRG	YEARS OF EXPERIENCE IN ELECTRIC GENERATION INDUSTRY
David H. Peterson.............	Chairman of the Board, President, Chief Executive Officer and Director	11	36
Leonard A. Bluhm..............	Executive Vice President and Chief Financial Officer	9	28
Keith G. Hilless..............	Senior Vice President, Asia Pacific	3	8
Craig A. Mataczynski..........	Senior Vice President, North America	6	17
John A. Noer..................	Senior Vice President	1	32
Ronald J. Will................	Senior Vice President, Europe	8	39

OUR INDEPENDENT POWER GENERATION BUSINESS

DOMESTIC

Our near-term domestic development and acquisition plans are focused on core markets that we consider to have attractive business fundamentals and where we believe we have the ability to achieve the scale needed to enhance our long-term profitability. Our current core domestic markets are the Northeast, South Central and West Coast regions of the United States. The table that follows summarizes our domestic power generation operations in these core markets.

UNITED STATES REGIONS	STATES OF OPERATION	PRIMARY FUELS	TOTAL CAPACITY (MW)	OUR NET OWNERSHIP INTEREST (MW)
Northeast.....................	Connecticut, Maine, Massachusetts, New Jersey, New York and Pennsylvania	Gas, Coal and Oil	7,602	7,099
South Central.................	Louisiana, Illinois and Oklahoma	Gas and Coal	2,832	2,138
West Coast....................	California	Gas and Coal	3,151	1,603
Total Domestic..............			13,585	10,840

Upon completion of our acquisition of power generation assets from Conectiv, we intend to establish the Mid-Atlantic region as our fourth domestic core market.

INTERNATIONAL

In selected global markets, we have pursued development and acquisition opportunities in those countries in which we believe that the legal, political and economic environment is conducive to foreign investment. We are presently focusing our international development activities in the United Kingdom, Central Europe, Turkey, Australia and, to a lesser extent, Latin America.

The table that follows describes our existing international power generation operations.

GLOBAL MARKETS	COUNTRIES OF OPERATION	PRIMARY FUELS	TOTAL CAPACITY (MW)	OUR NET OWNERSHIP INTEREST (MW)
Australia......................	Australia	Coal, Landfill Gas and Methane	4,146	1,312
Europe.........................	Czech Republic, Germany and United Kingdom	Coal and Gas	2,642	1,223
Latin America..................	Bolivia, Colombia, Guatemala, Honduras, Jamaica and Peru	Hydro, Gas, Coal, Oil and Geothermal	1,078	186
Total International..........			7,866	2,721

STRATEGY

Our vision is to be a well-positioned, top three generator of power in selected core markets. Central to this vision is the pursuit of a well-balanced generation business diversified in terms of geographic location, fuel type and dispatch level. Currently, 80% of our generation is located in the United States in three core markets: our Northeast, South Central and West Coast regions. With our diversified asset base, we seek to have generating capacity available to back up any given facility during its outages, whether planned or unplanned, while having ample resources to take advantage of peak power market price opportunities and periods of constrained availability of generating capacity, fuels and transmission. The following charts illustrate our diversity:

GEOGRAPHIC LOCATION(1)

U.S.	EUROPE	AUSTRALIA	OTHER
80	9.00	10.00	1.00

PRIMARY FUEL TYPE(1)(2)

COAL	GAS	OIL	OTHER
35	37	26	2

DISPATCH LEVEL(3)

PEAKING	INTERMEDIATE	BASE-LOAD
41	19	40

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(1) Based upon MW of net ownership interest as of March 31, 2000

(2) Several of our generation facilities, constituting approximately 3,900 MW of generating capacity, are capable of utilizing more than one fuel, which can be switched as fuel prices fluctuate.

(3) Estimated for 2000 based upon historic dispatch data. We define "base-load" as facilities that we expect to operate greater than 60% of the year, "intermediate" as facilities that we expect to operate between 20% and 60% of the year and "peaking" as facilities that we expect to operate less than 20% of the year, assuming utilization of primary fuel type.

Our strategy is to capitalize on our acquisition, development and operating skills to build a balanced, global portfolio of power and thermal generation assets. We intend to implement this strategy by continuing an aggressive, but thoughtful, acquisition program and accelerating our development of expansion projects at existing facilities and projects at new sites, also known as "greenfield development". We believe that our operational skills and experience give us a strong competitive position in the unregulated generation marketplace.

We have organized our operations geographically such that inventories, maintenance, backup power supply and other operational functions are pooled within a region. This approach enables us to realize cost savings and enhances our ability to meet our facility availability goals. Our availability goals are not driven by traditional benchmarks, such as daily or annual availability, but are focused on each facility's

availability during periods when power prices are significantly above the variable cost of producing power at that facility -- what we call "in-market" availability.

By leveraging the talents of our regional management teams, focusing on our regional market expertise and operating and utilizing our asset base on a regional rather than a project basis, we believe we can best position ourselves for long-term profitability. Achieving "critical mass" in core markets should allow us to capitalize on opportunities available in those markets.

We do not own nor do we have any present intention to own any interest in nuclear generation facilities.

DOMESTIC

The domestic power generation market is evolving from a regulated, utility dominated market based upon cost-of-service pricing to an independent power generation market based on competitive market pricing. While most domestic generation capacity is still utility owned and subject to cost-of-service regulation, we expect the evolution to continue as regulated utility power generation assets are divested to non-regulated generators. In addition, we expect that a significant share of the new generation capacity that is built to serve increasing demand and to replace less efficient facilities will be developed and owned by independent power producers like us.

In order to position ourselves for growth in this transitioning market, we have decided to focus our near-term domestic development and acquisition plans on our existing three core markets, our Northeast, South Central and West Coast regions, and to add the Mid-Atlantic region as our fourth core market upon closing of our planned acquisition from Conectiv. We believe that attractive business fundamentals and growth opportunities exist that will enable us to pursue a top three position in each of these markets. We will consider domestic projects outside of these markets if we believe that an opportunity exists to create a new core market or that the expected returns from a particular project warrant an investment.

We have been active in acquiring assets from utility generation divestiture programs and have focused on the following factors and characteristics in evaluating potential acquisitions:

- cost of competing power generation in the relevant markets;

- assets that provide diversity in terms of dispatch level, fuel source and access to wholesale power markets within a region;

- assets in high priced or transmission constrained markets;

- assets that allow for the sale of multiple power generation products, including energy, capacity and ancillary services;

- assets that can support our other regional assets or have the potential to sell into attractive adjacent markets;

- assets that are being sold with initial transition power purchase agreements to stabilize cash flows and earnings during our initial years of ownership; and

- assets that provide opportunities for future capacity expansion or repowerings.

Once we have acquired one or more power plants in a given market, we will then look to build additional capacity in such market as appropriate by acquiring additional power generation facilities, expanding or repowering facilities at existing sites or through greenfield development. The 16 new turbines that we recently contracted to purchase from GE, representing approximately 3,000 MW of capacity, and the two 135 MW turbines being built by Siemens Westinghouse will be the foundation for our domestic development program.

INTERNATIONAL

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 have 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. Governments have taken a variety of approaches to encourage the development of competitive power markets, from awarding long-term contracts for energy and capacity to purchasers of power generation to creating competitive wholesale markets for selling and trading energy, capacity and related products.

We believe that there will be significant opportunities to invest in attractive projects in international markets. Based upon our assessment of market opportunities and our portfolio risk management criteria, we intend to leverage our reputation, experience and expertise in order to acquire foreign assets in selected countries. As market opportunities develop, we expect that our international strategy will be consistent with our domestic core market strategy in terms of geographic, fuel and dispatch diversification. We believe operating and asset diversity will allow us to reduce business and market risks, while positioning us to take advantage of market opportunities, including peak power market price opportunities and periods of constrained availability of generating capacity, fuels and transmission.

To manage our international asset portfolio risks, we utilize a portfolio risk management discipline based upon country risk, as identified by an independent, internationally recognized organization. This portfolio tool, which has been endorsed by our board of directors, requires that we manage our entire portfolio of generation capacity to maintain a high quality, weighted average, equivalent country risk. Using this tool, we are able to monitor the exposure we are taking in emerging markets to maintain an appropriate balance in our asset portfolio.

We are presently focusing our international development in the United Kingdom, Central Europe, Turkey, Australia and, to a lesser extent, Latin America. In the future, we will consider international projects outside of these markets if we believe that an opportunity exists to create a new core market or that the expected returns from a particular project warrant an investment.

We expect to acquire or develop most international projects on a joint venture basis to enable us to share the risks associated with the acquisition and development of larger projects. Joint acquisition and development of future projects also should further reduce our financial risk by allowing us to build a more diversified portfolio of projects. Where appropriate, we will include a local or host country partner or a partner with substantial experience in the area. By doing so, we expect to gain a number of advantages, including technical expertise, greater knowledge of and experience with the political, economic, cultural and social conditions and commercial practices of the region or country where the project is being developed, and the ability to leverage our skilled personnel and financial resources. Among other things, a local partner may also assist in obtaining financing from local capital markets, building political and community support for the project and obtaining local regulatory approvals.

HOW WE SELL OUR GENERATING CAPACITY AND ENERGY

A facility's revenue under a power purchase agreement usually consists of two payments: energy and capacity. Energy payments, which are intended to cover the variable costs of electric generation, such as fuel costs and variable operation and maintenance expenses, are normally based on a facility's net electrical output measured in kilowatt hours, with payment rates either fixed or indexed to fuel costs. Capacity payments, which are generally intended to provide funds for the fixed costs incurred by the facility, such as debt service on the project financing and an equity return, are normally calculated based on the net electrical output or the declared capacity of a facility and its availability.

Our operating revenues are derived primarily from the sale of electrical energy, capacity and other energy products from our power generation facilities. Revenues from these facilities are received pursuant to:

- long-term contracts of more than one year including:

  - power purchase agreements with utilities and other third parties (generally 2-25 years);

  - standard offer agreements to provide load serving entities with a percentage of their requirements (generally 4-9 years); and

  - "transition" power purchase agreements with the former owners of acquired facilities (generally 3-5 years).

- short-term contracts or other commitments of one year or less and spot sales including:

  - spot market and other sales into various wholesale power markets; and

  - bilateral contracts with third parties.

Our objective is to mitigate variability in our earnings by having approximately 40-70% of our capacity contracted for under contracts greater than one year, generally seeking to enter into contracts with lengths of 1-5 years, selling half of our remaining capacity in the forward market for 30-365 days, and selling the other half of our remaining capacity in the spot market to capture opportunities in the market when prices are higher. By following this strategy, we seek to achieve positive, stable returns while retaining the flexibility to capture premium returns when available.

We derived approximately 36% of our 1999 revenues from two customers: Consolidated Edison Company of New York (17%) and Niagara Mohawk Power Corporation (19%). We sell energy and capacity to these customers under transition agreements expiring in 2002 and 2003, respectively. For the first quarter of 2000, we derived approximately 54.8% of our revenues from three customers: Connecticut Light & Power (26.5%), Niagara Mohawk Power Corporation (16.2%) and Consolidated Edison Company of New York (12.1%).

POWER MARKETING AND FUEL PROCUREMENT

Our energy marketing subsidiary, NRG Power Marketing, Inc., was formed in 1997 to maximize the utilization of and return from our generation assets and to mitigate the risks associated with those assets. This subsidiary markets energy and energy related commodities, including electricity, natural gas, oil, coal and emission allowances. By using internal resources to acquire fuel for and to market electricity generated by our domestic facilities, we believe we can secure the best pricing available in the markets in which we sell power and enhance our ability to compete. NRG Power Marketing provides a full range of energy management services for our generation facilities in our Northeast and South Central regions. These services are provided under power sales and agency agreements pursuant to which NRG Power Marketing manages the sales and marketing of energy, capacity and ancillary services from these facilities and also manages the purchase and sales of fuels and emission allowances needed to operate these facilities.

NRG Power Marketing operates within strict limits, typically selling only our available capacity and not engaging in any speculative activity by selling in excess of what we reasonably believe our facilities are capable of producing or will produce. The overall objective of our power marketing activities is to achieve an appropriate rate of return on our generation asset portfolio without taking on any undue risks.

In order to achieve our objectives, we have assembled an experienced team. NRG Power Marketing managerial employees have an average of 6-7 years of power marketing or similar trading experience. In addition, we have taken steps to align the interest of the power marketing staff with the overall performance of our generation assets by basing their incentive compensation primarily upon the success and profitability of our generation facilities.

In an effort to maximize our returns, we manage our power marketing for our 100% owned domestic assets centrally from our Minneapolis headquarters. We operate a trading floor, from which we monitor power and fuel prices, weather conditions and other factors affecting our business in each of our core markets. For example, we have a Northeast desk to manage power marketing for our Northeast assets. This desk is further divided by the three power pools in that region, namely, the Pennsylvania, New Jersey and Maryland power pool, the New England power pool and the New York power pool.

Although we have entered into a partnership with Dynegy Power Corporation for the marketing of power from our West Coast generation assets, our strategy and overall objectives remain the same. Accordingly, Dynegy is limited to sales that can be covered by the West Coast facilities and cannot enter

into any speculative trades and sell more than the available capacity from these facilities. In addition, Dynegy cannot enter into an agreement for longer than a 30-day period without our approval.

In Europe, our first project not covered by long-term agreements is Killingholme. Our strategy in Europe is similar to our strategy in the United States; a regional desk has been established in the United Kingdom and a central trading floor will be established as we continue to grow in Europe.

NRG Power Marketing handles fuel procurement and trading of emissions allowances in order to support our overall needs. Generally we seek to hedge prices for 50% to 70% of our expected fuel requirements during the succeeding 12 to 24 month period. This provides us with certainty as to a portion of our fuel costs while allowing us to maintain flexibility to address lower than expected dispatch rates and to take advantage of the dual fuel capabilities at many of our facilities.

NRG Power Marketing conducts its activities in accordance with risk management guidelines approved by the NRG Power Marketing board of directors, which has primary responsibility for oversight of NRG Power Marketing activities. The members of the NRG Power Marketing board of directors are our Chairman and Chief Executive Officer, Senior Vice President -- North America, and our General Counsel. NRG Power Marketing reports monthly to our Financial Risk Management Committee, which consists of our Chief Financial Officer, Treasurer, Controller, Senior Vice President -- North America and Northern States Power's Treasurer. The trading authority of each of our power marketing employees is determined by the position they hold. For example, contract administrators and fuel managers are limited to forward positions of up to one month, with a per transaction risk limit of $350,000. Transactions that would exceed these limits must receive varying levels of advance approvals. Transactions with a term of over one year and a risk greater than $1.25 million need to be approved by the NRG Power Marketing board. Our risk management guidelines also require that our treasury department perform a credit review, and approve all counter parties, prior to NRG Power Marketing entering into transactions with such counter parties. Our risk management guidelines also require that our treasury department approve in advance credit limits for all counter parties.

We do not engage in speculative trading, thus all transactions are for physical delivery of the particular commodity for the specified period. These physical delivery transactions may take the form of fixed price, floating price or indexed sales or purchases, and options on physical transactions, such as puts, calls, basis transactions and swaps, are also permitted. Contracts for the transmission and transportation of these commodities are also authorized, as necessary, in order to meet physical delivery requirements and obligations. All forward sales and purchases of electricity and fuel are reported to the board of directors of NRG Power Marketing and to our Financial Risk Management Committee. In accordance with the risk management guidelines, no more than 50% of the uncommitted energy or capacity of any facility will be sold forward without the approval of the board of directors of NRG Power Marketing. Violation by any employee of any of the risk management guidelines is grounds for immediate termination of employment.

PLANT OPERATIONS

Our success depends on our ability to achieve operational efficiencies and high availability at our generation facilities. In the new unregulated energy industry, minimizing operating costs without compromising safety or environmental standards while maximizing plant flexibility and maintaining high reliability is critical to maximizing profit margins. Our operations and maintenance practices are designed to achieve these goals.

Accordingly, we place a high level of importance on maximizing the operational performance and availability of our generation assets. Our availability goals are not driven by traditional benchmarks, such as daily or annual availability, but are focused on each facility's availability during periods when power prices are significantly above the variable cost of producing power at that facility -- what we call "in-market" availability.

Our overall corporate strategy of establishing a top three presence in certain core markets is in part driven by our operational strategy. While our approach to plant management emphasizes the operational

autonomy of our individual plant managers and staff to identify and resolve operations and maintenance issues at their respective facilities, we are also implementing a regional shared practices system in order to facilitate the exchange of information and best practices among the plants in our various regions. We have organized our operations geographically such that inventories, maintenance, backup and other operational functions are pooled within a region. This approach enables us to realize cost savings and enhances our ability to meet our facility availability goals. Plant supervisors and staff within core markets and across our company typically participate in weekly conference calls in order to discuss operational issues and share best practices.

We have a long track record of excellence in operating a diverse portfolio of generation assets. We currently operate and maintain approximately 17,600 MW of generating capacity, approximately 9,500 MW of which we do not wholly own. We are establishing a compensation and incentive program to motivate our operations staff to realize operational efficiency and in-market availability goals. In the short time since we have closed our most recent acquisitions in the northeastern United States, we have been successful in increasing the efficiency and availability of most of these facilities while at the same time reducing the number of staff required to operate such facilities.

Another example of our successful operating performance is our Gladstone facility. Although we only own 37.5% of this facility, we are the sole operator and receive an annual operating fee and are eligible to receive a monthly operating performance bonus for achieving plant availability targets. We have earned performance bonuses in a majority of the months since our acquisition of this facility in March 1994.

At facilities where we are an equity holder, but do not have operational responsibility, we typically require that we have a seat on a management committee or an operational committee. Through these positions, we are able to be kept abreast of plant status, pose questions and receive timely responses on pressing operations issues. At various times, we have used our technical personnel or we have contracted to use Northern States Power's personnel to provide consulting assistance for these projects.

Finally, safety is a key area of concern to us. We believe that the most efficient and profitable performance of our facilities can only be accomplished within a safe working environment for our employees. Our compensation and incentive program includes safety as a factor in evaluating our employees, and we have a well-developed reporting system to track safety and environmental incidents at our facilities.

MANAGEMENT, ORGANIZATIONAL AND CORPORATE DEVELOPMENT STAFF STRUCTURE

We have established three major corporate regions, North America, Europe and Australia, and have placed senior vice presidents in charge of each. Further, we have subdivided the North American and European generation business regions as follows: the North American business into Northeast, South Central and West Coast regions and the European business into the United Kingdom and Central Europe regions. The senior vice presidents and regional staff of each region are responsible for the full spectrum of development activities as well as for asset optimization within their region.

Our regional structure promotes market expertise and knowledge within our core markets. Each regional team carefully evaluates greenfield and acquisition opportunities against risk and return guidelines determined by management. Ten years of development experience have resulted in thorough and efficient due diligence procedures, whereby our cross-functional teams focus on the particular issues that are most critical to each project under consideration. If an opportunity meets the requirements of the regional management team and will strengthen our regional portfolio, our senior management must review the project before it is presented to our board of directors.

INDEPENDENT POWER GENERATION PROJECTS -- DOMESTIC

Most of our domestic projects are grouped under three regional holding companies corresponding to our domestic core markets. In order to better manage our domestic projects and to more effectively develop new projects in these regions, we have recently established regional offices in Pittsburgh,

Pennsylvania (Northeast region), Baton Rouge, Louisiana (South Central region) and San Diego, California (West Coast region). Upon the completion of the Conectiv asset acquisition, it is expected that those assets will be grouped into a new Mid-Atlantic region.

We intend our generation facilities within each region to be operated as a separate business. This regional portfolio structure will allow us to coordinate the operations of our assets to take advantage of regional opportunities, reduce risks related to outages, whether planned or unplanned, and pursue expansion plans on a regional basis.

NORTHEAST REGION

We own approximately 7,100 MW of generating capacity in the Northeast United States, primarily in New York, New Jersey, Connecticut, Massachusetts and

Pennsylvania. These generation facilities are well diversified in terms of dispatch level (base-load, intermediate and peaking), fuel type (coal, natural gas and oil) and customers. In addition, we believe certain of our facilities and facility sites in the Northeast provide opportunities for repowering or expansion of existing generating capacity.

Our Northeast facilities are generally competitively positioned within their respective market dispatch levels with favorable market dynamics and locations close to the major load centers in the New York Power Pool and New England Power Pool. For example, the Arthur Kill and Astoria gas turbine facilities are located in the New York City in-city market and represent approximately 20% of the installed capacity inside this transmission constrained area. Load serving entities in the New York City in-city market must currently contract for 80% of their requirements from in-city resources. We believe there is presently limited potential to construct new in-city generation capacity or to gain transmission access to other generating capacity.

We currently sell a portion of the energy and capacity generated by our assets in the Northeast region into the New York Power Pool. The independent system operator for the New York Power Pool has recently imposed price limitations on certain ancillary services sold in this market, and has sought authority from FERC to adjust the market-clearing prices for these services on a retroactive basis. We have joined several other independent power producers in New York in filing a claim with FERC challenging these actions. If the independent system operator prevails, our revenues from ancillary services sold in the New York Power Pool could be substantially reduced. Although we would attempt to adjust our business operations to mitigate the future impacts of such a ruling, the potential negative impacts on our revenues for the first quarter of 2000 would include the potential refund of approximately $8.0 million of revenues collected in February 2000 and the inability to collect approximately $8.2 million included in revenues, but not yet collected, for March 2000.

To achieve financing, cost and administrative advantages we have pooled our 100% owned Northeast generation assets into a regional holding company, NRG Northeast Generating LLC. Through NRG Northeast Generating, we financed a significant portion of the purchase prices for the separate acquisitions of these generation facilities by means of a $750 million debt financing, which was completed in February 2000.

Through our ownership of 20% of Cogeneration Corporation of America, our Northeast assets also include several small, indirectly held, interests in facilities located in New York, New Jersey and Pennsylvania.

The following table summarizes our Northeast generation assets:

NAME AND LOCATION OF FACILITY	PURCHASER/POWER MARKET	TOTAL MW	OUR OWNERSHIP INTEREST	OUR NET OWNERSHIP INTEREST (MW)	FUEL TYPE
Oswego, New York	NIMO/NYISO	1,700	100.00%	1,700	Oil/Gas
Huntley, New York	NIMO/NYISO	760	100.00%	760	Coal
Dunkirk, New York	NIMO/NYISO	600	100.00%	600	Coal
Arthur Kill, New York	Con Ed/NYISO	842	100.00%	842	Gas
Astoria Gas Turbines, New York	Con Ed/NYISO	614	100.00%	614	Gas
Somerset, Massachusetts(1)	EUA/NEPOOL/ISO-NE	229	100.00%	229	Coal/Oil
Middletown, Connecticut	NEPOOL/NYPP/ISO-NE	856	100.00%	856	Oil/Gas
Montville, Connecticut	NEPOOL/NYPP/ISO-NE	498	100.00%	498	Gas/Oil
Norwalk, Connecticut	NEPOOL/NYPP/ISO-NE	353	100.00%	353	Oil
Devon, Connecticut	NEPOOL/NYPP/ISO-NE	401	100.00%	401	Gas/Oil
Connecticut Turbines, Connecticut	NEPOOL/NYPP/ISO-NE	127	100.00%	127	Oil
CogenAmerica (Grays Ferry), Penn.	PECO Energy	150	10.00%	15	Gas/Oil
CogenAmerica (Parlin), New Jersey	Jersey Central Power & Light	122	20.00%	24	Gas/Oil
CogenAmerica (Newark), New Jersey	Jersey Central Power & Light	54	20.00%	11	Gas/Oil
Other(2)	Various	296	Various	69	Various
Total		7,602		7,099	

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(1) Includes 69 MW of deactivated reserve.

(2) Includes 69 MW of net ownership interest in seven projects.

The following generation facilities were purchased together in bundled transactions:

- Astoria and Arthur Kill facilities for $505 million;

- Huntley and Dunkirk facilities for $355 million; and

- Middletown, Montville, Norwalk, Devon and Connecticut combustion turbine facilities for $519 million.

The purchase prices for each of the facilities described below, other than the Oswego and Somerset facilities, reflect an allocation of the purchase price paid in the bundled transaction in which the facility was acquired.

Oswego Facility. The Oswego facility was acquired from Niagara Mohawk Power Corporation and Rochester Gas & Electric Company in October 1999 for a purchase price of $85 million. The Oswego facility, located in Oswego, New York, is a natural gas/oil-fired, peaking plant consisting of two units with a total capacity of 1,700 MW. The Oswego facility is currently a source of excess emission allowances that can be utilized at other facilities. We expect to operate this facility as a peaking facility. In connection with this acquisition, we entered into a four-year transition power purchase agreement with Niagara Mohawk Power under which we agreed to sell to Niagara Mohawk Power 100% of the capacity of one unit, an option for up to 40% of the capacity of the second unit, and an option to purchase a nominal amount of energy from both units.

Huntley Facility. The Huntley facility was acquired from Niagara Mohawk Power in June 1999 for a purchase price of $155.7 million. The Huntley facility, located near Buffalo, New York, is a coal-fired, base-load facility consisting of six units with a total capacity of 760 MW. The Huntley facility is among the lowest cost fossil fuel plants that sell into the New York Power Pool. We plan to operate it as a base-load facility. In connection with the acquisition of this facility, we entered into four-year transition power purchase agreements under which we agreed to sell to Niagara Mohawk Power 100% of the capacity of, and an option to purchase up to 45% of the annual energy output from, certain units of the Huntley facility.

Dunkirk Facility. The Dunkirk facility was acquired from Niagara Mohawk Power in June 1999 for a purchase price of $199.3 million. The Dunkirk facility, located in Dunkirk, New York, is a coal-fired, base-load facility consisting of four units with a total capacity of 600 MW. The Dunkirk facility is among the lowest variable cost fossil fuel plants that sell into the New York Power Pool. We plan to operate it as a base-load facility. In connection with the acquisition of this facility, we entered into four-year transition power purchase agreements under which we agreed to sell to Niagara Mohawk Power 100% of the capacity of, and an option to purchase up to 39% of the annual energy output from, the Dunkirk facility.

Arthur Kill Facility. The Arthur Kill facility was acquired from Consolidated Edison Company of New York, Inc. in June 1999 for a purchase price of $395.6 million. The Arthur Kill facility, located in Staten Island, New York, is a natural gas/oil-fired, intermediate/peaking plant consisting of three units with a total capacity of 842 MW.

Astoria Gas Turbines. The Astoria gas turbines were acquired from Consolidated Edison in June 1999 for a purchase price of $109.5 million. The Astoria facility, located in Queens, New York, is a gas/ liquid fuel-fired, peaking plant consisting of 11 units with a total capacity of 614 MW.

In connection with the acquisition of the Arthur Kill and the Astoria facilities, we entered into transition capacity sales agreements under which we agreed to sell to Consolidated Edison at a fixed price, during certain periods, up to 100% of the capacity of each of the Arthur Kill and Astoria facilities for a transition period ending on the earlier of (a) December 31, 2002 or (b) the date such facility receives notice from the independent system operator in New York State that none of the electric generation capacity of such facility is required for meeting the installed capacity requirements in New York City.

Somerset Facility. The Somerset facility was acquired from Montaup Electric Company, an affiliate of Eastern Utilities Associates, in April 1999 for a purchase price of $55 million. The Somerset facility, located in Somerset, Massachusetts, is an oil/coal-fired, base-load/peaking facility consisting of three units with a total capacity of 229 MW (160 MW of which is currently operational). The Somerset facility provides low variable cost capacity, strategically positioned to sell power into the New England Power Pool. We intend to operate this facility as a peaking and base-load facility, depending on market conditions. In connection with this acquisition, we also entered into a wholesale standard offer service agreement under which we are obligated to provide approximately 30% of the energy and capacity requirements of certain affiliates of Eastern Utilities Associates, which we estimate to be approximately 275 MW at peak requirement, until December 31, 2009. The difference between this service requirement and our operational capacity at Somerset is made up by a combination of power supplied by our other Northeast facilities and purchased power.

Connecticut Facilities

In connection with the acquisition in December 1999 of the Middletown, Montville, Norwalk, Devon and Connecticut combustion turbine facilities from Connecticut Light & Power, we entered into a four-year standard offer service wholesale sales agreement with Connecticut Light & Power pursuant to which we will supply to Connecticut Light & Power at fixed prices a portion of Connecticut Light & Power's aggregate retail load. The quantity of power to be supplied is equal to 35% of Connecticut Light & Power's standard offer service load during calendar year 2000, 40% during calendar years 2001 and 2002, and 45% during calendar year 2003. We estimate that 45% of Connecticut Light & Power's standard offer service load in 2003 will be approximately 2,000 MW at peak requirement. The agreement terminates on December 31, 2003. This contract is valued at $1,700 million. We believe the Connecticut facilities are strategically positioned for sales into the New England Power Pool and have a competitive advantage on transmission charges; we will operate these facilities as peaking and intermediate facilities to take advantage of market volatility.

Middletown Facility. The Middletown facility was acquired for a purchase price of $92.5 million. The Middletown facility, located in Middletown, Connecticut, is a natural gas/oil-fired intermediate/ peaking plant consisting of four units with a total capacity of 856 MW.

Montville Facility. The Montville facility was acquired for a purchase price of $216.2 million. The Montville facility, located in Uncasville, Connecticut, is a natural gas/oil-fired intermediate/peaking load plant consisting of four units with a total capacity of 498 MW.

Norwalk Facility. The Norwalk facility was acquired for a purchase price of $75.0 million. The Norwalk facility, located in Norwalk, Connecticut, is an oil-fired, intermediate/peaking load plant consisting of three units with a total capacity of 353 MW.

Devon Facility. The Devon facility was acquired for a purchase price of $113.3 million. The Devon facility, located in Milford, Connecticut, is a natural gas/oil-fired, intermediate/peaking load facility consisting of seven units with a total capacity of 401 MW.

Connecticut Combustion Turbines. These six combustion turbines were acquired for a purchase price of $22.3 million. These facilities, located in Branford, Torrington Terminal, Franklin Drive and Cos Cob, Connecticut, are oil-fired, peaking units consisting of six units with a total capacity of 127

MW.

SOUTH CENTRAL REGION

We own approximately 1,888 MW of generating capacity in the South Central United States, primarily in Louisiana. Our South Central generation assets consist primarily of our net ownership of 1,708 MW of power generation facilities in New Roads, Louisiana that we acquired in March 2000 as a result of a competitive bidding process following a Chapter 11 bankruptcy. We refer to these facilities as the Cajun facilities. We believe that the Cajun facilities and related infrastructure provide significant opportunities for expanding our generation capacity in the region. We intend to further augment our recent acquisition of the Cajun facilities in Louisiana with additional projects in the area.

To achieve financing, cost and administrative advantages we formed a regional holding company, NRG South Central Generating LLC, to hold our ownership interest in Louisiana Generating LLC, the owner of the Cajun facilities. Through NRG South Central Generating, we financed a significant portion of the purchase price for the Cajun facilities by means of an $800 million debt financing completed in March 2000.

Through our ownership of 20% of Cogeneration Corporation of America, our South Central assets also include two small, indirectly held interests in facilities located in Oklahoma and Illinois.

The following table summarizes our South Central generation assets:

NAME AND LOCATION OF FACILITY	PURCHASER/POWER MARKET	TOTAL MW	OUR OWNERSHIP INTEREST	OUR NET OWNERSHIP INTEREST (MW)	FUEL TYPE
Big Cajun I, Louisiana					
Unit 1	Cooperatives/Municipals	110	100.00%	110	Gas
Unit 2	Cooperatives/Municipals	110	100.00%	110	Gas
Big Cajun II, Louisiana					
Unit 1	Cooperatives/Municipals	575	100.00%	575	Coal
Unit 2	Cooperatives/Municipals	575	100.00%	575	Coal
Unit 3	Cooperatives/Municipals	575	58.00%	338	Coal
Sterlington, Louisiana(1)	Various	200	100.00%	200	Gas
Rocky Road Power, Illinois(2)	ECAR/MAIN	350	50.00%	175	Gas
Other(3)	Various	337	Various	55	Various
Total		2,832		2,138	

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(1) Under construction, expected to be phased into service between June and December 2000.

(2) Includes 100 MW expected to be in service June 2000.

(3) Includes 55 MW of net ownership interest in three facilities.

Cajun Facilities. The Cajun facilities were acquired in a competitive bidding process following a Chapter 11 bankruptcy filing by their former owner, Cajun Electric Power Cooperative, Inc. We paid

approximately $1.026 billion for these facilities. The Cajun facilities consist of 100% of two gas-fired, intermediate/peaking power generation units with a total capacity of 220 MW, which we collectively refer to as "Big Cajun I," and two coal-fired, base-load power generation units with a total capacity of 1,150 MW and a 58% interest in a third coal-fired, base-load unit with a total capacity of 575 MW, which we collectively refer to as "Big Cajun II." The Cajun facilities have benefited from an extensive maintenance program over their history and from capital expenditures in excess of $26 million from 1997 through 1999 while under the stewardship of Cajun Electric's bankruptcy trustee.

We believe the bankruptcy resulted from Cajun Electric's inability to service approximately $4,200 million in secured debt provided in part by the Rural Utilities Service of the United States Department of Agriculture, most of which was incurred as a result of the purchase by Cajun Electric of a 30% interest in the River Bend Nuclear Station Unit I, a nuclear power generation facility located in Saint Francisville, Louisiana. Cajun Electric's 30% interest in the River Bend nuclear facility was transferred to Entergy Gulf States in December 1997. We have no ownership interest in the River Bend nuclear facility or responsibility for any indebtedness of Cajun Electric to the Rural Utilities Service or otherwise.

We sell most of the energy and capacity of the Cajun facilities to 11 of Cajun Electric's former power cooperative members. Seven of these cooperatives have entered into 25-year power purchase agreements with us, and four have entered into two to four year power purchase agreements. In addition, we sell power under contract to two municipal power authorities and one investor-owned utility that were former customers of Cajun Electric. We estimate that payments under the contracts with the 11 cooperatives will account for approximately 72% of the Cajun facility's projected 2001 revenues, and that payments under the contracts with the municipal power authorities and the investor-owned utility will, in addition, account for an approximately 7% of such revenues.

Rocky Road Facility. We acquired a 50% interest in the Rocky Road facility from Dynegy in December 1999 for a purchase price of approximately $60.0 million. The Rocky Road facility, located in East Dundee, Illinois, is a gas-fired, peaking facility consisting of two units with a total capacity of 250 MW. The facility began commercial operations in June 1999 and received approval for the installation of an additional 100 MW natural gas combustion turbine in October 1999. The expansion is expected to be in service before the start of the peak summer 2000 season. This facility sells energy into the ECAR and MAIN wholesale power markets.

Sterlington Facility. The Sterlington facility is a 200 MW simple cycle, gas-fired, peaking facility under construction in Sterlington, Louisiana. Commercial operations are expected to be phased in between June and December 2000. We anticipate that the facility will sell power into five nearby power pools.

WEST COAST REGION

We own approximately 1,603 MW of generating capacity on the West Coast of the United States. Our West Coast generation assets consist primarily of a 50% interest in West Coast Power LLC and a 58% interest in the Crockett Cogeneration facility. In May 1999, we and Dynegy formed West Coast Power to serve as the holding company for a portfolio of operating companies which own generation assets in Southern California. These assets are currently comprised of the El Segundo Generating Station, the Long Beach Generating Station, the Encina Generating Station and 17 combustion turbines in the San Diego area. We believe certain of our facilities and facility sites on the West Coast provide opportunities for repowering or expansion of generating capacity.

We and Dynegy intend to utilize West Coast Power as a growth vehicle through which future investments in assets serving the California power market will be held. We believe that West Coast Power will benefit from synergies and economies of scale through a common management structure, and that it has an attractive mixture of revenue sources, including merchant and, as described below, "must-run" plants. In addition, West Coast Power has power marketing flexibility, in which a power shortage in one unit or plant can be compensated for with excess power from another unit. Dynegy is providing power marketing services to West Coast Power.

In June 1999, West Coast Power financed a significant portion of the purchase price for its assets with a five-year, $362.5 million limited-recourse bank facility secured by the limited liability company interests and project assets of the El Segundo, Long Beach and Encina facilities and the San Diego combustion turbines.

The Encina facility and the San Diego combustion turbines are currently subject to "Reliability Must-Run" agreements with the California independent system operator. These must-run agreements take the form of a call option contract under which the California independent system operator will pay a fixed capacity payment for the right to dispatch the unit, and variable costs are passed through at cost. Must-run agreements with the California independent system operator are intended to mitigate regional market power and make up for inadequate power supplies in a specific area. The must-run agreements require us to provide power and ancillary services when requested by the California independent system operator. The must-run agreements have a one-year term, which the California independent system operator may extend indefinitely for additional one-year periods. We estimate that payment made under must-run contracts will account for approximately 17% to 21% of the revenues from projects owned by West Coast Power.

The following table summarizes our West Coast generation assets:

NAME AND LOCATION OF FACILITY	PURCHASER/POWER MARKET	TOTAL MW	OUR OWNERSHIP INTEREST	OUR NET OWNERSHIP INTEREST (MW)	FUEL TYPE
El Segundo Power, California..............	Cal PX	1,020	50.00%	510	Gas
Encina, California........................	Cal PX/Must-run	965	50.00%	482	Gas
Long Beach Generating, California..........	Cal PX	530	50.00%	265	Gas
San Diego Combustion Turbines, California..............................	Cal PX/Must-run	253	50.00%	127	Gas
Crockett Cogeneration, California..........	PG&E	240	57.67%	138	Gas
Mt. Poso Cogeneration, California..........	PG&E	50	39.10%	19	Coal
Other(1)..................................	Various	93	Various	62	Various
Total.....................................		3,151		1,603	

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(1) Includes our net ownership interest in three small facilities.

El Segundo Facility. The El Segundo facility was acquired from Southern California Edison Company in April 1998 for a purchase price of $87.7 million. The El Segundo facility, located in El Segundo, California, is a gas-fired, intermediate facility consisting of four units with a total capacity of 1,020 MW. The El Segundo facility sells electricity through the California power exchange.

Encina Facility. The Encina facility was acquired from San Diego Gas & Electric in May 1999 for a purchase price of $290.5 million. The Encina facility, located in Carlsbad, California, is a gas-fired, intermediate/peaking facility consisting of six units with a total capacity of 965 MW. The Encina facility sells electricity through the California power exchange and under must-run agreements.

Long Beach Facility. The Long Beach facility was acquired from Southern California Edison in March 1998 for a purchase price of $29.8 million. The Long Beach facility, located in Long Beach, California, is a gas-fired, peaking facility consisting of nine units with a total capacity of 530 MW. The Long Beach facility sells peak electricity and ancillary services through the California power exchange.

San Diego Combustion Turbines. The San Diego combustion turbines were acquired from San Diego Gas & Electric in May 1999 for a purchase price of $69.1 million. The San Diego combustion turbines, located on seven different sites in San Diego County, California, consist of 17 combustion turbines with a total capacity of 253 MW. The combustion turbines have the ability to provide spinning reserve, black start capability, quick start capability, voltage support and quick load capability for the ancillary services market. The combustion turbines sell electricity through the California power exchange and under must-run agreements.

Crockett Cogeneration Facility. We own a 58% interest in the Crockett cogeneration facility located in Crockett, California on the San Francisco Bay. We acquired our interest in November 1997 for $46.4 million. The Crockett facility is a gas-fired facility with a total capacity of 240 MW. This facility supplies all of the refinery steam needs of the adjacent C&H Sugar Company refinery and sells capacity and energy under a modified, interim standard offer power sales agreement to Pacific Gas & Electric Company, which expires in May 2026.

Mt. Poso Cogeneration Facility. We own a 39% interest in the Mt. Poso cogeneration facility located near Bakersfield, California. We acquired an initial 22% interest in November 1997 for $14.3 million and our remaining interest in June 1998 for $4.7 million. The Mt. Poso facility is a coal-fired facility with a total capacity of 50 MW. The facility sells steam to an adjacent oil field owned by the project company and the capacity and energy are sold under a long-term, interim standard offer power sales agreement to Pacific Gas & Electric, which expires in May 2019.

PENDING MID-ATLANTIC ACQUISITIONS

In January 2000, we executed purchase agreements with subsidiaries of Conectiv to acquire 1,875 MW of coal, gas and oil-fired electric generating capacity and other assets. We will pay approximately $800 million for the assets, a portion of which will be financed by project-level debt. The assets include the BL England and Deepwater facilities in New Jersey, the Indian River facility in Delaware and the Vienna facility in Maryland, and interests in the Conemaugh (7.6%) and Keystone (6.2%) facilities in Pennsylvania. The purchase also includes excess emissions allowances. Subject to receipt of required regulatory approvals, we expect the acquisition to close in the fourth quarter of 2000. Subject to final documentation, we will sell 500 MW of capacity and associated energy to a subsidiary of Conectiv under a five-year power purchase agreement commencing upon the closing of the acquisition.

The following table summarizes the generation assets we expect to acquire from Conectiv:

NAME AND LOCATION OF FACILITY	PURCHASER/POWER MARKET	TOTAL MW	OUR OWNERSHIP INTEREST	OUR NET OWNERSHIP INTEREST (MW)	FUEL TYPE
BL England, New Jersey.........	Conectiv/PJM	447	100.00%	447	Coal/Oil
Deepwater, New Jersey..........	Conectiv/PJM	239	100.00%	239	Gas/Coal/Oil
Indian River, Delaware.........	Conectiv/PJM	784	100.00%	784	Coal
Vienna, Maryland...............	Conectiv/PJM	170	100.00%	170	Oil
Conemaugh, Pennsylvania........	Conectiv/PJM	1,711	7.55%	129	Coal
Keystone, Pennsylvania.........	Conectiv/PJM	1,711	6.17%	106	Coal
Total........................		5,062		1,875	

DOMESTIC DEVELOPMENT

We are currently pursuing a number of development projects in our core domestic markets. We have recently agreed to purchase 16 turbine generators from GE Power Systems and two turbine generators from Siemens Westinghouse over a six year period commencing in 2001. These new turbines, which we expect to install at domestic facilities, will have a combined capacity of approximately 3,300 MW.

Our development activities in the United States also include greenfield opportunities. With our partners, Salt River Project and Dynegy, we announced plans to develop an 825 MW gas-fired, combined-cycle generation facility to serve the growing demand for electricity in the greater Phoenix area. Final negotiations on project agreements are in progress and site permitting has begun.

INDEPENDENT POWER GENERATION PROJECTS -- INTERNATIONAL

AUSTRALIA

We are one of the largest independent power producers in Australia with a net ownership interest of 1,312 MW in power generation facilities. We intend to maintain our position in the market through

additional acquisitions and development of new projects. We will also look for opportunities in selected countries in the Asia Pacific region to become established within the region.

The following table summarizes our Australian generation assets:

NAME AND LOCATION OF FACILITY	POWER MARKET/ PURCHASER	TOTAL MW	OUR OWNERSHIP INTEREST	OUR NET OWNERSHIP INTEREST (MW)	FUEL TYPE
Gladstone Power Station (Queensland), Australia	QPTC; Boyne Smelter	1,680	37.50%	630	Coal
Loy Yang Power A (Victoria), Australia	Victorian Pool	2,000	25.37%	507	Coal
Collinsville (Collinsville), Australia	QPTC	192	50.00%	96	Coal
Energy Developments Limited (Various), Australia	Various	274	29.14%	79	LFG/Methane
Total		4,146		1,312	

Gladstone Facility. The Gladstone facility is a 1,680 MW coal-fired power generation facility located in Gladstone, Australia. We acquired a 37.5% ownership interest in the Gladstone facility for $64.9 million when the facility was privatized in March 1994.

We are responsible for operation and maintenance of the Gladstone facility pursuant to a 17 year operation and maintenance agreement that commenced in 1994, which includes an annual bonus based on availability targets. The Gladstone facility sells electricity to the Queensland Power Trading Corporation and also to Boyne Smelters Limited. Pursuant to an interconnection and power pooling agreement, Queensland Power is obligated to accept all electricity generated by the facility, subject to merit order dispatch, for an initial term of 35 years.

Queensland Power also entered into a 35-year capacity purchase agreement with each of the project's owners for such owner's percentage of the capacity of the Gladstone facility, excluding that sold directly to Boyne Smelters. Under the capacity purchase agreements, the facility owners are paid both a capacity and an energy charge by Queensland Power. The capacity charge is designed to cover the projected fixed costs allocable to Queensland Power, including debt service and an equity return, and is adjusted to reflect variations in interest rates. A capacity bonus is also available if the equivalent availability factor exceeds 88% on a 24 month rolling average basis, and damages are payable by the project's owners if it is less than 82% on that same basis. As of March 31, 2000, the two-year average equivalent availability factor was 88.4%.

The owners of Boyne Smelters have also entered into a power purchase agreement with each of the project's owners, providing for the sale and purchase of such owner's percentage share of capacity allocated to Boyne Smelters. The term of each of these power purchase agreements is 35 years. The owners of Boyne Smelters is obligated to pay to each of the project's owners a demand charge that is intended to cover the fixed costs of supplying capacity to Boyne Smelters, including debt service and return on equity. The owners of Boyne Smelters are also obligated to pay an energy charge based on the fuel cost associated with the production of energy from the Gladstone facility. Expansion at Boyne Smelters resulted in an increase in capacity utilization from approximately 41% in 1994 to 60% in 1999. We anticipate that the capacity utilization will increase to approximately 64% in 2000.

Recent reforms in the Queensland electricity industry arising from the introduction of the National Electricity Market have changed the regulatory framework in which the Gladstone facility operates. In particular, the existing arrangements relating to the commitment and dispatch of the facility and the supply of power to customers of the facility no longer accord with the mechanisms for buying and selling electricity in Queensland. As a result, Queensland Power and the other parties to the project agreements have entered into negotiations to alter the agreements to accomplish two goals: (1) compliance with the new framework arising from the introduction of the National Electricity Market, while ensuring that the actual operation of the facility is similar to that under the existing agreements and (2) preservation, to the extent possible, of the commercial positions of all parties. We expect amended agreements to be

finalized and signed by the end of calendar year 2000 and we believe that any amended agreements will have no impact on the risk profile or financial performance of the Gladstone facility.

Effective December 9, 1999, the Australian government reduced the corporate income tax rate. This reduction of Australian corporate income tax rates resulted in an increase in our net income related to this facility of $3.9 million for 1999.

Loy Yang Facility. We have a 25.4% interest in Loy Yang Power which owns and operates the 2,000 MW Loy Yang A brown coal fired thermal power station and the adjacent Loy Yang coal mine located in Victoria, Australia. This interest was purchased for AUS$340 million (approximately US$264.3 million at the time of the acquisition) in 1997. The power station has four units, each with a 500 MW boiler and turbo generator, which commenced commercial operation between July 1984 and December 1988. In addition, Loy Yang manages the common infrastructure facilities that are located on the Loy Yang site, which service not only the Loy Yang A facility, but also the adjacent Loy Yang B 1,000 MW power station, a pulverized dried brown coal plant, and several other nearby power stations.

The wholesale electricity market in Australia is regulated under the National Electricity Law which provides for a legally enforceable National Electricity Code which defines the market rules. The code also makes provision for the establishment of the National Electricity Market Management Company to manage the power system, maintain system security and administer the spot market. Under the rules of the National Electricity Market, the Loy Yang facility is required to sell all of its output of electricity through the competitive wholesale market for electricity operated and administered by the National Electricity Market.

In the National Electricity Market power pool system, it is not possible for a generator such as Loy Yang to enter into traditional power purchase agreements. In order to provide a hedge against pool price volatility, generators have entered into "contracts for differences" with distribution companies, electricity retailers and industrial customers. These contracts for differences are financial hedging instruments, which have the effect of fixing the price for a specified quantity of electricity for a particular seller and purchaser over a defined period. They establish a "strike price" for a certain volume of electricity purchased by the user during a specified period; differences between that "strike price" and the actual price set by the pool give rise to "difference payments" between the parties at the end of the period. Even if Loy Yang is producing less than its contracted quantity it will still be required to make and will be entitled to receive difference payments for the amounts set forth in its contracts for differences.

Loy Yang also has contracts with the Victorian distribution companies in respect of regulated customer load. These contracts, called "vesting contracts," account for approximately 64% of Loy Yang's forecasted revenue from generation, and provide some stability in Loy Yang's revenues until all these contracts expire on December 31, 2000. Loy Yang's contracts for differences are generally for a term of one to two years, and the volume of load covered by these contracts will increase as vesting contracts expire. The combination of the contracts for differences and the vesting contracts covered approximately 90% of Loy Yang's load at March 31, 2000.

Energy prices in the Victoria region of the National Electricity Market of Australia into which our Loy Yang facility sells its power have been significantly lower than we had expected when we acquired our interest in the facility. As a result, the Loy Yang project company is currently prohibited by its loan agreements from making equity distributions to the project owners. Based on our forecasted power prices, we expect that the Loy Yang project company will fail to meet required coverage ratios under its loan agreements beginning in the third quarter of 2001, which would constitute an event of default. Moreover, if market prices in Victoria continue at current levels (which are below our current power price projections) we expect that the Loy Yang project company will be unable to service its long-term debt obligations beginning in the first quarter of 2002. In either case, absent a restructuring of the project company's debt, the project company's lenders would be allowed to accelerate the project company's indebtedness. We could be required to write-off all or a significant portion of our current $250 million investment in this project as a result of such acceleration, a determination by the project company that a write-down of its assets is required or our determination that we would not be able to recover our investment in this project.

In February 2000, CMS Energy announced its intention to divest its 49.6% ownership in the Loy Yang project. CMS Energy indicated that it intended to sell its interest because the project was no longer of strategic value to its portfolio and had not met its financial expectations. The remaining partners in the Loy Yang project have rights of first refusal with respect to CMS Energy's sale of its interest.

The 1999 reduction of Australian corporate income tax rates described above resulted in a decrease in our net income related to this facility of $3.4 million for 1999.

Collinsville Facility. The Collinsville Power Station is a 192 MW coal-fired power generation facility located in Collinsville, Australia. In March 1996, we acquired a 50% ownership interest in the idled Collinsville facility for US$11.9 million when it was privatized by the Queensland State government. The Collinsville facility was recommissioned and commenced operations on August 11, 1998. We and Transfield Holdings Pty Ltd, the project's other 50% owner, have entered into an 18-year power purchase agreement with Queensland Power under which Queensland Power will pay both a capacity and an energy charge to the project's owners. The capacity charge is designed to cover the projected fixed costs allocable to Queensland Power, including debt service and an equity return. The energy charge is based on the fuel costs associated with the production of energy from the facility.

Energy Developments Limited. Energy Developments Limited, a publicly traded company listed on the Australian Stock Exchange, owns and operates approximately 274 MW of generation primarily in Australia. Between February 1997 and April 1998, we acquired a total of 14,609,670 common shares and 16,800,000 convertible, non-voting preference shares of Energy Developments. We paid a total of approximately AUS$69.1 million (US$44.5 million at the time of acquisition), or AUS$2.20 (US$1.42) per share, for the shares, which represent approximately a 29% ownership interest in Energy Developments. We have agreed to restrictions on our ability to purchase more shares or to dispose of any existing shares of Energy Developments. The preference shares do not become convertible into common shares unless a takeover bid is made for Energy Developments. In such event, if Energy Developments fails to comply with an obligation to appoint directors nominated by the owner of the preference shares, the preference shares can be converted at the option of the owner to common shares on a share-for-share basis. The common shares of Energy Developments traded at AUS$12.35 (approximately US$7.50) per share on March 31, 2000.

EUROPE

We have been a significant participant in the independent power generation markets in Germany and the Czech Republic since our entry into those markets in 1993. Our growth in Europe was also augmented in early-2000 with the acquisition of the Killingholme facility and the expected mid-2000 commencement of commercial operations at the Enfield facility, both of which are located in the United Kingdom. We intend to continue our growth efforts in these countries and to develop projects in countries such as Poland, Estonia and Turkey.

The following table summarizes our European generation assets:

NAME AND LOCATION OF FACILITY	PURCHASER/POWER MARKET	TOTAL MW	OUR OWNERSHIP INTEREST	OUR NET OWNERSHIP INTEREST (MW)	FUEL TYPE
Killingholme, UK	U.K. Electricity Grid	680	100.00%	680	Gas
Enfield, UK	U.K. Electricity Grid	396	25.00%	99	Gas
Schkopau Power Station, Germany	VEAG	960	20.95%	200	Coal
MIBRAG mbH, Germany	WESAG/MIBRAG	110	33.33%	37	Coal
MIBRAG mbH, Germany	WESAG/MIBRAG	86	33.33%	29	Coal
MIBRAG mbH, Germany	WESAG/MIBRAG	37	33.33%	12	Coal
Kladno, Phase I, Czech Republic	STE/Industrials	28	44.26%	12	Coal
Kladno, Phase II, Czech Republic	STE/Industrials	345	44.50%	154	Coal/Gas
Total		2,642		1,223	

Killingholme Facility. In March 2000, we acquired the 680 MW gas-fired Killingholme combined-cycle, baseload facility in North Lincolnshire, England from National Power plc. The purchase price was L390 million (approximately $615 million at the time of acquisition), subject to post-closing adjustments. We financed the acquisition with a 19-year non-recourse credit facility that provided for L235 million (approximately $374 million at March 31, 2000) for the costs of the acquisition and L100 million (approximately $159 million at March 31, 2000) for letters of credit and working capital needs. We are selling power from the facility into the wholesale electricity market of England and Wales. The facility has a ten and one half year contract to purchase up to 70% of its natural gas requirements from a subsidiary of Centrica plc. From January 1, 2000 through the date of the acquisition, we entered into a tolling agreement with National Power pursuant to which we received revenues based on the prevailing market prices for electricity in exchange for payments to National Power based on the incremental operating cost of the facility.

We anticipate that prices for power in the wholesale electricity market of England and Wales will decrease over the short term due to new trading rules which are expected to come into effect and increased competition in this market. This expected market trend was taken into account when we bid to acquire this facility. We have entered into short-term agreements to sell a portion of the output of the Killingholme facility, and, in the future, we intend to enter into similar short-term and long-term agreements that will provide a degree of stability to our revenues from the facility.

Enfield Facility. We hold a 25% interest in the Enfield Energy Center, a 396 MW gas-fired facility in the North London borough of Enfield, for which our net investment is expected to be approximately $10.5 million. This project was scheduled to commence commercial operation in November 1999, but due to problems in the design and manufacture of the rotors and gas turbines, has been delayed until June 2000. Although the construction contractor is contractually obligated to make certain payments to partially compensate the owners of the project for such delays, the obligation to make such payments in this situation and the amount of such payments are being disputed. Nevertheless, we expect that once the project is completed it will function as anticipated, and we do not expect this delay to have a material adverse effect on the operations or financial performance of the facility.

Schkopau Facility. In 1993, we acquired for $18.2 million an indirect 50% interest in a German limited liability company, Saale Energie GmbH, which then acquired a 41.9% interest in a 960 MW coal-fired power plant that was under construction in the East German city of Schkopau. The first 425 MW unit of the Schkopau plant began operation in January 1996, the 110 MW turbine in February 1996, and the second 425 MW unit in July 1996. The coal is provided under a long-term contract by MIBRAG's Profen lignite mine.

Saale Energie sells its allocated 400 MW portion of the plant's capacity under a 25-year contract with VEAG, a major German utility that controls the high-voltage transmission of electricity in the former East Germany. VEAG pays a price that is made up of three components, the first of which is designed to recover installation and capital costs, the second to recover operating and other variable costs, and the third to cover fuel supply and transportation costs. We receive 50% of the net profits from these VEAG payments through our ownership interest in Saale Energie.

MIBRAG. We indirectly purchased a 33 1/3% interest in the equity of Mitteldeutsche Braunkohlengesellschaft mbH ("MIBRAG") in 1994 for $10.6 million. MIBRAG owns coal mining, power generation and associated operations, all of which are located south of Leipzig, Germany. MIBRAG was formed by the German government following the reunification of East and West Germany to hold two open-cast brown coal (lignite) mining operations, a lease on an additional mine, three lignite-fired industrial cogeneration facilities and briquette manufacturing and coal dust plants, all located in the former East Germany. MIBRAG's cogeneration operations consist of the 110 MW Mumsdorf facility, the 86 MW Deuben facility and the 37 MW Wahlitz facility. These facilities provide power and thermal energy for MIBRAG's coal mining operations and its briquette manufacturing plants. All power not consumed by MIBRAG's internal operations is sold under an eight-year power purchase agreement with Westsachsische Energie Aktiengesellschaft, a recently privatized German electric utility. MIBRAG's lignite mine

operations include Profen, Zwenkau and Schleenhain with total estimated reserves of 776 million metric tons, which are expected to last for more than 40 years.

A dispute has arisen as to coal transportation compensation payments to be made to MIBRAG pursuant to the acquisition agreement by Bundesanstalt fur vereinigungsbedingte Sonderaufgaben ("BvS"), a German governmental entity that facilitated the privatization of MIBRAG. The size of the annual coal transportation compensation payments fluctuates based on the volume of coal transported to the Schkopau facility. The payment due for 1999 was approximately 50 million deutsche marks (approximately US$25 million) and has been received by MIBRAG. However, BvS disputes its obligation to make any future compensation payments. MIBRAG and BvS are engaged in active discussions to resolve this disagreement. Although MIBRAG believes that a satisfactory resolution can be negotiated, if that did not occur and BvS ceased to make any further annual transportation compensation payments to MIBRAG, but MIBRAG were nevertheless required to continue to transport coal to the Schkopau facility without the benefit of these transportation compensation payments at the prices agreed in 1993 when the compensation and acquisition agreements were negotiated, it would have a material adverse effect on MIBRAG.

Kladno Facilities. The Energy Center Kladno project, located in Kladno, the Czech Republic, consists of two distinct phases. In 1994, we acquired an interest in the existing coal-fired electricity and thermal energy facility that can supply 28 MW of electrical energy and 150 MW equivalent of steam and heated water. This facility historically supplied electrical energy to a nearby industrial complex. The second phase was the expansion of the existing facility, which was completed in January 2000, by the addition of 345 MW of new capacity, 271 MW of which is coal-fired and 74 MW of which is gas-fired. The original project is owned by Energy Center Kladno, a Czech limited liability company in which we own a 44.26% interest. The expansion project is held separately through ECK Generating, a Czech limited liability company in which we own a 44.5% interest.

LATIN AMERICA

We have pursued acquisition and development opportunities in Latin America since the early 1990s. Initially, we participated as one of four original sponsors of a private equity investment fund called Latin Power. More recently, we acquired a 49% interest in the second largest generator of electricity in Bolivia, Compania Boliviana de Energia Electrica S.A.-Bolivian Power Company

Limited ("COBEE"). We plan to selectively target new opportunities in Argentina, Bolivia, Brazil, Chile and Peru, where we believe the more attractive acquisition and greenfield opportunities exist in Latin America.

The following table summarizes our Latin American assets:

NAME AND LOCATION OF FACILITY	PURCHASER/POWER MARKET	TOTAL MW	OUR OWNERSHIP INTEREST	OUR NET OWNERSHIP INTEREST (MW)	FUEL TYPE
COBEE, Bolivia.........................	Electropaz/ELF	219	49.10%	108	Hydro/Gas
Bulo Bulo, Bolivia.....................	Bolivian Grid	87	30.00%	26	Gas
Latin Power Funds, Various............	Various	772	Various	52	Gas/Coal/Oil/Geo
Total...............................		1,078		186	

COBEE. In December 1996, we acquired for $81.8 million a 49% interest in COBEE, the second largest generator of electricity in Bolivia. COBEE has entered into contracts, which expire in 2008, with two Bolivian distribution companies pursuant to which COBEE supplies electricity. All payments under these contracts are made in United States dollars.

COBEE operates its electric generation business under a 40-year concession granted by the Bolivian government in 1990. Under this concession, COBEE is entitled to earn a return of 9.0% on assets within its rate base. The Bolivian Electricity Code also provides for the adjustment of rates to compensate COBEE for any shortfall or to recapture any excess in COBEE's actual rate of return during the previous year. COBEE periodically applies to the Superintendent of Electricity for rate increases sufficient to provide its 9.0% rate of return based on COBEE's current operating results and its projection of future revenues and expenses. Under COBEE's concession, COBEE's assets are required to be removed from the rate base in 2008.

Bulo Bulo Facility. We own a 30% interest in a Bolivian company that will become the owner of the 87 MW gas-fired Bulo Bulo facility located in Carrasco, Bolivia. The Bulo Bulo facility is under construction and is scheduled to enter into commercial operations in mid-May 2000. The Bulo Bulo facility will operate under a 30-year generation license and will sell its power to various customers in Bolivia at market prices established under the rules of the Bolivian national grid.

Latin Power Funds. The original Latin Power Fund was formed in 1993 as a vehicle for making equity investments in independent power projects in Latin America and the Caribbean. We invested $28 million in this original fund and have committed $7 million to a similar fund, both of which are managed by Scudder Kemper Investments. To date, these funds have committed a total of approximately $169 million in investments, of which our share is approximately $28 million.

INTERNATIONAL DEVELOPMENT

In 1999, we and our partners were selected as winning bidder for the 600 MW Seyitomer Power Station and lignite mine in Kuthya, Turkey. Seyitomer is our second successful bid in Turkey. In 1998, also with partners, we won a bid to acquire the 450 MW coal-fired Kangal plant and lignite mine in central Turkey. Our strategy is to build a long-term position in the high-growth energy market in Turkey. In August 1999, the Turkish Parliament amended the Turkish Constitution to allow international arbitration of disputes under concession agreements. The lack of international arbitration for such contracts had been a major stumbling block for many power projects in Turkey, including ours. The Parliament passed additional enabling legislation in January 2000. As a result, our projects, which were delayed pending resolution of this issue, are now proceeding toward financial close, which may occur as early as the end of 2000.

In December 1996, we signed a development and cooperation agreement with representatives of the Estonian Government and the state-owned utility. The development and cooperation agreement defines the terms under which the parties are to establish a plan to develop and refurbish the Balti and Eesti Power Plants. Pursuant to the development and cooperation agreement, we submitted a business plan to the Estonian government in which we have stated our willingness to invest up to $67.25 million of equity into the project and to assist the joint project in obtaining non-recourse debt to fund the required capital improvements to the Balti and Eesti Power Plants, and we are continuing to negotiate a detailed agreement. Because we have a policy of expensing all development costs until there is a signed contract and board of directors' approval, all such costs with respect to this project have been expensed.

We are currently evaluating additional development opportunities in Australia, Turkey, Europe, and Latin America. In Australia, we are specifically evaluating the privatization of South Australian power stations. In Europe, we and our partners are investigating two projects in Poland.

THERMAL ENERGY PRODUCTION AND TRANSMISSION FACILITIES; RESOURCE RECOVERY FACILITIES; LANDFILL GAS FACILITIES

In the United States, our businesses in thermal heating and cooling, landfill gas collection related generation and resource recovery continue to be part of our diversified growth and operating strategies. These businesses give us experience in non-traditional energy sources and in environmentally sound energy alternatives.

NAME AND LOCATION OF FACILITY	ACQUISITION DATE	CAPACITY(1)	OUR OWNERSHIP INTEREST	ENERGY PURCHASER/ MSW SUPPLIER
Thermal Energy Production and Transmission Facilities				
NRG Thermal Corporation				
Minneapolis Energy Center, Minnesota..............	1993	Steam: 1,408 mmBtu/hr. (413 MW) Chilled water: 40,750 tons/hr. (143 MW)	100.00%	Approximately 90 commercial steam customers and 35 commercial chilled water customers
Hennepin Co. Energy Center, Minnesota..............	(2)	290 mmBtu/hr (85 MW)	(2)	Various
San Francisco Thermal, Limited Partnership, California................	1995	Steam; 490 mmBtu/hr. (143 MW)	100.00%	Approximately 185 customers
(Purchased remaining 51%)..	1999			
San Diego Power & Cooling, California................	1997	Chilled Water: 8,000 tons/hr. (28 MW)	100.00%	Approximately 15 customers
Pittsburgh Thermal, Limited Partnership, Pennsylvania.............	1995	Steam; 240 mmBtu/hr. (70 MW)	100.00%	Approximately 25 steam customers and 25 chilled water customers
(Purchased remaining 51%)....................	1999	Chilled Water; 10,180 tons/hr. (36 MW)		
Camas Power Boiler, Washington................	1997	200 mmBtu/hr. (59 MW)	100.00%	Fort James Corp.
Grand Forks Air Force Base, North Dakota..............	1992	105 mmBtu/hr. (31 MW)	100.00%	Grand Forks Air Force Base
Rock-Tenn, Minnesota........	1992	Steam: 430 mmBtu/hr. (126 MW)	100.00%	Rock-Tenn Company
Washco, Minnesota...........	1992	160 mmBtu/hr. (47 MW)	100.00%	Andersen Corporation Minnesota Correctional Facility
Energy Center Kladno, Czech Republic..................	1994	512 mmBtu/hr. (150 MW)	44.26%	City of Kladno
Resource Recovery Facilities				
Newport, Minnesota..........	1993	MSW: 1,500 tons/day	100.00%	Ramsey and Washington Counties
Elk River, Minnesota........	(3)	MSW: 1,500 tons/day	(3)	Anoka, Hennepin, and Sherburne Counties; Tri-County Solid Waste Management Commission
Penobscot Energy Recovery, Maine.....................	1997	MSW: 800 tons/day	28.71%	Bangor Hydroelectric Company
Maine Energy Recovery, Maine.....................	1997	MSW: 680 tons/day	16.25%	Central Maine Power
NEO Corporation............	Various	175 MW	51.72%	Various

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(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. Figures shown above are for 100% of each facility.

(2) We operate this facility on behalf of Hennepin County.

(3) We operate this facility on behalf of Northern States Power.

NRG Thermal Corporation. NRG Thermal Corporation owns the Minneapolis Energy Center and operates the Hennepin County Energy Center. Minneapolis Energy Center provides steam to approximately 90 customers and chilled water to approximately 35 customers in downtown Minneapolis, Minnesota pursuant to energy supply agreements, which expire at varying dates from August 2000 to December 2019. Historically, Minneapolis Energy Center has renewed its energy supply agreements as they near expiration. With minor exceptions, these agreements are standard form contracts providing for a uniform rate structure consisting of three components: a demand charge designed to recover fixed capital costs, a consumption charge designed to provide a per unit margin, and an operating charge designed to pass through to customers all fuel, labor, maintenance, electricity and other operating costs. The demand and consumption charges are adjusted in accordance with the Consumer Price Index every five years.

North American Thermal Systems. We own 100% of North American Thermal Systems LLC, which holds the operating assets of the San Francisco, California and Pittsburgh, Pennsylvania district heating and cooling operations. The San Francisco thermal system has approximately 185 customers. The Pittsburgh thermal system has approximately 25 steam customers and 25 chilled water customers.

Rock-Tenn Facility. The Rock-Tenn process steam operation consists of a five-mile closed-loop steam/condensate line that delivers steam to the Rock-Tenn Company, a paper manufacturer in St. Paul, Minnesota. Rock-Tenn has a peak steam capacity of 430 mmBtus per hour (126 MW equivalent). As a result of the settlement of a 1987 dispute between the Rock-Tenn Company and a previous owner of the steam operation, the Rock-Tenn Company prepaid revenues for future steam service. As of December 31, 1999, deferred revenues remaining were approximately $2.0 million.

NEO Corporation. NEO Corporation is a wholly-owned subsidiary of ours that was formed to develop small power generation facilities, ranging in size from 1 to 50 MW, in the United States. NEO is currently focusing on the development and acquisition of landfill gas projects and the acquisition of small hydroelectric projects. NEO owns 30 landfill gas collection systems and has 55 MW of net ownership interests in related electric generation facilities. As of March 31, 2000, NEO's investment in these projects totaled $73.3 million and loans to fund development, construction and start-up amounted to $28.1 million. NEO also has 35 MW of net ownership interests in 18 small hydroelectric facilities. NEO derives a substantial portion of its income as a result of the generation of Section 29 tax credits, which for 1999 totaled $20.2 million. The existing tax law authorizing these credits is scheduled to expire in 2007.

Resource Recovery Facilities. Our Newport, Minnesota resource recovery facility can process over 1,500 tons of municipal solid waste per day, 90% of which is used as fuel in power generation facilities in Red Wing and Mankato, Minnesota. This facility, which was originally constructed and operated by Northern States Power, was transferred to us in 1993. Pursuant to service agreements with Ramsey and Washington Counties, which expire in 2007, we process a minimum of 280,800 tons of municipal solid waste per year at the Newport facility and receive service fees based on the amount of waste processed, pass-through costs and certain other factors. We are also entitled to an operation and maintenance fee, which is designed to recover fixed costs and to provide us with a guaranteed amount for operating and maintaining the Newport facility for the processing of 750 tons per day of municipal solid waste, whether or not such waste is delivered for processing.

Since 1989, we have operated the Elk River resource recovery facility located in Elk River, Minnesota, which can process over 1,500 tons of municipal solid waste per day, 90% of which is recovered and used in power generation facilities in Elk River and Mankato, Minnesota. Northern States Power owns 85% of the Elk River facility and United Power Association owns the remaining 15%. We also manage and operate an ash storage and disposal facility for the Elk River facility at Northern States Power's Becker ash disposal facility, an approved ash deposit site near Becker, Minnesota. We operate the Becker facility on behalf of Northern States Power.

Resource recovery projects, such as our Newport facility and Northern States Power's Elk River facility, historically were assured an adequate supply of waste through state and local flow control legislation, which directed that waste be disposed of in certain facilities. In 1994, the United States Supreme Court held that such waste was a commodity in interstate commerce and, accordingly, that flow

control legislation that prohibited shipment of waste out of state was unconstitutional. Since this ruling, resource recovery facilities have faced increased competition from landfills in surrounding states in obtaining municipal solid waste; however, this has not materially impacted our municipal solid waste volumes to date.

COMPETITION

The independent power industry is characterized by numerous strong and capable competitors, some of which may have more extensive operating experience, more extensive experience in the acquisition and development of power generation facilities, larger staffs or greater financial resources than we do. Many of our competitors also are seeking attractive power generation opportunities, both in the United States and abroad. This competition may adversely affect our ability to make investments or acquisitions. In recent years, the independent power industry has been characterized by increased competition for asset purchases and development opportunities.

In addition, regulatory changes have also been proposed to increase access to transmission grids by utility and non-utility purchasers and sellers of electricity. The Energy Policy Act laid the ground work for a competitive wholesale market for electricity. Among other things, the Energy Policy Act expanded FERC's authority to order wholesale transmission, thus allowing QFs, power marketers and EWGs to compete more effectively in the wholesale market. In May 1996, FERC issued the first of the Open Access Rules, which requires utilities to offer eligible wholesale transmission customers non-discriminatory open access on utility transmission lines on a comparable basis to the utilities' own use of the lines. In addition, the Open Access Rules direct the regional power pools that control the major electric transmission networks to file uniform, non-discriminatory open access tariffs. The Open Access Rules have been the subject of rehearing at FERC and are now undergoing judicial review. Over the past few years, Congress and the administration of President Clinton have considered various pieces of legislation to restructure the electric industry that would require, among other things, customer choice or repeal of PUHCA. The debate is likely to continue and perhaps intensify. The effect of enacting such legislation cannot be predicted with any degree of certainty. Industry deregulation may encourage the disaggregation of vertically integrated utilities into separate generation, transmission and distribution businesses. As a result of these potential regulatory changes, significant additional competitors could become active in the generation segment of our industry.

FINANCING

We fund our projects with a combination of non-recourse debt and equity contributions. Historically, equity contributions infused into a project consisted of cash from operations, corporate-level debt and capital contributions from Northern States Power.

NON-RECOURSE FINANCING

As with our existing facilities, we expect to finance most of our future projects with debt as well as equity. Leveraged financing permits the development of projects with a limited equity base, but also increases the risk that a reduction in revenues could adversely affect a particular project's ability to meet its debt or lease obligations.

We have financed our principal power generation facilities primarily with non-recourse debt that is repaid solely from the project's revenues and generally is secured by the physical assets, major project contracts and agreements, cash accounts and, in certain cases, our ownership interest, in that project affiliate. This type of financing is referred to as "project financing." True project financing is not available for all projects, including some assets purchased out of bankruptcy, some merchant plants, some purchases of minority stock positions in publicly traded companies and plants in certain countries that lack a sufficiently well-developed legal system. Even in those instances, however, we may still be able to finance a smaller portion of the total project cost with project financing, with the remainder financed with debt that is either raised or supported at the corporate rather than the project level.

Project financing transactions generally are structured so that all revenues of a project are deposited directly with a bank or other financial institution acting as escrow or security deposit agent. These funds then are payable in a specified order of priority set forth in the financing documents to ensure that, to the extent available, they are used first to pay operating expenses, senior debt service and taxes and to fund reserve accounts. Thereafter, subject to satisfying debt service coverage ratios and certain other conditions, available funds may be disbursed for management fees or dividends or, where there are subordinated lenders, to the payment of subordinated debt service.

In the event of a foreclosure after a default, our project affiliate owning the facility would only retain an interest in the assets, if any, remaining after all debts and obligations were paid. In addition, the debt of each operating project may reduce the liquidity of our equity interest in that project because the interest is typically subject both to a pledge securing the project's debt and to transfer restrictions set forth in the relevant financing agreements. Also, our ability to transfer or sell our interest in certain projects is restricted by certain purchase options or rights of first refusal in favor of our partners or the project's power and steam purchasers and certain change of control restrictions in the project financing documents.

These project financing structures are designed to prevent the lenders from looking to us or our other projects for repayment; that is, they are "non-recourse" to us and our other project affiliates not involved in the project, unless we or another project affiliate expressly agree to undertake liability. We have agreed to undertake limited financial support for certain of our project affiliates in the form of certain limited obligations and contingent liabilities. These obligations and contingent liabilities take the form of guarantees of certain specified obligations, indemnities, capital infusions and agreements to pay certain debt service deficiencies. To the extent we become liable under such guarantees and other agreements in respect of a particular project, distributions received by us from other projects may be used by us to satisfy these obligations. To the extent of these obligations, creditors of a project financing may have recourse to us. See "Risk Factors -- We have guaranteed obligations and liabilities of our project subsidiaries and affiliates which would be difficult for us to satisfy if they all came due simultaneously."

RECOURSE FINANCING

Recourse financing through corporate-level debt is provided in many different forms. For instance, we have issued corporate-level debt and we periodically provide corporate-level guarantees to various subsidiary financings, mainly as an alternative to funding debt service reserve accounts with project cash. Our goal is to have a recourse debt to recourse debt and equity capitalization ratio of 40-50%. Our credit ratings are "Baa3" on review for possible upgrade from Moody's Investors Service, Inc. and "BBB-" stable from Standard & Poor's Ratings Services.

EXPOSURE TO CURRENCY FLUCTUATION

We seek to manage our exposure to changes in currency exchange rates by matching the currency of revenues with the currency of expenses for each project to create a natural hedge against fluctuations in the currency markets. At the project level we typically sell power, buy fuel, and issue debt in the functional currency of the project. At the corporate level, when a significant source of operating cash is derived from a foreign investment, a portion of corporate debt may be issued in that currency. A recent example of this was our issuance in March 2000 of L160 million 7.97% Senior Reset Notes as a partial hedge of our purchase of the Killingholme project in the United Kingdom.

After matching the currency of revenues and expenses, the remaining foreign currency risk is hedged under the guidelines set forth in our foreign exchange risk management policy. This policy requires us to hedge, when possible, all known and highly probable cash flows over a twelve to eighteen month horizon through the use of forward, swap and option contracts with highly rated financial institutions as appropriate. We do not speculate on changes in foreign exchange rates.

As part of our strategy, we hold assets and liabilities denominated in foreign currencies. We adjust the value of these holdings quarterly to reflect fluctuations in the values of their respective currencies. This can, and has, generated non-cash income and losses.

REGULATION

We are subject to a broad range of federal, state and local energy and environmental laws and regulations applicable to the development, ownership and operation of our United States and international projects. These laws and regulations generally require that a wide variety of permits and other approvals be obtained before construction or operation of a power plant commences and that, after completion, the facility operate in compliance with their requirements. We strive to comply with the terms of all such laws, regulations, permits and licenses and believe that all of our operating plants are in material compliance with all such applicable requirements. We cannot assure you, however, that in the future we will obtain all necessary permits and approvals and that we will comply with all applicable statutes and regulations. In addition, regulatory compliance for the construction of new facilities is a costly and time-consuming process, and intricate and rapidly changing environmental regulations may require major expenditures for permitting and create the risk of expensive delays or material impairment of project value if projects cannot function as planned due to changing regulatory requirements or local opposition. Furthermore, we cannot assure you that existing regulations will not be revised or that new regulations will not be adopted or become applicable to us which could have an adverse impact on our operations.

In particular, the independent power markets in the United States, United Kingdom, Australia and other countries are dependent on the existing regulatory structure, and while we strive to take advantage of the opportunities created by regulatory changes, it is impossible to predict the impact of regulatory changes on our operations. Further, we believe that the level of environmental awareness and enforcement is growing in most countries, including most of the countries in which we intend to develop and operate new projects. Therefore, based on current trends, we believe that the nature and level of environmental regulation to which we are subject will become increasingly stringent. Our policy is therefore to operate our projects in accordance with applicable local law or relevant environmental guidelines adopted by the World Bank, whichever reflects the more stringent level of control.

ENERGY REGULATION -- UNITED STATES

Federal Power Act. The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction are required to file rate schedules with FERC prior to commencement of wholesale sales or interstate transmission of electricity. Public utilities with cost-based rate schedules are also subject to accounting, record-keeping and reporting requirements administered by FERC.

PURPA and the Energy Policy Act. The enactment of PURPA in 1978 provided incentives for the development of Qualifying Facilities or "QFs", which were basically cogeneration facilities and small power production facilities that utilized certain alternative or renewable fuels. QF status conveys two primary benefits. First, regulations under PURPA exempt Qualifying Facilities from PUHCA, most provisions of the Federal Power Act and the state laws concerning rates, and financial and organizational regulations of electric utilities. Second, FERC's regulations under PURPA require that (1) electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's full avoided cost of producing power, (2) the electric utilities must sell back-up, interruptible, maintenance and supplemental power to the QF on a non-discriminatory basis, and (3) the electric utilities must interconnect with any QF in its service territory, and, if required, transmit power if they do not purchase it. We endeavor to acquire, develop and operate our QFs in a manner that minimizes the risk of those plants losing their QF status. However, if a facility were to lose QF status, we could attempt to avoid regulation under PUHCA by qualifying the project as an EWG. The passage of the Energy Policy Act in 1992 further encouraged independent power production by providing certain exemptions from regulation for EWGs and FUCOs.

All of our subsidiaries that would otherwise be treated as public utilities are currently QFs, EWGs or FUCOs. An EWG is an entity that is exclusively engaged, directly or indirectly, in the business of owning or operating facilities that are exclusively engaged in generation and selling electric energy at wholesale.

An EWG will not be regulated under PUHCA, but is subject to FERC and state public utility commission regulatory reviews, including rate approval. EWGs do not enjoy the same statutory and regulatory exemptions from state regulation as are granted to QFs. In fact, however, since EWGs are only allowed to sell power at wholesale, their rates must receive initial approval from FERC rather than the states. All of our EWGs to date that have sought rate approval from FERC have been granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates. However, FERC customarily reserves the right to suspend, upon complaint, market-based rate authority on a prospective basis if it is subsequently determined that we or any of our EWGs exercised market power. If FERC were to suspend market-based rate authority, it would most likely be necessary to file, and obtain FERC acceptance of, cost-based rate schedules for any of our EWGs. Also, the loss of market-based rate authority would subject the EWGs to the accounting, record-keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules.

In addition, if there occurs a "material change" in facts that might affect any of our subsidiaries' eligibility for EWG status, within 60 days of the material change, the relevant EWG must (i) file a written explanation of why the material change does not affect its EWG status, (ii) file a new application for EWG status, or (iii) notify FERC that it no longer wishes to maintain EWG status. If any of our subsidiaries were to lose EWG status, we, along with our affiliates, would be subject to regulation under PUHCA as a public utility company. Absent a substantial restructuring of our business, it would be difficult for us to comply with PUHCA without a material adverse effect on our business.

FUCOs are companies owning or operating PUHCA jurisdictional facilities not located in the United States that derive no part of their income directly or indirectly from United States public utility activities. FUCOs are exempted from all provisions of PUHCA.

After the merger of Northern States Power and New Century Energies, our shares of class A common stock will be owned by the surviving entity, Xcel Energy. Xcel Energy will be subject to the provisions of various energy-related laws and regulations, including regulation as a registered holding company under PUHCA, and, in turn, we will be subject to regulations imposed by PUHCA. These regulations include restrictions imposed upon aggregate investment by registered holding companies in EWGs and FUCOs that are financed by contributions or guarantees by the parent holding company. These investment restrictions, issued pursuant to SEC regulations, limit registered holding company investment in EWGs/FUCOs without prior SEC approval to 50% of the registered holding company's consolidated retained earnings. The SEC has increased this "safe harbor" investment cap to 100% of retained earnings for a number of registered holding companies, and Xcel Energy has a pending request to raise its EWG/ FUCO investment threshold to 100%.

The existence of this investment cap and the potential need to request SEC waivers of or increases in the cap could delay or prevent any infusions of capital from Xcel Energy that it may desire to make. This delay could be increased by the fact that to obtain a waiver from the SEC typically would require Xcel Energy to provide letters in support of such waiver from each state public service commission which regulates Xcel Energy's utility business, which could be time consuming and subject the waiver request to delays due to other matters in dispute between Xcel Energy and any one of the 12 public service commissions that are expected to regulate its utility business.

Another constraint is that we could be delayed in creating subsidiaries that would not be involved in energy-related activities. We have created such subsidiaries in the past to enable certain of our project subsidiaries to acquire the status of an EWG, so any delay in this process could delay closings on future transactions, which could in turn have an adverse impact on us.

Finally, transactions among us and our associate companies within the Xcel system (including Xcel Energy) would need to be "at cost" unless they fit within specified regulatory exceptions or were approved by the SEC. This constraint could delay our execution of contracts between our subsidiaries and other companies within the Xcel system, or limit terms to be contained in these contracts, which could have an adverse impact on us.

State Energy Regulation. In areas outside of wholesale rate regulation (such as financial or organizational regulation), some state utility laws may give their public utility commissions broad jurisdiction over steam sales or EWGs that sell power in their service territories. The actual scope of that jurisdiction over steam or independent power projects varies significantly from state to state, depending on the law of that state.

ENVIRONMENTAL REGULATION -- UNITED STATES

The construction and operation of power projects are subject to extensive environmental protection and land use regulation in the United States. These laws and regulations often require a lengthy and complex process of obtaining licenses, permits and approvals from federal, state and local agencies. If such laws and regulations are changed and our facilities are not grandfathered, extensive modifications to project technologies and facilities could be required.

General. Based on current trends, we expect that environmental and land use regulation will continue to be stringent. Accordingly, we plan to carefully monitor and provide input on critical legislative initiatives that could impact the operation of our facilities and to actively review proposed construction projects that could subject us to stringent pollution controls imposed on "major modifications" as defined under the Clean Air Act and changes in discharge characteristics as defined under the Clean Water Act. The goal of these actions will be to achieve compliance with applicable regulations, administrative consent orders, and variances from applicable air-quality related regulations.

Clean Air Act. Most of our steam electric generating plants in the United States are subject to Title IV of the Clean Air Act, which requires certain fossil-fuel-fired combustion devices to hold sulphur dioxide "allowances" for each ton of sulphur dioxide emitted. We plan to comply with the need for holding the appropriate number of allowances by reducing sulphur dioxide emissions through use of low sulphur fuels, installation of "back end" control technology, and purchase of allowances on the open market. The costs of obtaining the required number of allowances needed for future projects will be integrated into our overall financial analysis of such projects.

Our plants are subject to a variety of regulations governing emissions of nitrogen oxides ("NO(X)"). At the Encina facility, we anticipate installing selective catalytic reduction devices on at least two of the units in the next several years in order to meet mandated pollution control requirements.

In addition to the above, our plants in the Northeast region are required to hold NO(X) emissions allowances that equal, for each period from May 1 to September 30, our NO(X) emissions from all of our facilities subject to the program. Our facilities in El Segundo and Long Beach are subject to another emissions trading program designed to control NO(X). We currently intend to install selective catalytic reduction devices on one of the units at the El Segundo facility in order to assist with our compliance with this program. As for our facilities in the Northeast we intend to implement a strategic plan for the purchase of NO(X) allowances and the reduction of NO(X) emissions through the installation of pollution control equipment as appropriate.

Title V of the Clean Air Act imposes federal requirements which dictate that most of our fossil fuel-fired generation facilities must obtain operating permits. All of our existing facilities subject to this requirement have submitted timely Title V permit applications. However, most facilities have not yet received final Title V permits. We do not anticipate that the costs of obtaining final operating permits will be material.

In 1997, we were issued Administrative Orders and Notices of Civil Administrative Penalty Assessments by the New Jersey Department of Environmental Protection as a result of the operations of two cogeneration facilities that we operated. The Administrative Orders and Notices of Civil Administrative Penalty Assessments resulted from alleged air emissions in excess of permit limits that occurred prior to our acquisition of these cogeneration facilities. Notwithstanding this fact, we agreed to settle the outstanding administrative orders with the New Jersey Department of Environmental Protection

and executed an administrative consent order with the New Jersey Department of Environmental Protection in March 2000, pursuant to which we paid a penalty in the amount of $102,500.

As a result of alleged violations of visible emissions standards at the Huntley, Dunkirk and Oswego facilities, the previous owner of these facilities was in the process of negotiating a consent order with the New York Department of Environmental Conservation to resolve such violations at the time we acquired these facilities. Under the terms of our purchase agreements with the previous owner, it will be responsible for any fines, penalties, assessments and related losses resulting from its failure to comply with environmental laws and regulations. We have agreed, in connection with our acquisition of these facilities, to enter into separate consent orders for each of these facilities to address on-going and potential future violations of visible emissions standards. We believe that a majority of all of the visible emissions violations at the Huntley, Dunkirk and Oswego facilities are non-preventable events occurring as a result of startups and shutdowns at those facilities that should not be subject to penalties under the New York regulations. We are currently in discussions with the New York Department of Environmental Conservation regarding this issue.

On October 14, 1999, Governor Pataki of New York announced that he was ordering the New York Department of Environmental Conservation to require further reductions of sulphur dioxide and nitrogen oxides emissions from New York power plants, beyond that which is required under current federal and state law. These reductions would be phased in between January 1, 2003 and January 1, 2007. Compliance with these emissions reductions requirements, if they become effective, could have a material adverse impact on the operation of some of our facilities located in the State of New York.

On May 17, 2000, Governor Rowland of Connecticut issued an Executive Order to the CDEP that requires the CDEP to develop regulations, applicable to power plants and other major sources of air pollution, to further reduce emissions of nitrogen oxides and sulphur dioxides by May 2003. The Executive Order requires reductions of sulphur dioxides by an amount that is 30 to 50% greater than current commitments and reductions of nitrogen oxides that are 20 to 30% greater than current commitments. The Executive Order provides that the CDEP should use market based incentives and a system of creditable emissions allowances or credits to foster cost effective reductions. In addition, the Connecticut legislature has in the past considered, but rejected, legislation that would require older electrical generation stations to comply with more stringent pollution standards than are currently in effect in Connecticut for nitrogen oxides and sulphur dioxide emissions. The legislation debated during the 2000 legislative session would have required our Connecticut facilities to rely on more expensive fuels or install additional pollution control equipment. If such legislation were to become law without reflecting the benefit of critical elements of current federal emission reduction initiatives (e.g. market based emissions trading between sources located across broad geographical regions), our Connecticut facilities may be placed at a significant competitive disadvantage.

The New York Department of Environmental Conservation recently issued a Notice of Violation to us and the prior owner of our Huntley and Dunkirk facilities relating to physical changes made at the Huntley and Dunkirk facilities prior to our assumption of ownership. The Notice of Violation alleges that such changes represent major modifications undertaken without obtaining the required permits. If these facilities did not comply with the applicable permit programs, we could be required, among other things, to install best available control technology to further reduce criteria pollutant emissions from the Dunkirk and Huntley facilities, and we could become subject to fines and penalties associated with the period of time we have operated the facilities.

In addition, on November 3, 1999, the United States Department of Justice filed suit against seven electric utilities for alleged violations of Clean Air Act requirements related to modifications of existing sources at seventeen utility generation stations located in the southern and midwestern regions of the United States. The EPA also issued administrative notices of violation alleging similar violations at eight other power plants owned by some of the electric utilities named as defendants in the lawsuit, and also issued an administrative order to the Tennessee Valley Authority for similar violations at seven of its power plants. To date, no lawsuits or administrative actions have been brought against us or any of our subsidiaries or affiliates or the former owners of our facilities alleging similar violations, although Atlantic City Electric Company, a subsidiary of Conectiv, has received information requests from the EPA regarding the Deepwater and BL England facilities that we have agreed to purchase. Lawsuits or administrative actions alleging similar violations at our facilities could be filed in the future and, if successful, could have a material adverse effect on our business.

Clean Water Act. Our existing facilities are also subject to a variety of state and federal regulations governing existing and potential water/wastewater discharges therefrom. Generally, such regulations are promulgated under authority of the Clean Water Act and govern overall water/wastewater discharges, through National Pollutant Discharge Elimination System ("NPDES") permits. Under current provisions of the Clean Water Act, existing NPDES permits must be renewed every five years, at which time permit limits are extensively reviewed and can be modified to account for changes in regulations or program initiatives. In addition, the permits have re-opener clauses which the federal government can use to modify a permit at any time. Many of our existing facilities have been operating under NPDES permits for a long time and have gone through one or more NPDES permit renewal cycles and are currently in the process of renewing their existing NPDES permits again. In addition, some facilities are now lawfully operating under terms of an existing consent order.

We cannot assure you that existing laws and regulations will not be revised or that new regulations will not be adopted or become applicable to us which could have an adverse impact on our operations.

Site Remediation. Environmental site assessments have been prepared for all of our recently acquired Northeast assets. The remediation activities at the Arthur Kill facility, Astoria Gas Turbines and Somerset facility are still in the study phase. As such, the remediation cost estimates are based on approaches that have not been approved yet by the regulatory agencies involved.

For our Connecticut facilities, we are planning to conduct additional studies to better quantify remedial need. Such studies include the preparation of risk assessments to justify remedial actions proposed by us to the Connecticut Department of Environmental Protection and the EPA.

ENERGY REGULATION -- INTERNATIONAL

Most of the foreign countries in which we own or may acquire or develop independent power projects have laws or regulations relating to the ownership or operation of electric power generation facilities. These laws and regulations are typically significant for independent power producers because they are still changing and evolving in many countries. Although the type and nature of these energy or electric laws vary widely from country to country, many of them address some or all of the following issues:

- Establishment of an energy regulatory body;

- Financial or technical qualifications for independent power producers;

- Licensing requirements and procedures for independent power projects or producers;

- Procedures for deciding whether the construction of new power plants should be allowed;

- Procedures for selling or transferring existing generating facilities to third parties;

- Price regulations; or

- Incentives for independent power developers or developers of new power facilities.

We retain appropriate advisors in foreign countries and seek to design our international development and acquisition strategy to comply with and take advantage of opportunities presented by each country's energy laws and regulations. There can be no assurance, however, that changes in such laws or regulations could not adversely affect our international operations.

ENVIRONMENTAL REGULATIONS -- INTERNATIONAL

Although the type of environmental laws and regulations applicable to independent power producers and developers varies widely from country to country, many foreign countries have laws and regulations relating to the protection of the environment and land use which are similar to those found in the United States. Laws applicable to the construction and operation of electric power generation facilities in foreign countries generally regulate discharges and emissions into water and air, and also regulate noise levels. Air pollution laws in foreign jurisdictions often limit the emissions of particles, dust, smoke, carbon monoxide, sulfur dioxide, nitrogen oxides and other pollutants. Water pollution laws in foreign countries generally limit wastewater discharges into municipal sewer systems and require treatment of wastewater so that it meets established standards. New projects and modifications to existing projects are also subject, in many cases, to land use and zoning restrictions imposed in the foreign country. In addition to the requirements currently imposed by a particular country, most lenders to international development projects may impose their own requirements relating to protection of the environment.

We believe that the level of environmental awareness and enforcement is growing in most countries, including most of the countries in which we intend to develop and operate new projects. Accordingly, based on current trends, we believe that the nature and level of environmental regulation to which we are subject will become increasingly stringent. Therefore, our policy is to operate our projects in accordance with environmental guidelines adopted by the World Bank or applicable local law, whichever reflects the more stringent level of control.

OTHER PROPERTIES

In addition to the other properties discussed in this prospectus, we lease approximately 60,000 square feet of office space at 1221 Nicollet Mall, Suite 700, Minneapolis, Minnesota 55403, under a five-year lease that expires in June 2002. We will be relocating our offices in the near future to approximately 100,000 square feet of office space in Minneapolis, Minnesota as to which we have recently entered into a 10 year lease.

We also own interests in the following power generation facilities that have been idled: Madera, Chowchilla II and El Nido, San Joaquin Valley, California; Jackson Valley Energy Partners, Ione, California; Artesia, California; and Turners Falls, Massachusetts, which facilities represent an aggregate equity generation capacity of 63 MW and a book value of $8.4 million.

EMPLOYEES

At December 31, 1999, we had 1,809 employees, approximately 400 of whom are employed directly by us and approximately 1,409 of whom are employed by our wholly-owned subsidiaries.

The majority of our domestic and international projects employ unionized employees whose conditions of employment are covered by collective bargaining agreements. We have experienced no significant labor stoppages or labor disputes at our facilities.

LEGAL PROCEEDINGS

On or about July 12, 1999, Fortistar Capital Inc., a Delaware Corporation, filed a complaint in the Fourth Judicial District, Hennepin County, Minnesota against us, asserting claims for injunctive relief and for damages as a result of our alleged breach of a confidentiality letter agreement with Fortistar relating to the Oswego facility. We disputed Fortistar's allegations and have asserted numerous counterclaims. We have counterclaimed against Fortistar for breach of contract, fraud and negligent misrepresentations and omissions, tortuous interference with contract, prospective business opportunities and prospective contractual relationships, unfair competition and breach of covenant of good faith and fair dealing. We seek, among other things, dismissal of Fortistar's complaint with prejudice and rescission of the letter agreement.

A temporary injunction hearing was held on September 27, 1999. The acquisition of the Oswego facility was closed on October 22, 1999, following notification to the court of our and Niagara Mohawk's intention to close on that date. On January 14, 2000, the court denied Fortistar's request for a temporary injunction. We intend to continue to vigorously defend the suit and believe Fortistar's complaint to be without merit. No trial date has been set.

On October 12, 1999, we received a letter from the Office of the Attorney General of the State of New York alleging that based on a preliminary analysis, it believes that major modifications were made to our Huntley and Dunkirk facilities during prior ownership of those facilities without the required permits having been obtained. On May 25, 2000, we and the previous owner of our Huntley and Dunkirk facilities received a Notice of Violation from the

Department of Environmental Conservation of the State of New York regarding these allegations. We believe that the Department of Environmental Conservation sent similar Notices of Violation to the owners and operators of many of the coal-fired utility plants in New York. The Notice of Violation states that the Department of Environmental Conservation is reviewing its options regarding appropriate enforcement actions, including assessment of penalties, fines and injunctive relief. While we do not have knowledge at this time that the previous owner of the Huntley and Dunkirk facilities did not comply with the preconstruction permit requirement, we cannot predict the outcome of any such enforcement actions, as we have only owned these facilities since June 1999. Although we have a right to indemnification by the previous owner for penalties resulting from the previous owner's failure to comply with environmental laws and regulations, if these facilities did not comply with the applicable permit requirements, we could be required, among other things, to install specified pollution control technology to further reduce pollutant emissions from the Dunkirk and Huntley facilities, and we could become subject to fines and penalties associated with the period of time we have operated the facilities.

The independent system operator for the New York Power Pool has recently imposed price limitations on certain ancillary services sold in this market, and, together with several New York utilities, has sought authority from FERC to adjust the market-clearing prices for 10-minute reserve services on a retroactive basis. We have joined several other independent power producers in New York in filing a claim with FERC challenging these actions. If the independent system operator prevails, our revenues from ancillary services sold in the New York Power Pool could be substantially reduced. Although we would attempt to adjust our business operations to mitigate the future impact of such a ruling, the potential negative

impact on our revenues for the first quarter of 2000 would include the potential refund of approximately $8.0 million of revenues collected in February 2000 and the inability to collect approximately $8.2 million included in revenues, but not yet collected, for March 2000.

There are no other material legal proceedings pending, other than ordinary routine litigation incidental to our business, to which we are a party. There are no material legal proceedings to which an officer or director is a party or has a material interest adverse to us or our subsidiaries. There are no material administrative or judicial proceedings arising under environmental quality or civil rights statutes pending or known to be contemplated by governmental agencies to which we are or would be a party.

MANAGEMENT

The name, age and title of each of the directors and executive officers of NRG as of March 31, 2000 are as set forth below:

NAME	AGE	TITLE
David H. Peterson	58	Chairman of the Board, President, Chief Executive Officer and Director
Gary R. Johnson	53	Director
Cynthia L. Lesher	51	Director
Edward J. McIntyre	49	Director
Leonard A. Bluhm	54	Executive Vice President and Chief Financial Officer
Keith G. Hilless	61	Senior Vice President, Asia Pacific
Craig A. Mataczynski	39	Senior Vice President, North America
John A. Noer	53	Senior Vice President
Ronald J. Will	59	Senior Vice President, Europe
James J. Bender	43	Vice President, General Counsel and Corporate Secretary
Brian B. Bird	37	Vice President and Treasurer

Roy R. Hewitt........................	54	Vice President, Administrative Services
Valorie A. Knudsen...................	43	Vice President, Corporate Strategy and Portfolio Assessment
Louis P. Matis.......................	49	Vice President, Corporate Operating Services
David E. Ripka.......................	51	Vice President and Controller

David H. Peterson has been Chairman of the Board of NRG since January 1994, Chief Executive Officer since November 1993, President since 1989 and a Director since 1989. Mr. Peterson was also Chief Operating Officer of NRG from June 1992 to November 1993. Prior to joining NRG, Mr. Peterson was Vice President, Non-Regulated Generation for Northern States Power, and he has served in various other management positions with Northern States Power during the last 20 years. Mr. Peterson has also been a director of Northern States Power subsidiary Energy Masters International, Inc. since November 1993.

Gary R. Johnson has been a Director of NRG since 1993 and Vice President and General Counsel of Northern States Power since November 1991. Prior to November 1991, Mr. Johnson was Vice President-Law of Northern States Power from January 1989, acting Vice President from September 1988 and Director of Law from February 1987, and he has served in various management positions with Northern States Power during the last 20 years. Mr. Johnson has also been a director of Northern States Power's subsidiaries Seren Innovations, Inc. since November 1996 and Viking Gas Transmission Company since March 1997.

Cynthia L. Lesher has been a Director of NRG since June 1996 and became President of Northern States Power-Gas in July 1997. Prior to July 1997, Ms. Lesher was Vice President-Human Resources of Northern States Power since March 1992 after serving as Director of Power Supply-Human Resources since 1991. Ms. Lesher became Area Manager, Electric Utility Operations, in 1990, and previously served as Manager, Metro Credit, and Manager, Occupational Health and Safety. Prior to joining Northern States Power, Ms. Lesher was a training and development consultant at the Center for Continuing Education in Minneapolis. From 1970 to 1977, she held a variety of positions with Multi Resource Centers, Inc., also in Minneapolis. Ms. Lesher has also been a director and Chairperson of Northern States Power subsidiaries Black Mountain Gas Company since July 1999, Natrogas, Incorporated since December 1999 and Viking Gas Transmission Company since July 1997, where she has served as Chairperson since June 1998.

Edward J. McIntyre has been a Director of NRG since 1993 and Vice President and Chief Financial Officer of Northern States Power since January 1993. Mr. McIntyre has also been a director of Northern States Power subsidiaries Eloigne Company since April 1993 and Energy Masters International, Inc. since September 1994. Mr. McIntyre served as President and Chief Executive Officer of Northern States Power-Wisconsin, a wholly-owned subsidiary of Northern States Power, from July 1990 to December 1992, as

Vice President Gas Utility from November 1985 to June 1990, and he has served in various other management positions since joining Northern States Power in 1973.

Leonard A. Bluhm has been Executive Vice President and Chief Financial Officer of NRG since January 1997. Immediately prior to that, he served as the first President and Chief Executive Officer of Cogeneration Corporation of America. Mr. Bluhm was Vice President, Finance of NRG from January 1993 through April 1996. Mr. Bluhm was Chief Financial Officer of Cypress Energy Partners, a wholly-owned project subsidiary of NRG, from April 1992 to January 1993, prior to which he was Director, International Operations and Manager, Acquisitions and Special Projects of NRG from 1991. Mr. Bluhm previously served for 20 years in various financial positions with Northern States Power.

Keith G. Hilless has been Senior Vice President, Asia Pacific of NRG and Managing Director of NRG Asia Pacific since July 1998, prior to which he was a senior executive since August 1997. Prior to joining NRG, Mr. Hilless was Chief Executive Officer of the Queensland Transmission and Supply Corporation where he had served since January 1995. From 1993 to January 1995, Mr. Hilless served as the Queensland Electricity Commissioner.

Craig A. Mataczynski has been Senior Vice President, North America of NRG and President and Chief Executive Officer of NRG North America, since July 1998. From December 1994 until July 1998, Mr. Mataczynski served as Vice President, U.S. Business Development of NRG. From May 1993 to January 1995, Mr. Mataczynski served as President of NEO Corporation, NRG's wholly-owned subsidiary that develops small electric generation projects within the United States. Prior to joining NRG, Mr. Mataczynski worked for Northern States Power from 1982 to 1994 in various positions, including Director, Strategy and Business Development and Director, Power Supply Finance.

John A. Noer has been Senior Vice President of NRG and President of NRG Worldwide Operations since January 1, 2000. Immediately prior to that he served as President-NSP Combustion and Hydro Generation for Northern States Power Company and as a director of NRG since June 1997. He was President and CEO of Northern States Power Wisconsin, a wholly-owned subsidiary of Northern States Power, since January 1993. Prior to joining Northern States Power Wisconsin, Mr. Noer was President of Cypress Energy Partners, a project subsidiary of NRG, from March 1992 to January 1993. Prior to joining Cypress Energy Partners, Mr. Noer held various management positions with Northern States Power since joining the company in September 1968.

Ronald J. Will has been Senior Vice President, Europe of NRG and President and Chief Executive Officer of NRG Europe since July 1998. From March 1994 until July 1998, Mr. Will served as Vice President, Operations and Engineering of NRG, prior to which he served as Vice President, Operations from June 1992. Prior to joining NRG, he served as President and Chief Executive Officer of NRG Thermal from February 1991 to June 1993. Prior to February 1991, Mr. Will served in a variety of positions with Norenco, a wholly-owned thermal services subsidiary of NRG, including Vice President and General Manager from August 1989 to February 1991.

James J. Bender has been Vice President, General Counsel and Secretary of NRG since June 1997. He served as the General Counsel of the Polymers Division of Allied Signal Inc. from May 1996 until June 1997. From June 1994 to May 1996, Mr. Bender was employed at NRG, acting as Senior Counsel until December 1994 and as Assistant General Counsel and Corporate Secretary from December 1994 to May 1996.

Brian B. Bird has been Vice President and Treasurer of NRG since June 1999 and Treasurer since June 1997, prior to which he was Director of Corporate Finance and Treasury for Deluxe Corporation in Shoreview, Minnesota from September 1994 to May 1997. Mr. Bird was Manager of Finance for the Minnesota Vikings professional football team from March 1993 to September 1994. Mr. Bird held several financial management positions with Northwest Airlines in Minneapolis, Minnesota from 1988 to March 1993.

Roy R. Hewitt has been Vice President, Administrative Services at NRG since February 1999. He has nearly 30 years experience in the power industry including 24 years with Northern States Power and

six years with NRG. Mr. Hewitt joined NRG in 1994 as a member of the senior management team with NRG's Gladstone Power Station project in Queensland, Australia. In 1996, he returned to NRG's corporate headquarters as Executive Director, Human Resources. In 1997, Mr. Hewitt returned to Australia as Managing Director of the Gladstone Project and later served as Executive Director, Operations and Engineering for NRG's Asia-Pacific region headquartered in Brisbane, Australia.

Valorie A. Knudsen has been Vice President, Corporate Strategy and Portfolio Assessment since February 2000. She has served as Vice President, Emerging Markets; Vice President, Finance and as Controller since joining NRG in August 1993. Prior to joining NRG, Ms. Knudsen served in various managerial accounting positions from November 1987 to July 1993 with Carlson Companies, Inc. Before joining Carlson Companies, Ms. Knudsen practiced as a Certified Public Accountant for seven years.

Louis P. Matis has been Vice President, Corporate Operating Services of NRG since July 1998, prior to which he served in a variety of roles at Northern

States Power. Mr. Matis joined Northern States Power in 1983 as a civil engineer and managed the construction and engineering of numerous projects. In 1990 he joined Fuel Resources as Manager and then Director, managing a portfolio of nuclear fuel, fossil fuel and transportation contracts as well as a nuclear fuel design group for Northern States Power. In 1996, he became General Manager of fossil fuel plants for Northern States Power. Upon closing of the pending merger between Northern States Power and New Century Energies, Mr. Matis will become an employee of Xcel Energy.

David E. Ripka has been Vice President and Controller of NRG since June 1999, and Controller since March 1997. Prior to joining NRG, Mr. Ripka held a variety of positions with Northern States Power for over 20 years, including Assistant Controller and General Manager of Accounting Operations and Director of Audit Services. Upon closing of the pending merger between Northern States Power and New Century Energies, Mr. Ripka will become an employee of Xcel Energy.

BOARD OF DIRECTORS

Upon completion of this offering, our board of directors will consist of six directors: Mr. Peterson and five employees of Northern States Power or New Century Energies. We anticipate that shortly after the completion of this offering, our board of directors will be expanded to consist of nine members. We have agreed with the NYSE that we will appoint two independent directors within 90 days of the completion of this offering and a third independent director not later than one year after the completion of this offering.

COMMITTEES OF THE BOARD OF DIRECTORS

Our board of directors will have a compensation committee and an audit committee.

Compensation Committee. The compensation committee will consist of at least two of the independent directors to be appointed after this offering. The compensation committee will review and make recommendations to our board of directors concerning salaries and incentive compensation for our officers and employees. The compensation committee also will administer the NRG 2000 Long-Term Incentive Compensation Plan.

Audit Committee. The audit committee will consist entirely of independent directors who are "financially literate," and possess "accounting or related financial management expertise" as required under applicable regulations. The audit committee will review and monitor our financial statements and accounting practices, make recommendations to our board of directors regarding the selection of independent auditors and review the results and scope of the audit and other services provided by our independent auditors.

COMPENSATION OF DIRECTORS

Directors who are also employees of NRG or Northern States Power do not receive any compensation for their services as directors. Directors who are not employees of NRG or Northern States Power will receive an annual fee of $30,000 and a fee of $1,000 per meeting plus reasonable travel expenses. Non-

employee directors are also entitled to participate in the NRG 2000 Long-Term Incentive Compensation Plan, as described below. Following the offering we expect to issue options to purchase 5,000 shares of our common stock to each of our independent directors.

Each of our directors has an indemnification agreement that entitles them to indemnification for claims asserted against them in their capacity as directors to the fullest extent permitted by Delaware law.

COMPENSATION OF EXECUTIVE OFFICERS AND OTHER INFORMATION

The following table shows the cash compensation paid or to be paid by us or any of our subsidiaries, as well as certain other compensation paid or accrued, during the fiscal years indicated to our Chief Executive Officer and our four next highest paid executive officers, which we refer to as our "Named Executives," in all capacities in which they serve:

SUMMARY COMPENSATION TABLE

	ANNUAL COMPENSATION				LONG-TERM COMPENSATION	
NAME AND PRINCIPAL POSITION	YEAR	SALARY	BONUS	OTHER ANNUAL COMPENSATION(1)	LTIP PAYOUTS	ALL OTHER COMPENSATION
David H. Peterson	1999	$367,992	$192,970	$6,131	$155,995	$33,201(2)
Chairman, President and Chief Executive	1998	345,826	290,220	4,922	7,724	17,777
Officer	1997	300,000	127,000	3,272	0	15,517
Craig A. Mataczynski	1999	246,250	150,000	4,706	15,533	15,251(3)
Senior Vice President, North America	1998	192,091	118,627	3,871	2,538	5,832
	1997	163,336	60,804	1,347	0	39,962
Ronald J. Will	1999	214,160	83,564	5,162	50,075	15,275(4)
Senior Vice President,	1998	188,640	107,341	4,130	3,182	5,597
Europe	1997	163,507	38,667	1,627	0	4,870
James J. Bender	1999	213,746	100,000	6,528	19,729	6,172(5)
Vice President, General Counsel and	1998	198,758	108,892	7,331	4,810	49,491
Corporate Secretary	1997	93,282	89,750(6)	6,239	0	42,391
Leonard A. Bluhm	1999	194,590	72,150	5,265	50,489	12,814(7)
Executive Vice President	1998	189,174	66,500	5,156	3,172	5,060
and CFO	1997	179,586	48,190	2,462	0	4,581

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(1) Amounts reimbursed during the fiscal year for the payment of taxes on fringe benefits.

(2) Includes a $15,481 excess vacation payout; $8,707 of Incentive Pension Makeup Plan contributions; $7,000 of universal life insurance premiums; $1,114 of Employee Stock Ownership Plan contributions; and $900 of 401(k) Plan matching contributions.

(3) Includes a $9,308 excess vacation payout; $3,559 of Incentive Pension Makeup Plan contributions; $1,114 of Employee Stock Ownership Plan contributions; $900 of 401(k) Plan matching contributions; and $370 of term life insurance premiums.

(4) Includes a $9,288 excess vacation payout; $3,220 of Incentive Pension Makeup Plan contributions; $1,114 of Employee Stock Ownership Plan contributions; $900 of 401(k) Plan matching contributions; and $752 of term life insurance premiums.

(5) Includes $3,267 of Incentive Pension Makeup Plan contributions; $1,114 of Employee Stock Ownership Plan contributions; $900 of 401(k) Plan matching contributions; and $1,406 of term life insurance premiums.

(6) Includes $25,000 paid as a signing bonus.

(7) Includes a $7,399 excess vacation payout; $1,995 of Incentive Pension Makeup Plan contributions; $1,114 of Employee Stock Ownership Plan contributions; $900 of 401(k) Plan matching contributions; and $752 of term life insurance premiums.

STOCK OWNERSHIP OF DIRECTORS AND EXECUTIVE OFFICERS

All of our stock is currently owned by Northern States Power and thus none of our officers and directors owns any of our common stock.

The following table sets forth certain information with respect to the beneficial ownership of Northern States Power's common stock by each director, certain of our executive officers and all of our directors and

executive officers as a group. Except as otherwise indicated in the footnotes, each individual has sole voting and investment power with respect to the shares set forth in the following table.

NAME OF BENEFICIAL OWNER	SHARES BENEFICIALLY OWNED(1)	PERCENT OF CLASS(2)	SHARES INDIVIDUALS HAVE RIGHTS TO ACQUIRE WITHIN 60 DAYS(3)
	SHARES BENEFICIALLY OWNED INCLUDE		
David H. Peterson	23,664	*	8,839
Gary R. Johnson	81,493	*	69,245
Cynthia L. Lesher	59,262	*	46,517
Edward J. McIntyre	124,928	*	97,840
Leonard A. Bluhm	10,859	*	5,679
Craig A. Mataczynski	2,929	*	1,546
Ronald J. Will	17,063(4)	*	5,444
James J. Bender	211	*	0
All executive officers and directors as a group (15 persons)	434,435	*	314,534

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* Less than one percent of outstanding shares.

(1) Beneficial ownership means the sole or shared power to vote, or to direct the voting of, a security, or investment power with respect to a security, or any combination thereof.

(2) Based on 156,589,316 shares of Northern States Power common stock outstanding on March 15, 2000.

(3) Indicates shares of the Northern States Power common stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

(4) Includes 4,467 shares that are held solely by Mr. Will's spouse in which he disclaims any interest.

STOCK OPTION HOLDINGS

The following table sets forth information concerning fiscal year-end value of unexercised options held by the Named Executives under the Northern States Power Executive Stock Option Program. Prior to the existence of the NRG Equity Plan, NRG executives participated in the Northern States Power Executive Stock Option Program.

AGGREGATED OPTION/SAR FISCAL YEAR-END VALUES

NAME	NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS/SARS AT FY-END(1) EXERCISABLE/UNEXERCISABLE	VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS/SARS AT FY-END(2) EXERCISABLE/UNEXERCISABLE
David H. Peterson	16,879/0	$29,583/$0
Leonard A. Bluhm	6,593/0	$ 8,992/$0
Craig A. Mataczynski	1,545/0	$ 959/$0
Ronald J. Will	5,457/0	$ 8,846/$0
James J. Bender	0/0	$ 0/$0

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(1) These options to acquire Northern States Power Stock were granted to the Named Executives for services rendered to NRG and its subsidiaries.

(2) Northern States Power's share price on December 31, 1999 was $19.50.

PENSION PLAN

We participate in Northern States Power's noncontributory, defined benefit pension plan that covers substantially all of our employees. As of January 1, 1999, pension benefits were changed. Prior to

January 1, 1999, each nonbargaining employee was given an opportunity to choose between two retirement programs, the traditional program and the pension equity program.

Under the traditional program, the pension benefit is computed by taking the highest average compensation multiplied by credited years of service with a 50% offset for social security benefits. The annual compensation used to calculate the average compensation uses base salary for the year and bonus compensation paid in that same year. After an employee has reached 30 years of service, no additional years of service are used in determining the pension benefit under the traditional program. The benefit amounts under the traditional program are computed in the form of a straight-line annuity.

Under the pension equity program, the annual compensation used to calculate average compensation uses base salary for the year and bonus compensation paid in that same year, with no maximum on the number of years used to determine the pension benefit. The benefit amounts under the pension equity program are computed in the form of a lump sum. The formula for determining the lump sum is average compensation multiplied by credited years of service times 10% with a 50% offset for social security. The benefit amounts can be paid in a lump sump or in the form of a straight-line annuity, at the option of the employee.

Both programs feature a cash balance side account, which credits $1,400 annually, plus interest each year. The opening balance as of January 1, 1999 is $1,400 times years of service.

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

	ESTIMATED ANNUAL BENEFITS FOR YEARS OF SERVICE INDICATED					
	YEARS OF SERVICE					
AVERAGE COMPENSATION (LAST 4 YEARS)	5	10	15	20	25	30
50,000	$ 3,500	$ 7,000	$10,500	$ 14,000	$ 18,000	$ 21,500
100,000	7,500	15,500	23,000	30,500	38,000	46,000
150,000	11,500	23,500	35,000	47,000	58,500	70,500
200,000	16,000	31,500	47,500	63,000	79,000	95,000
250,000	20,000	40,000	59,500	79,500	99,500	119,500
300,000	24,000	48,000	72,000	96,000	120,000	144,000
350,000	28,000	56,000	84,000	112,500	140,500	168,500
400,000	32,000	64,500	96,500	128,500	160,500	193,000
450,000	36,000	72,500	108,500	144,500	181,000	217,000
500,000	40,500	80,500	121,000	161,000	201,500	241,500
550,000	44,500	88,500	133,000	177,500	221,500	266,000
600,000	48,500	97,000	145,500	193,500	242,000	290,500
650,000	52,500	105,000	157,500	210,000	262,500	315,000
700,000	56,500	113,000	170,000	226,500	283,000	339,500
750,000	60,500	121,500	182,000	242,500	303,500	364,000

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 if paid in the form of a straight-line annuity:

ESTIMATED ANNUAL BENEFITS FOR YEARS OF SERVICE INDICATED
YEARS OF SERVICE

AVERAGE COMPENSATION (LAST 4 YEARS)	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

As of March 31, 2000, each of the Named Executives had the following credited service: Mr. Peterson, 36 years, Mr. Bluhm, 29 years, Mr. Mataczynski, 18 years, Mr. Will, 40 years, and Mr. Bender, 5 years. Mr. Mataczynski and Mr. Bender have selected the pension equity program; all other Named Executives have selected the traditional program.

LONG-TERM INCENTIVE PLAN COMPENSATION

The following table sets forth information concerning awards during fiscal 1999 to each of the Named Executives under the NRG Equity Plan, described below.

LONG-TERM INCENTIVE PLAN AWARDS IN LAST FISCAL YEAR

NAME	UNITS OR OTHER RIGHTS (#)	PERFORMANCE OR OTHER PERIOD UNTIL MATURATION OR PAYOUT
David H. Peterson.............................	41,080	8 years
Leonard A. Bluhm..............................	9,070	8 years
Craig A. Mataczynski..........................	12,100	8 years
Ronald J. Will................................	10,000	8 years
James J. Bender...............................	10,000	8 years

NRG EQUITY PLAN

Prior to the offering, our officers and other selected employees participated in the NRG Equity Plan. This discretionary plan was established in 1993 to promote the achievement of long-term financial objectives by linking the long-term incentive compensation of our employees to the achievement of value creation; to attract and retain employees of outstanding competence; to encourage teamwork among employees; and to provide employees with an opportunity for long-term capital accumulation. The plan provided grants of "equity units" that were intended to simulate stock options. Grant size was based on the participant's position in the company and base salary. The Compensation Committee of the board of directors administered the plan for our officers. The Chief Executive Officer administered the plan for other employees.

Equity grants were generally made annually at the discretion of the board of directors with the grant price consistent with the most recent valuation of equity units. Equity unit valuations were performed annually by a nationally recognized outside valuation firm selected by the board of directors. The value of an equity unit is the approximate value per share of our stockholder equity as of the valuation date, less the value of Northern States Power equity investments. The accrued value of each participant's award is equal to the current value of the equity unit minus the grant price. Equity units are paid out in cash over a five-year period (twenty percent per year) following a three-year vesting period. In the event of termination of employment by a participant due to death or disability, outstanding equity units become fully vested and are fully paid in the following year. In the event of termination of employment due to retirement, outstanding equity units become fully vested and are paid out pro rata over the five plan years following termination. Termination of a participant for any other reason results in forfeiture of all unvested equity units, unless otherwise approved.

Following the offering we do not plan to make any additional grants under this plan. Currently there are approximately 1,510,000 equity units outstanding. Of that amount, approximately 629,000 equity units are held by our officers. Approximately 881,000 equity units are held by other employees, retirees and transferees. No non-employee directors have participated in this plan.

With the establishment of the NRG 2000 Long-Term Incentive Compensation Plan, the NRG Equity Plan will be discontinued. All outstanding, non-vested equity units for active employee participants will be terminated, and a comparable stock option grant issued in replacement of the unvested equity unit grant. Options for approximately 3,300,000 shares of common stock will be issued under the new plan for this purpose. Messrs. Peterson, Bluhm, Mataczynski, Will and Bender and all executive officers as a group will be granted such options in replacement of equity units for approximately 621,000; 177,000; 126,000; 179,000; 116,000 and 1,484,000 shares, respectively, under this Plan at the consummation of this offering.

Following the offering, equity units held by retired, terminated and transferred participants will be valued on the basis of the fair market value of our common stock and payouts will occur upon vesting as provided in the existing Equity Plan. Final payouts under this plan to non-employee participants should occur no later than 2006.

NRG 2000 LONG-TERM INCENTIVE COMPENSATION PLAN

Prior to the completion of the offering, we expect to adopt a new incentive compensation plan that will replace the NRG Equity Plan. The board of directors or a committee appointed by the board of directors will administer the incentive plan. The incentive plan will provide 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 will be eligible to participate in the incentive plan. The total number of shares of common stock to be authorized for issuance under the incentive plan is 9,000,000 shares.

Initially, as of the completion of this offering, only stock option grants will be made to certain officers and employees under the incentive plan. The initial options will have an exercise price equal to the initial public offering price. The vesting period for the initial awards will be 5 years with 25% vesting in each of the years two through five. Subsequent awards, expected to be issued annually, will have an option price at least equal to the market price of our common stock on the date of grant. Options will vest over a four-year period from the date of grant, 25 percent each year. Each option granted will expire at such time as the board of directors determines at the time of grant; provided, however, that no option that is intended to qualify as an "Incentive Stock Option" within the meaning of Section 422 of the Internal Revenue Code shall be exercisable later than the tenth (10th) anniversary date of its grant. The total number of shares of common stock covered by the initial grant is expected to be approximately 1,100,000 shares. Messrs. Peterson, Bluhm, Mataczynski, Will and Bender and all executive officers as a group will be granted initial options for 120,000; 60,000; 60,000; 60,000; 60,000; and 600,000 shares, respectively.

In addition, non-vested equity units outstanding under the NRG Equity Plan will be converted into stock options with an exercise price corresponding to the original equity plan grant price. Vesting and all

other material terms of the equity plan shall continue as the terms of these options. Once vested, the awards shall remain exercisable for up to 10 years from date of the grant under the equity plan, except that the January 1993 and January 1994 grants shall terminate 90 days following the end of the original 10 year vesting period.

To the extent issuance of equity compensation under the incentive plan would cause Northern States Power to cease to own at least 80% of the value of our outstanding capital stock, Northern States Power may purchase shares of common stock in the open market to ensure that such minimum value is maintained.

EMPLOYMENT CONTRACTS

David H. Peterson. We have entered into an employment agreement with Mr. Peterson providing that Mr. Peterson will be employed as our highest level executive officer. The term of the agreement expires June 27, 2004. During the term of the agreement, Mr. Peterson's base salary will be reviewed at least annually by the Compensation Committee of the board of directors for possible increase. The agreement provides that Mr. Peterson will receive retirement and welfare benefits no less favorable than those provided to any of our other officers. In addition, the employment agreement provides for participation in a supplemental executive retirement plan such that the aggregate value of the retirement benefits that Mr. Peterson and his spouse will receive at the end of the term of the agreement under all of our defined benefit pension plans and those of our affiliates will not be less than the aggregate value of the benefits he would have received had he continued, through the end of the term of the agreement, to participate in the Northern States Power's Deferred Compensation Plan, the Northern States Power Excess Benefit Plan and the Northern States Power Pension Plan, including amounts to compensate Mr. Peterson for the monthly defined benefit payments he would have received during the term of the employment agreement and prior to the date of his termination of employment if monthly benefit payments had commenced following the month in which he first became eligible for early retirement under the Northern States Power Pension Plan.

The employment agreement also provides for certain additional benefits to be paid upon Mr. Peterson's death. If Mr. Peterson's employment is terminated by us without cause or by Mr. Peterson with good reason, in each case as defined in the employment agreement, Mr. Peterson will continue to receive his salary, bonus at the greater of target bonus and actual bonus for the last plan year prior to termination, incentive compensation with cash replacing equity based awards and benefits under the agreement as if he had remained employed until the end of the term of the employment agreement and then retired, at which time he will be treated as eligible for retiree welfare benefits and other benefits provided to the retired senior executives. However, if the termination of employment is a result of a change of control, as defined in the NRG Equity Plan, the compensation and benefits will be continued for the longer of 30 months or through the end of the employment period. In accordance with the terms of the employment agreement, Mr. Peterson has agreed not to compete with our business during the period of his employment and for one year after his termination or resignation. Mr. Peterson has also agreed not to solicit any of our customers for any business purpose that competes with our business during the period of his employment or two years after his termination or resignation. Finally, during the period of his employment and for two years after his termination or resignation, Mr. Peterson has agreed not to disclose any of our confidential information to any person not authorized by us to receive it.

Leonard A. Bluhm, Craig A. Mataczynski, Ronald J. Will and James J. Bender. On April 15, 1998, we entered into employment agreements with each of Messrs. Bluhm, Mataczynski, Will and Bender. These agreements expire on April 15, 2001. If the employment of any of Messrs. Bluhm, Mataczynski, Will and Bender is terminated due to his death, disability or for cause, or if any of them voluntarily resigns without good cause, he will receive his base salary excluding incentives and employee benefits through the date of termination or resignation. However, if any of the executives is terminated for any reason other than death, disability or cause, or if any of them voluntarily resigns for good cause, we will be obligated to continue to pay his then current total compensation, including base salary, anticipated incentives and all employee benefits for a period of three years following the date of termination or resignation. Under the terms of the employment agreements, each of the executives has agreed not to compete with our business during the course of his employment and for one year after his resignation or termination. In addition, each of the executives has agreed not to disclose any of our confidential information or trade secrets or use the information for his or a third party's benefit. The employment agreement with Mr. Will also provides that upon Mr. Will's termination of employment for any reason or his voluntary resignation with or without good cause, in addition to all other items of compensation, we will pay the sum of $100,000 as a retainer in exchange for Mr. Will's agreement to make himself available at our request to provide consulting services for one year following his termination or resignation.

OWNERSHIP OF CAPITAL STOCK

Prior to the completion of this offering, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401, owned all of our outstanding capital stock.

Upon completion of this offering, Northern States Power will own 147,604,500 shares of class A common stock. Upon completion of this offering, class A common stock will constitute approximately 84% of our total outstanding common equity and approximately 98% of our total voting power. Upon completion of this offering, common stock will constitute approximately 16% of our total outstanding stock and approximately 2% of our total voting power.

RELATIONSHIPS AND RELATED TRANSACTIONS

The transactions described or referred to below were entered into between related parties prior to the offering of our common stock and were not the result of arms-length negotiations.

Northern States Power has the power, and will continue to have the power following this offering, to control the election of the directors and all other matters submitted for stockholder approval and may be deemed to have control over our management and affairs. Northern States Power has policies in place, pursuant to applicable law, to ensure that its ratepayers are protected from affiliate transactions that may be adverse to the ratepayers' interests. Unless otherwise noted below, the agreements described below will continue in effect after this offering.

OPERATING AGREEMENTS

We have two agreements with Northern States Power for the purchase of thermal energy. Under the terms of the agreements, Northern States Power charges us for certain incremental costs, including fuel, labor, plant maintenance and auxiliary power, incurred by Northern States Power to produce the thermal energy. We paid Northern States Power $4.6 million in 1997, $5.1 million in 1998 and $4.4 million in 1999 under these agreements; we have paid $1.4 million under them in the first three months of 2000. One of the agreements expires on December 31, 2002 and the other one expires on December 31, 2006.

We have a renewable 10-year agreement with Northern States Power, expiring on December 31, 2001, whereby Northern States Power agrees to purchase refuse-derived fuel for use in certain of its boilers and we agree to pay Northern States Power an incentive fee to use refuse-derived fuel. Under this agreement, we received from Northern States Power $1.3 million in 1997, $1.4 million in 1998 and $1.4 million in 1999; we paid to Northern States Power $2.8 million in 1997, $3.1 million in 1998 and $2.7 million in 1999 under this agreement. Through March 31, 2000, we received $0.6 million and paid $0.5 million.

We have entered into an operation and maintenance agreement with Northern

States Power with respect to the Elk River and Becker facilities, under which we receive a base management fee and are reimbursed for costs we have incurred. The operation and maintenance agreement also provides for a management incentive fee payable to us, based upon the financial performance of the facilities. We earned a total management fee of $1.1 million, in addition to reimbursed expenses, in 1997, $1.7 million in 1998 and $1.9 million in 1999. Management fees for the three months ended March 31, 2000, totaled $0.6 million. This agreement expires on December 31, 2003.

ADMINISTRATIVE SERVICES AGREEMENT

We have entered into an agreement with Northern States Power to provide for the reimbursement of actual administrative services provided to each other on an at-cost basis plus a 1% fee to cover handling costs, working capital requirements and other miscellaneous costs. Services provided by Northern States Power to us are principally for cash management, accounting, employee relations, governmental affairs and engineering. In addition, our employees participate in certain employee benefit plans of Northern States Power. We paid Northern States Power $0.7 million in 1997, $5.2 million in 1998 and $6.4 million in 1999, as reimbursement for the cost of services provided. Through March 31, 2000, we have paid $2.0 million.

TAX SHARING AGREEMENT

We are included in the consolidated federal income tax and state franchise tax returns of Northern States Power. We calculate our tax position on a separate company basis under a tax sharing agreement with Northern States Power and receive payment from Northern States Power for tax benefits they receive by our inclusion on their tax returns and pay Northern States Power for tax liabilities created by such inclusion.

LONG-TERM DEBT

The construction cost of the Newport facilities was financed through tax exempt variable rate resource recovery revenue bonds issued by the two Minnesota counties served by the facilities, which have subsequently been converted to fixed rate resource recovery revenue bonds with an effective interest rate of 6.57% per annum and annual maturities each December through 2006. The proceeds of such bond issuance were loaned by the counties to Northern States Power, which agreed under a loan agreement to pay to the counties amounts sufficient to pay debt service on the bonds. We issued a separate note to Northern States Power in an original principal amount of approximately $10 million as part of the consideration for the purchase of the facility from Northern States Power.

OPTION AGREEMENT

Before this offering is completed, we will enter into an option agreement with Northern States Power under which we will grant to Northern States Power and its affiliates a continuing option to purchase additional shares of common stock. If we issue any additional equity securities after this offering, Northern States Power and its affiliates may exercise this option to purchase shares of common stock to the extent necessary for them to maintain an ownership percentage of 80% of the outstanding shares of common stock and Class A common stock on a combined basis.

The stock option expires if Northern States Power and its affiliates beneficially own less than 30% of the outstanding common stock and class A common stock on a combined basis.

REGISTRATION RIGHTS AGREEMENT

Prior to consummation of this offering, we will enter into a registration rights agreement with Northern States Power, under which we will agree to register the shares of common stock issuable upon conversion of shares of class A common stock held by Northern States Power under the following circumstances:

- Demand Rights. Upon the written request of Northern States Power, we will register shares of common stock held by Northern States Power specified in its request for resale under an appropriate registration statement filed and declared effective by the Securities and Exchange Commission. Northern States Power may make a demand so long as:

  - it requests registration of shares with an anticipated aggregate offering price of at least $20 million;

  - it has made no more than four such previous requests;

  - we have not completed a registered offering of common stock within the last 180 days; and

  - our chief executive officer has not determined it advisable to delay the offering for a period of up to 180 days, which determination may only be made once every twelve months.

- Piggyback Rights. If at any time we register newly issued shares of common stock, or register outstanding shares of common stock for resale on behalf of any holder of our common stock, Northern States Power may elect to include in such registration any shares of common stock it holds. If the offering is an underwritten offering, the managing underwriter may exclude up to 75% of Northern States Power's shares if market factors dictate, but only if Northern States Power is not exercising a demand right, described above, and only if all other shares being sold by other stockholders are excluded first.

- Lockup. In consideration for these registration rights, Northern States Power has agreed not to sell shares of common stock for a period of 180 days following the date of this prospectus.

- Termination. The registration rights agreement will terminate upon the earlier of seven years from the date of the agreement or the date on which all remaining shares of common stock held by Northern States Power, or issuable to Northern States Power upon conversion of class A common stock, may be sold in any 90-day period in compliance with Rule 144 under the Securities Act.

DESCRIPTION OF CAPITAL STOCK

AUTHORIZED STOCK

The authorized capital stock of NRG consists of 550,000,000 shares of common stock, $0.01 par value, 250,000,000 shares of class A common stock, $0.01 par value and 200,000,000 shares of preferred stock, $0.01 par value. All of the issued and outstanding capital stock is fully paid and nonassessable. The following summary of the shares of common stock, class A common stock and preferred stock is qualified by reference to our certificate of incorporation, a copy of which we will provide to you upon your request, and a copy of which is filed as an exhibit to the registration statement to which this prospectus relates.

COMPARISON OF OUR COMMON STOCK AND CLASS A COMMON STOCK

The following table compares our common stock and class A common stock.

	COMMON STOCK	CLASS A COMMON STOCK
Public Market..................	The common stock has been approved for listing on the NYSE, subject to official notice of issuance.	None.
Voting Rights..................	One vote per share on all matters voted upon by our	Ten votes per share on all matters voted upon by our

	stockholders.	stockholders.
Transfer Restrictions..........	None.	None, but will convert to common stock on a share-for-share basis upon certain transfers as described below.
Conversion.....................	Not convertible.	Convertible at any time, in whole or in part, into shares of common stock on a share-for-share basis. Automatically converts into common stock on a share-for-share basis upon any transfer to a non-affiliate of Northern States Power (including by way of merger, consolidation or reorganization other than in connection with the formation of Xcel Energy) or if Northern States Power or its affiliates own less than 30% of the outstanding shares of class A common stock and common stock on a combined basis.
Reissuance.....................	Additional shares may be issued and redeemed shares may be reissued.	No additional shares may be issued, and shares redeemed or repurchased will be canceled and may not be reissued.

PREFERRED STOCK

Our board of directors has the authority to issue shares of preferred stock from time to time on terms that it may determine, to divide preferred stock into one or more classes or series, and to fix the designations, voting powers, preferences and relative participating, option or other special rights of each class or series, and the qualifications, limitations or restrictions of each class or series, to the fullest extent permitted by Delaware law. The issuance of preferred stock could have the effect of decreasing the market price of our common stock, impeding or delaying a possible takeover and adversely affecting the voting and other rights of the holders of common stock. Currently, there are no shares of preferred stock outstanding and there are no shares of preferred stock designated.

OTHER PROVISIONS RELATING TO COMMON STOCK AND CLASS A COMMON STOCK

If we in any manner split, subdivide or combine the outstanding shares of common stock or class A common stock, the outstanding shares of the other class of common stock will be proportionally subdivided or combined in the same manner and on the same basis.

In all other respects, whether as to dividends, upon liquidation, dissolution or winding up, or otherwise, the holders of record of common stock and the holders of record of class A common stock have identical rights and privileges on the basis of the number of shares held.

ADVANCE NOTICE REQUIREMENTS FOR STOCKHOLDER PROPOSALS

Our bylaws provide that stockholders seeking to bring business before an annual meeting of stockholders must provide timely notice of their proposal in writing to the corporate secretary. To be timely, a stockholder's notice must be delivered or mailed and received at our principal executive offices not less than 120 days in advance of the anniversary date of our proxy statement in connection with our previous year's annual meeting. Our bylaws also specify requirements as to the form and content of a stockholder's notice. These provisions may impede stockholders' ability to bring matters before an annual meeting of stockholders or make nominations for directors at an annual meeting of stockholders. So long as Northern States Power or its successors by way of merger or consolidation own at least 50% of the outstanding shares of common stock and class A common stock on a combined basis, it will be exempt from these provisions.

SPECIAL MEETINGS

Holders of our common stock may not call a special meeting of stockholders; only our board of directors may call such a meeting.

BUSINESS COMBINATIONS WITH INTERESTED STOCKHOLDERS

We will not be subject to the business combination provisions of Section 203 of the Delaware General Corporation Law, but our certificate of incorporation will contain provisions substantially similar to Section 203. In general, these provisions will prohibit us from engaging in various business combination transactions with any interested stockholder for a period of two years after the date of the transaction in which the person became an interested stockholder unless one of the following three sets of conditions are satisfied:

- the business combination transaction is approved by a majority of the members of our board of directors who either are unaffiliated with the interested stockholder and were members prior to the date the interested stockholder obtained this status or were nominated and elected by a majority of such unaffiliated members,

- several conditions are met including that the aggregate amount of cash and the fair market value as of the date of the consummation of the transaction of non-cash consideration to be received per share by a holder of our capital stock is at least equal to the highest of

  - the highest per share price paid by the interested stockholder within the previous two years or in the transaction in which the interested stockholder obtained this status;

  - the fair market value per share of the relevant class of capital stock on the date the transaction was announced; and

  - the fair market value per share of the relevant class of capital stock on the date the interested stockholder obtained this status; and

  a proxy or information statement describing the proposed business combination has been mailed to our stockholders at least 30 days prior to the consummation of such business combination; or

- the business combination is approved by our board of directors and authorized at an annual or special meeting of stockholders by the affirmative vote of at least 80% of our outstanding shares entitled to vote for the election of directors.

Under our certificate of incorporation, a business combination is defined to include mergers, asset sales and other transactions resulting in financial benefit to a stockholder. In general, an interested stockholder is a person who, together with affiliates and associates, owns or, within two years, did own, 10% or more of our common stock. Northern States Power and its affiliates, including Xcel Energy upon the completion of Northern States Power's pending merger, will be exempt from these provisions.

AMENDMENT

Our certificate of incorporation also provides that, after the first date that Northern States Power or Xcel Energy, together with their respective affiliates, ceases to beneficially own at least 30% of the outstanding shares of common stock and class A common stock on a combined basis, the affirmative vote of the holders of at least 80% of the outstanding shares of common stock and class A common stock on a combined basis is required to amend the provisions of our certificate of incorporation described above under "-- Advance Notice Requirements for Stockholder Proposals," "-- Special Meetings," and "-- Business Combinations with Interested Stockholders." Under our certificate of incorporation and by-laws, our by-laws may only be amended:

- at any time by the affirmative vote of directors constituting not less than a majority of the entire board of directors;

- prior to the first date that Northern States Power or Xcel Energy, together with their respective affiliates, cease to beneficially own at least 50% of the outstanding shares of the outstanding shares of common stock and class A common stock on a combined basis, by the affirmative vote of the holders of a majority of the outstanding shares of common stock and class A common stock on a combined basis; or

- after that date, by the affirmative vote of the holders of a least 80% of the outstanding shares of common stock and class A common stock on a combined basis.

REGISTRATION RIGHTS

We have agreed to register shares of our common stock on behalf of Northern States Power as described in "Relationships and Related Transactions -- Registration Rights Agreement."

LIMITATIONS ON LIABILITY AND INDEMNIFICATION OF OFFICERS AND DIRECTORS

The Delaware General Corporation Law authorizes corporations to limit or eliminate the personal liability of directors to corporations and their stockholders for monetary damages for breaches of directors' fiduciary duties. Our certificate of incorporation includes a provision that eliminates the personal liability of directors for monetary damages for actions taken as a director, except for liability:

- for breach of duty of loyalty;

- for acts or omissions not in good faith or involving intentional misconduct or knowing violation of law;

- under Section 174 of the Delaware General Corporation Law (unlawful dividends); and

- for transactions from which the director derived improper personal benefit.

Our bylaws provide that we must indemnify our directors and officers to the fullest extent authorized by the Delaware General Corporation Law, subject to very limited exceptions. We are also expressly authorized to carry directors' and officers' insurance providing indemnification for our directors, officers and certain employees for some liabilities. We believe that these indemnification provisions and insurance are necessary to attract and retain qualified directors and executive officers.

The limitation of liability and indemnification provisions in our certificate of incorporation, bylaws and indemnification agreements may discourage stockholders from bringing a lawsuit against directors for breach of their fiduciary duty. These provisions may also have the effect of reducing the likelihood of derivative litigation against directors and officers, even though such an action, if successful, might otherwise benefit us and our stockholders. In addition, your investment may be adversely affected to the extent we pay the costs of settlement and damage awards against directors and officers pursuant to these indemnification provisions.

There is currently no pending litigation or proceeding involving any of our directors, officers or employees for which indemnification is sought. We are unaware of any pending or threatened litigation that may result in claims for indemnification.

TRANSFER AGENT

Norwest Bank, N.A. will act as the transfer agent for the common stock.

DESCRIPTION OF INDEBTEDNESS

$125 MILLION 7.625% SENIOR NOTES DUE 2006; $250 MILLION 7.5% SENIOR NOTES DUE 2007; AND $300 MILLION 7.5% SENIOR NOTES DUE 2009

In January 1996, we sold $125 million of 7.625% Senior Notes due 2006 in a transaction exempt from registration under the Securities Act. All of the 7.625% Senior Notes due 2006 are still outstanding.

In June 1997, we sold $250 million of 7.5% Senior Notes due 2007 in a transaction exempt from registration under the Securities Act. On January 20, 1998, we issued in an offering registered under the Securities Act an aggregate principal amount of $250 million of 7.5% Senior Notes due 2007 in exchange for all the unregistered 7.5% Senior Notes due 2007 issued on June 17, 1997. All of the 7.5% Senior Notes due 2007 are still outstanding.

In May 1999, we sold $300 million of 7.5% Senior Notes due 2009 in an offering registered under the Securities Act. All of the 7.5% Senior Notes due 2009 are still outstanding.

Each of the 7.625% Senior Notes due 2006, the 7.5% Senior Notes due 2007 and the 7.5% Senior Notes due 2009 are governed by the terms of an indenture. The material terms of the indentures are described below. As a summary, the following discussion necessarily omits many of the details of the indentures. A copy of each of the indentures has been filed as an exhibit to the registration statement of which this prospectus is a part.

Interest on the 7.625% Senior Notes due 2006 is payable semiannually in arrears on each February 1 and August 1. Interest on the 7.5% Senior Notes due 2007 is payable semiannually in arrears on each June 15 and December 15. Interest on the 7.5% Senior Notes due 2009 is payable semiannually in arrears on each June 1 and December 1.

OPTIONAL REDEMPTION

The 7.625% Senior Notes due 2006 are redeemable, in whole or in part, at any time after February 1, 2001, and the 7.5% Senior Notes due 2007 and the 7.5% Senior Notes due 2009 are redeemable, in whole or in part, at any time. In each case, the redemption price to be repaid is the greater of:

- 100% of principal amount of the senior notes, plus accrued interest on the principal amount, if any, to the redemption date; or

- a discounted sum of the present values of all of the remaining scheduled payments of principal and interest from the redemption date to maturity on the senior notes.

CHANGE OF CONTROL

If a change of control occurs (as defined in the relevant indenture), we must make an offer to purchase all outstanding 7.625% Senior Notes due 2006, 7.5% Senior Notes due 2007 and 7.5% Senior Notes due 2009 at a purchase price equal to 101% of their principal amount plus accrued and unpaid interest. This requirement could deter a change of control transaction in which stockholders could receive a premium. However, no change of control will be deemed to have occurred if the rating remains investment grade.

COVENANTS RESTRICTING OUR ACTIONS

Each of the indentures contains covenants which generally prohibit or restrict our ability to pledge, mortgage, hypothecate or permit to exist any lien upon our property to secure any indebtedness for borrowed money unless the senior notes are equally and ratably secured. In addition, the indenture for the 7.625% Senior Notes due 2006 requires us to maintain a tangible net worth of greater than the sum of $175 million plus 25% of our consolidated net income for the period from and including April 1, 1996 to the determination date of such income.

EVENTS OF DEFAULT

The following are "events of default" under each of the indentures:

- our failure to pay any interest on the senior notes when due, which failure continues for 30 days;

- our failure to pay principal or premium (including in connection with a change of control) on the senior notes when due;

- our failure to perform any other covenant relating to the senior notes for a period of 30 days after the trustee gives us written notice or we receive written notice by the holders of at least 25% in aggregate principal amount of the senior notes;

- an event of default occurring under any of our instruments under which there may be issued, or by which there may be secured or evidenced, any indebtedness for money borrowed that has resulted in the acceleration of the indebtedness, or any default occurring in payment of any indebtedness at final maturity and after the expiration of any applicable grace periods, other than:

  - indebtedness that is payable solely out of the property or assets of a partnership, joint venture or similar entity of which we or any of our subsidiaries or affiliates is a participant, or that is secured by a lien on the property or assets owned or held by that entity without further recourse to us; or

  - indebtedness not exceeding $20 million;

- one or more final judgments, decrees or orders for the payment of money aggregating $20 million or more, either individually or in the aggregate, shall be entered against us and shall remain undischarged, unvacated and unstayed for more than 90 days, except while being contested in good faith by appropriate proceedings; and

- a bankruptcy, insolvency, reorganization or receivership or similar proceeding with respect to us.

$240 MILLION 8% REMARKETABLE OR REDEEMABLE SECURITIES ("ROARS") DUE 2013 (REMARKETING DATE NOVEMBER 1, 2003)

In November 1999, we sold $240 million of 8% ROARS due 2013 in an offering registered under the Securities Act. All of the 8% ROARS due 2013 are still outstanding and interest on them is payable semiannually in arrears on each November 1 and May 1.

The ROARS are governed by the terms of an indenture. The material terms of the indenture are described below. As a summary, the following discussion necessarily omits many of the details of the indenture. A copy of the indenture has been filed as an exhibit to the registration statement of which this prospectus is a part.

CHANGE OF CONTROL

If a change of control (as defined in the indenture) occurs, we must make an offer to purchase all outstanding ROARS then outstanding at a purchase price equal to 101% of their principal amount plus accrued and unpaid interest. This requirement could deter a change of control transaction in which stockholders could receive a premium. However, no change of control will be deemed to have occurred if the rating remains investment grade.

COVENANTS RESTRICTING OUR ACTIONS

The indenture for the ROARS contains covenants which generally prohibit or restrict our ability to pledge, mortgage, hypothecate or permit to exist any lien upon our property to secure any indebtedness for borrowed money unless the senior notes are equally and ratably secured.

EVENTS OF DEFAULT

The "events of default" under the indenture governing the ROARS are substantially equivalent to those previously described with respect to the senior notes.

MANDATORY TENDER

We have entered into a Remarketing Agreement with Credit Suisse Financial Products pursuant to which Credit Suisse has the option to purchase all of the ROARS on November 1, 2003 at a purchase price equal to 100% of the aggregate principal amount outstanding. The ROARS will be remarketed at a fixed rate of interest unless we have redeemed the ROARS or have exercised our option to have the ROARS remarketed at a floating rate of interest for up to twelve months following November 1, 2003. If we have elected to have the ROARS remarketed at a floating rate of interest for up to twelve months, Credit Suisse will have the option to purchase all of the ROARS at the end of the applicable floating rate period at a discounted sum of the present values of all of the remaining scheduled payments of principal and interest from the redemption date to maturity on the ROARS.

OPTIONAL REDEMPTION

If Credit Suisse exercises its purchase option on November 1, 2003 or at the end of the applicable floating rate period, if any, we have the option of redeeming all of the ROARS at a discounted sum of the present values of all of the remaining scheduled payments of principal and interest from the redemption date to maturity on the ROARS.

MANDATORY REDEMPTION

We will be required to redeem the ROARS in whole on November 1, 2003 or at the end of any floating rate period in the event that Credit Suisse elects not to exercise its option to purchase the ROARS. If we are required to redeem the ROARS, we will redeem them at a purchase price equal to:

- if redeemed on November 1, 2003, 100% of the aggregate principal amount outstanding; or

- if redeemed at the end of any floating rate period, a discounted sum of the present values of all of the remaining scheduled payments of principal and interest from the redemption date to maturity on the ROARS.

L160 MILLION 7.97% RESET SENIOR NOTES DUE 2020

In March 2000, we sold L160 million (approximately $250 million at the time of issuance) of 7.97% Reset Senior Notes due 2020 in a transaction exempt from registration under the Securities Act. All of the 7.97% Reset Senior Notes were sold to the NRG Energy Pass-Through Trust 2000-1, a trust formed pursuant to a trust agreement between us and The Bank of New York, as trustee. The trust issued $250 million aggregate principal amount of certificates that represented an undivided beneficial interest in the assets of the trust, which assets consist principally of the 7.97% Reset Senior Notes. Interest on the 7.97% Reset Senior Notes is payable semiannually in arrears on each September 15 and March 15.

The 7.97% Reset Senior Notes are governed by the terms of an indenture. The material terms of the indenture are described below. As a summary, the following discussion necessarily omits many of the details of the indenture. A copy of the indenture has been filed as an exhibit to the registration statement of which this prospectus is a part.

CHANGE OF CONTROL

If a change of control (as defined in the indenture) occurs on or before March 15, 2005 we must make an offer to purchase all 7.97% Reset Senior Notes then outstanding at a purchase price in pounds sterling equal to 100% of their principal amount plus accrued and unpaid interest plus a payment in US dollars equal to 1% of the principal amount of trust certificates to be redeemed by the trust pursuant to a

similar change of control offer under the trust agreement. If a change of control occurs prior to March 15, 2005, but after an event of default that results in the principal amount of the 7.97% Reset Senior Notes being due and payable immediately, we may be required to purchase all or a part of the notes at a price in US dollars equal to 101% of the principal amount plus accrued and unpaid interest. If a change of control occurs after March 15, 2005, we must make an offer to purchase all 7.97% Reset Senior Notes then outstanding at a purchase price in pounds sterling equal to 101% of their principal amount plus accrued and unpaid interest. This requirement could deter a change of control transaction in which stockholders could receive a premium. However, no change of control will be deemed to have occurred if the rating remains investment grade.

COVENANTS RESTRICTING OUR ACTIONS

The indenture for our 7.97% Reset Senior Notes contains covenants which generally prohibit or restrict our ability to pledge, mortgage, hypothecate or permit to exist any lien upon our property to secure any indebtedness for borrowed money unless the reset senior notes are equally and ratably secured.

EVENTS OF DEFAULT

The "events of default" under the indenture governing the 7.97% Reset Senior Notes are substantially equivalent to those previously described with respect to the reset senior notes.

MANDATORY TENDER

We have entered into a Remarketing Agreement and a Call Agreement with affiliates of Bank of America, N.A. pursuant to which Bank of America has the option to purchase all of the 7.97% Reset Senior Notes on March 15, 2005 at a purchase price equal to 100% of the aggregate principal amount outstanding. The 7.97% Reset Senior Notes will be remarketed at a fixed rate of interest unless we have redeemed the 7.97% Reset Senior Notes or have exercised our option to have the 7.97% Reset Senior Notes remarketed at a floating rate of interest for up to twelve months following March 15, 2005. If we have elected to have the 7.97% Reset Senior Notes remarketed at a floating rate of interest for up to twelve months, Bank of America will have the option to purchase all of the 7.97% Reset Senior Notes at the end of the applicable floating rate period at a discounted sum of the present values of all of the remaining scheduled payments of principal and interest from the redemption date to maturity on the 7.97% Reset Senior Notes.

OPTIONAL REDEMPTION

If Bank of America exercises its purchase option on March 15, 2005 or at the end of the applicable floating rate period, if any, we have the option of redeeming all of the 7.97% Reset Senior Notes at a discounted sum of the present values of all of the remaining scheduled payments of principal and interest from the redemption date to maturity on the 7.97% Reset Senior Notes.

MANDATORY REDEMPTION

We will be required to redeem the 7.97% Reset Senior Notes in whole on March 15, 2005 or at the end any floating rate period in the event that Bank of America elects not to exercise its option to purchase the 7.97% Reset Senior Notes. If we are required to redeem the 7.97% Reset Senior Notes, we will redeem them at a purchase price equal to:

- if redeemed on March 15, 2005, 100% of the aggregate principal amount outstanding; or

- if redeemed at the end of any floating rate period, a discounted sum of the present values of all of the remaining scheduled payments of principal and interest from the redemption date to maturity on the 7.97% Reset Senior Notes.

ABN AMRO REVOLVING CREDIT FACILITY

In March 2000, we entered into a $500 million revolving credit facility with ABN AMRO Bank, N.V., as agent, and various lenders. 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 ABN AMRO's prime rate or the sum of the prevailing per annum rates for overnight funds plus 0.5% per annum plus an additional 0.125% if we draw upon greater than one-third of the facility amount and an additional 0.25% if we draw upon greater than two-thirds of the facility amount. The Eurocurrency loans bear interest at an adjusted rate based on LIBOR plus an adjustment percentage of from between 0.4% to 1.8% per annum, depending on NRG's senior debt credit rating and the amount outstanding under the facility. The facility terminates on March 9, 2001. The facility contains covenants that restrict the incurrence of liens and require us to maintain a net worth of at least $700 million plus 25% of our net income from January 1, 2000 through the determination date. In addition, we must maintain a debt to capitalization ratio of not more than 0.68 to 1.0 or not more than 0.72 to 1.0 for any consecutive two months in a six month period. An event of default under the Standby Letter of Credit Facility (described below) is also an event of default under this facility.

STANDBY LETTER OF CREDIT FACILITY

In November 1999, we entered into a $125 million standby letter of credit facility with Australia and New Zealand Banking Group Limited, as administrative agent. The facility is unsecured and provides for the issuances of letters of credit for our account with respect to financial and performance guarantees that we undertake. The facility terminates on November 30, 2002 unless extended in accordance with the terms of the facility. The facility contains covenants that restrict the incurrence of liens and require us to maintain a net worth to capitalization ratio of 0.32 to 1.0 for each fiscal quarter. In addition, the facility requires us to maintain a minimum net worth of at least $500 million plus 25% of our net income for each fiscal quarter beginning with the fiscal quarter ending September 30, 1999 for which net income is positive through the fiscal quarter ending on or ending last prior to the determination date.

SHARES ELIGIBLE FOR FUTURE SALE

Prior to this offering, there has been no public market for the common stock. We cannot provide any assurance that a significant public market for the common stock will develop or be sustained after this offering. Future sales of substantial amounts of common stock in the public market, or the possibility of such sales occurring, could adversely affect prevailing market prices for the common stock or our future ability to raise capital through an offering of equity securities.

After this offering, we will have outstanding 28,170,000 shares of common stock or 32,395,500 shares if the underwriters' over-allotment option is exercised in full. All of these shares will be freely tradable in the public market without restrictions under the Securities Act, except for any such shares acquired by an "affiliate" of NRG as that term is defined in Rule 144 under the Securities Act, which shares will remain subject to resale limitations of Rule 144.

Northern States Power will own 147,604,500 shares of class A common stock, which will represent approximately 84% of the total number of both common stock and class A common stock outstanding and which are immediately convertible into an equal number of shares of common stock upon the election of Northern States Power or upon a sale of shares of class A common stock to a third party. We have agreed, if so requested by Northern States Power, to file registration statements and take other steps to enable Northern States Power to sell shares of common stock held by it, including but not limited to shares of common stock acquired by conversion of shares of class A common stock. In addition, beginning 90 days after the date of this prospectus, Northern States Power will be entitled to make sales under Rule 144 of limited quantities of common stock. However, we and Northern States Power have agreed with the underwriters, subject to certain exceptions, not to sell any shares of common stock for a period of 180 days following the date of this prospectus.

Generally, Rule 144 provides that an affiliate may sell on the open market in brokers' transactions within any three month period a number of shares that does not exceed the greater of:

- 1% of the then outstanding shares of common stock; and

- the average weekly trading volume in the common stock on the open market during the four calendar weeks preceding the sale.

Sales under Rule 144 will also be subject to post-sale notice requirements and the availability of current public information about NRG.

Shares properly sold in reliance upon Rule 144 to persons who are not affiliates are freely tradable without restriction after the sale.

On January 1, 2001, the right to acquire approximately 692,000 shares of common stock underlying stock option grants will vest.

MATERIAL UNITED STATES TAX CONSEQUENCES TO NON-UNITED STATES HOLDERS

The following discussion is a summary of the material United States federal income and estate tax consequences of the ownership and disposition of our common stock to beneficial owners that are Non-United States persons. This discussion does not deal with all aspects of United States income and estate taxation and does not deal with foreign, state and local tax consequences that may be relevant to Non-United States persons in light of their personal circumstances. Furthermore, this discussion is based on the Internal Revenue Code of 1986, as amended, Treasury Department regulations, published positions of the Internal Revenue Service and court decisions now in effect, all of which are subject to change. YOU SHOULD CONSULT YOUR OWN TAX ADVISOR WITH REGARD TO THE APPLICATION OF THE FEDERAL INCOME TAX LAWS, AS WELL AS TO THE APPLICABILITY AND EFFECT OF ANY STATE, LOCAL OR FOREIGN TAX LAWS TO WHICH YOU MAY BE SUBJECT.

Under the Code, a "Non-United States person" means a person that is not any of the following:

- a citizen or resident of the United States;

- a corporation or partnership created or organized in or under the laws of the United States or any political subdivision of the United States;

- an estate the income of which is subject to United States federal income taxation regardless of its source; or

- a trust that:

  - is subject to the supervision of a court within the United States and the control of one or more United States persons; or

- has a valid election in effect under applicable United States Treasury regulations to be treated as a United States person.

DIVIDENDS

Generally, any dividend paid to a Non-United States person will be subject to United States withholding tax either at a rate of 30% of the gross amount of the dividend or at a lesser applicable treaty rate. However, dividends that are effectively connected with the conduct of a trade or business within the United States and, where a tax treaty applies, that are attributable to a United States permanent establishment are not subject to the withholding tax but instead are subject to United States federal income tax on a net income basis at applicable graduated individual or corporate rates.

Certain certification and disclosure requirements must be complied with in order to be exempt from withholding under the effectively connected income exemption. Any effectively connected dividends received by a foreign corporation may, under certain circumstances, be subject to an additional "branch profits tax" at a 30% rate or a lesser applicable treaty rate.

Until January 1, 2001, dividends paid to an address outside the United States are presumed to be paid to a resident of that country, unless the payer has knowledge to the contrary, for purposes of the withholding tax discussed above and, under the current interpretation of the United States Treasury regulations, for purposes of determining the applicability of a tax treaty rate. However, under United States Treasury regulations, if you wish to claim the benefit of an applicable treaty rate and avoid backup withholding, as discussed below, for dividends paid after December 31, 2000, you will be required to satisfy applicable certification and other requirements.

If you are eligible for a reduced treaty rate of United States withholding tax pursuant to an income tax treaty, you may obtain a refund of any excess amounts withheld by filing an appropriate claim for refund with the Internal Revenue Service.

GAIN ON DISPOSITION OF COMMON STOCK

If you are a Non-United States person, you will generally not be subject to United States federal income tax with respect to gain recognized on a sale or other disposition of our common stock unless:

- the gain is effectively connected with a trade or business in the United States and, where a tax treaty provides, the gain is attributable to a United States permanent establishment;

- if you are an individual and hold our common stock as a capital asset, you are present in the United States for 183 or more days in the taxable year of the sale or other disposition and certain other conditions are met;

- you are subject to tax pursuant to the provisions of the Code regarding taxation of certain U.S. expatriates; or

- we are or have been a "United States real property holding corporation" for United States federal income tax purposes.

We believe that we are not, and do not anticipate becoming, a "United States real property holding corporation" for United States federal income tax purposes. If we were to become a United States real property holding corporation, so long as our common stock continues to be regularly traded on an established securities market, you would be subject to federal income tax on any gain from the sale or other disposition of the stock only if you actually or constructively owned, during the five-year period preceding the disposition, more than 5% of our common stock.

Special rules may apply to certain Non-United States persons, such as "controlled foreign corporations," "passive foreign investment companies," "foreign personal holding companies" and corporations that accumulate earnings to avoid federal income tax, that are subject to special treatment under the Code. These entities should consult their own tax advisors to determine the United States federal, state, local and other tax consequences that may be relevant to them.

BACKUP WITHHOLDING AND INFORMATION REPORTING

We must report annually to the Internal Revenue Service and to you the amount of dividends paid to you and the tax withheld with respect to these dividends, regardless of whether withholding was required. Copies of the information returns reporting the dividends and withholding may also be made available to the tax authorities in the country in which you reside under the provisions of an applicable income tax treaty.

Under current law, backup withholding at the rate of 31% generally will not apply to dividends paid to you at an address outside the United States, unless the payer has knowledge that you are a United States person. Under the final regulations effective December 31, 2000, however, you will be subject to backup withholding unless applicable certification requirements are met.

Payment of the proceeds of a sale of our common stock within the United States or conducted through certain U.S. related financial intermediaries is subject to both backup withholding and information reporting unless you certify under penalties of perjury that you are a Non-United States person, and the payer does not have actual knowledge that you are a United States person, or you otherwise establish an exemption.

Any amounts withheld under the backup withholding rules may be allowed as a refund or a credit against your United States federal income tax liability provided the required information is furnished to the Internal Revenue Service.

ESTATE TAX

Common stock held by an individual Non-United States person at the time of death will be included in that holder's gross estate for United States federal estate tax purposes, unless an applicable estate tax treaty provides otherwise.

UNDERWRITING

Subject to the terms and conditions stated in the underwriting agreement dated the date hereof, each underwriter named below has severally agreed to purchase, and NRG Energy, Inc. has agreed to sell to such underwriter, the number of shares set forth opposite the name of such underwriter.

NAME	NUMBER OF SHARES
Salomon Smith Barney Inc.	10,148,000
Credit Suisse First Boston Corporation	5,074,000
ABN AMRO Incorporated	1,690,180
Banc of America Securities LLC	1,690,180
Goldman, Sachs & Co.	1,690,180
Lehman Brothers Inc.	1,690,180
Merrill Lynch, Pierce, Fenner & Smith Incorporated	1,690,180
Morgan Stanley & Co. Incorporated	1,690,180
Chatsworth Securities, LLC	350,865
CIBC World Markets Corp.	350,865
Dain Rauscher Incorporated	350,865
D.A. Davidson & Co.	350,865
A.G. Edwards & Sons, Inc.	350,865

U.S. Bancorp Piper Jaffray Inc.	350,865
Ragen Mackenzie Incorporated	350,865
The Robinson-Humphrey Company, LLC	350,865
Total	28,170,000

The underwriting agreement provides that the obligations of the several underwriters to purchase the shares included in this offering are subject to approval of certain legal matters by counsel and to certain other conditions. The underwriters are obligated to purchase all the shares (other than those covered by the over-allotment option described below) if they purchase any of the shares.

The underwriters, for whom Salomon Smith Barney Inc. and Credit Suisse First Boston Corporation, ABN AMRO Incorporated, Banc of America Securities LLC, Goldman, Sachs & Co., Lehman Brothers Inc., Merrill Lynch, Pierce Fenner & Smith Incorporated and Morgan Stanley & Co. Incorporated are acting as representatives, propose to offer some of the shares directly to the public at the public offering price set forth on the cover page of this prospectus and some of the shares to certain dealers at the public offering price less a concession not in excess of $0.54 per share. The underwriters may allow, and such dealers may reallow, a concession not in excess of $0.10 per share on sales to certain other dealers. If all of the shares are not sold at the initial offering price, the representatives may change the public offering price and the other selling terms.

We have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to 4,225,500 additional shares of common stock at the public offering price less the underwriting discount. The underwriters may exercise such option solely for the purpose of covering over-allotments, if any, in connection with this offering. To the extent such option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase a number of additional shares approximately proportionate to such underwriter's initial purchase commitment.

We, our officers and directors, and Northern States Power have agreed that, for a period of 180 days from the date of this prospectus, they will not, without the prior written consent of Salomon Smith Barney Inc., dispose of or hedge any shares of our common stock or any securities convertible into or exchangeable for common stock. Salomon Smith Barney Inc. in its sole discretion may release any of the securities subject to these lock-up agreements at any time without notice.

Prior to this offering, there has been no public market for the common stock. Consequently, the initial public offering price for the shares was determined by negotiations among us and the representatives. Among the factors considered in determining the initial public offering price were our record of operations, our current financial condition, our future prospects, our markets, the economic conditions in and future prospects for the industry in which we compete, our management, and currently prevailing general conditions in the equity securities markets, including current market valuations of publicly traded companies considered comparable to us. There can be no assurance, however, that the prices at which the shares will sell in the public market after this offering will not be lower than the price at which they are sold by the underwriters or that an active trading market in the common stock will develop and continue after this offering.

The common stock has been approved for listing on the NYSE under the symbol "NRG".

The following table shows the underwriting discounts and commissions to be paid to the underwriters by us in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase additional shares of common stock.

	PAID BY NRG	
	NO EXERCISE	FULL EXERCISE
Per share	$ 0.90	$ 0.90
Total	$25,353,000	$29,155,950

In connection with the offering, Salomon Smith Barney Inc., on behalf of the underwriters, may purchase and sell shares of common stock in the open market. These transactions may include over-allotment, syndicate covering transactions and stabilizing transactions. Over-allotment involves syndicate sales of common stock in excess of the number of shares to be purchased by the underwriters in the offering, which creates a syndicate short position. Syndicate covering transactions involve purchases of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions. Stabilizing transactions consist of certain bids or purchases of common stock made for the purpose of preventing or retarding a decline in the market price of the common stock while the offering is in progress.

The underwriters also may impose a penalty bid. Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when Salomon Smith Barney Inc., in covering syndicate short positions or making stabilizing purchases, repurchases shares originally sold by that syndicate member.

Any of these activities may cause the price of the common stock to be higher than the price that otherwise would exist in the open market in the absence of such transactions. These transactions may be effected on the NYSE or in the over-the-counter market, or otherwise and, if commenced, may be discontinued at any time.

We estimate that the total expenses of this offering will be $1,640,000.

The representatives have performed certain investment banking and advisory services for us from time to time for which they have received customary fees and expenses. The representatives may, from time to time, engage in transactions with and perform services for us in the ordinary course of their business.

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act of 1933, or to contribute to payments the underwriters may be required to make in respect of any of those liabilities.

Because an affiliate of Salomon Smith Barney Inc. is a party to the $300 million Citicorp USA loan with us, which will be repaid with the proceeds of this offering, this offering is being conducted in accordance with Rule 2710(c)(8) of the National Association of Securities Dealers, Inc. That rule requires that the initial public offering price may be no higher than that recommended by a "qualified independent underwriter", as defined by the NASD. Credit Suisse First Boston Corporation is serving in that capacity and has conducted due diligence and participated in the preparation of the registration

statement of which this prospectus forms a part. We will pay Credit Suisse First Boston Corporation $10,000 for serving as qualified independent underwriter. The initial public offering price will be no higher than that recommended by Credit Suisse First Boston Corporation.

At our request, certain of the underwriters have reserved up to 5% of the shares offered hereby (the "Directed Shares") for sale, at the initial public offering price, to some of our directors, officers and employees who have advised us of their desire to purchase such shares. The number of shares of our common stock available for sale to the general public will be reduced to the extent of sales of Directed Shares to any of the persons for whom they have been reserved. Any shares not so purchased will be offered by the underwriters on the same basis as all other shares of common stock offered hereby.

LEGAL MATTERS

The validity of the shares of common stock being offered will be passed on for NRG by Gibson, Dunn & Crutcher LLP. Certain legal matters will be passed on for the underwriters by Skadden, Arps, Slate, Meagher & Flom LLP. Skadden, Arps, Slate, Meagher & Flom LLP has from time to time represented us and may in the future, from time to time, represent us in connection with various matters.

EXPERTS

The consolidated financial statements of NRG Energy, Inc. and the carve-out financial statements of Cajun Electric as of December 31, 1999 and 1998 and for each of the three years in the period ended December 31, 1999 included in this prospectus have been so included in reliance on the reports of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

AVAILABLE INFORMATION

We have filed with the United States Securities and Exchange Commission a registration statement on Form S-1 under the Securities Act about the common stock that we are offering. This prospectus does not contain all of the information set forth in the registration statement and the exhibits and schedules to it. In addition, we currently file, and after the offering we will continue to file, annual, quarterly and special reports, proxy statements and other information with the Commission. For further information with respect to us, please refer to these documents on file, including the registration statement, and the exhibits and schedules thereto, which may be inspected without charge and copied at prescribed rates at the Commission's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the Commission at 1-800-SEC-0330. The Commission maintains a website that contains reports, proxy and information statements and other information filed electronically with the Commission at http://www.sec.gov.

INDEX TO NRG ENERGY, INC. FINANCIAL STATEMENTS

INDEX TO PRO-FORMA FINANCIAL STATEMENTS

CAJUN ELECTRIC (CAJUN FACILITIES)

INDEX TO CARVE-OUT FINANCIAL STATEMENTS

REPORT OF INDEPENDENT ACCOUNTANTS

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

In our opinion, the accompanying consolidated balance sheet and the related consolidated statement of income, of stockholder's equity and of cash flows present fairly, in all material respects, the financial position of NRG Energy, Inc. (a wholly-owned subsidiary of Northern States Power Company) and its subsidiaries at December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States. 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, 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 that our audits provide a reasonable basis for the opinion expressed above.

/s/ PRICEWATERHOUSECOOPERS LLP

March 17, 2000, except as to
Note 15 which is as of May 5, 2000.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF INCOME

	YEAR ENDED DECEMBER 31,			THREE MONTHS ENDED MARCH 31,	
	1997	1998	1999	1999	2000
	(IN THOUSANDS EXCEPT PER SHARE AMOUNTS)			(UNAUDITED)	
OPERATING REVENUES					
Revenues from wholly-owned operations...	$ 92,052	$100,424	$432,518	$ 37,847	$332,671
Equity in earnings of unconsolidated affiliates..........................	26,200	81,706	67,500	8,667	(9,644)
Total operating revenues and equity					

earnings	118,252	182,130	500,018	46,514	323,027
OPERATING COSTS AND EXPENSES					
Cost of wholly-owned operations	46,717	52,413	269,900	27,940	214,923
Depreciation and amortization	10,310	16,320	37,026	4,734	19,987
General, administrative and development	43,116	56,385	83,572	15,985	25,180
Total operating costs and expenses	100,143	125,118	390,498	48,659	260,090
OPERATING INCOME	18,109	57,012	109,520	(2,145)	62,937
OTHER INCOME (EXPENSE)					
Minority interest in earnings of consolidated subsidiary	(131)	(2,251)	(2,456)	(464)	(1,798)
Gain on sale of interest in projects	8,702	29,950	10,994	--	--
Write-off of project investments	(8,964)	(26,740)	--	--	--
Other income, net	11,764	8,420	6,432	734	1,531
Interest expense	(30,989)	(50,313)	(93,376)	(11,059)	(52,317)
Total other expense	(19,618)	(40,934)	(78,406)	(10,789)	(52,584)
INCOME (LOSS) BEFORE INCOME TAXES	(1,509)	16,078	31,114	(12,934)	10,353
INCOME TAX (BENEFIT) EXPENSE	(23,491)	(25,654)	(26,081)	(11,994)	1,607
NET INCOME	$ 21,982	$ 41,732	$ 57,195	$ (940)	$ 8,746
Earnings (loss) per share -- basic and diluted	$ .15	$ .28	$ .39	$ (.01)	$ .06
Weighted Average shares outstanding -- basic and diluted	147,605	147,605	147,605	147,605	147,605

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

	YEAR ENDED DECEMBER 31,			THREE MONTHS ENDED MARCH 31,	
	1997	1998	1999	1999	2000
			(IN THOUSANDS)		
				(UNAUDITED)	
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 21,982	$ 41,732	$ 57,195	$ (940)	$ 8,746
Adjustments to reconcile net income to net cash provided by operating activities					
Undistributed equity in earnings of unconsolidated affiliates	6,481	(23,391)	(27,181)	2,427	17,145
Depreciation and amortization	10,310	16,320	37,026	4,734	19,987
Deferred income taxes and investment tax credits	3,107	7,618	(3,401)	463	10,906
Minority interest	--	(5,019)	857	(534)	(1,694)
Investment write-downs	8,964	26,740	--	--	--
Gain on sale of investments	(8,702)	(29,950)	(10,994)	--	--
Cash provided (used) by changes in certain working capital items, net of effects from acquisitions and dispositions					
Accounts receivable	(2,859)	297	(99,608)	(1,645)	4,401
Accounts receivable-affiliates	(19,963)	21,657	9,964	(11,282)	--
Accrued income taxes	1,762	(24,861)	25,834	13,564	(13,793)
Inventory	(307)	(28)	(17,287)	(1,639)	10,450
Other current assets	305	469	(13,433)	746	(2,652)
Accrued property and sales taxes	1,645	(553)	1,740	1,798	2,175
Accounts payable-trade	7,791	(8,082)	40,616	5,375	28,778
Accounts payable-affiliates	--	--	--	--	(3,202)
Accrued salaries, benefits, and related costs	3,826	4,735	1,955	(2,440)	(4,106)
Accrued interest	1,215	1,050	5,192	1,471	20,289
Other current liabilities	6,084	(2,219)	(3,533)	(2,800)	(5,937)
Cash used by changes in other assets and liabilities	(7,155)	(4,517)	(16,322)	(1,641)	65,317
NET CASH (USED) PROVIDED BY OPERATING ACTIVITIES	34,486	21,998	(11,380)	7,657	156,810
CASH FLOWS FROM INVESTING ACTIVITIES					
Investments in projects	(318,149)	(132,379)	(107,260)	(16,267)	(17,933)
Acquisition, net of liabilities assumed	(148,830)	--	(1,519,365)	--	(1,723,158)
Consolidation of equity subsidiaries	--	--	20,181	--	--
Cash from sale of project investment	19,158	18,053	43,500	--	--
Decrease (increase) in notes receivable	(37,431)	16,858	58,331	18,438	293

Capital expenditures	(26,936)	(31,719)	(150,933)	(6,331)	(43,390)
(Increase) decrease in restricted cash	16,100	(2,433)	(13,067)	1,884	2,456
Other, net	10,114	--	--	--	--
NET CASH USED BY INVESTING ACTIVITIES	(485,974)	(131,620)	(1,668,613)	(2,276)	(1,781,732)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net borrowings under line of credit agreement	122,000	2,000	216,000	--	(36,000)
Capital contributions from parent	80,900	100,000	250,000	100,000	--
Proceeds from issuance of long-term debt	254,061	23,169	575,633	--	2,482,853
Proceeds from issuance of note	--	--	682,096	--	--
Principal payments on long-term debt	(5,925)	(21,152)	(18,634)	(99,294)	(715,491)
NET CASH PROVIDED BY FINANCING ACTIVITIES	451,036	104,017	1,705,095	706	1,731,362
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(452)	(5,605)	25,102	6,087	106,440
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	12,438	11,986	6,381	6,381	31,483
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 11,986	$ 6,381	$ 31,483	$ 12,468	$ 137,923
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION					
Interest paid (net of amount capitalized)	$ 30,890	$ 49,089	$ 82,891	$ 9,620	$ 32,028
Income taxes paid (benefits received), net	(24,577)	(6,797)	(54,384)	(23,060)	5,954

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	DECEMBER 31, 1998	DECEMBER 31, 1999	MARCH 31, 2000
	(IN THOUSANDS)		(UNAUDITED)
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 6,381	$ 31,483	$ 137,923
Restricted cash	4,021	17,441	14,985
Accounts receivable-trade, less allowance for doubtful accounts of $100, $186 and $1,392	15,223	126,376	146,030
Accounts receivable-affiliates	7,324	--	--
Taxes Receivable	21,169	--	7,819
Current portion of notes receivable -- affiliates	4,460	287	287
Current portion of notes receivable	26,200	--	--
Inventory	2,647	119,181	165,501
Prepayments and other current assets	4,533	29,202	31,854
Total current assets	91,958	323,970	504,399
PROPERTY, PLANT AND EQUIPMENT, AT ORIGINAL COST			
In service	291,558	2,078,804	3,759,856
Under construction	5,352	53,448	86,681
Total property, plant and equipment	296,910	2,132,252	3,846,537
Less accumulated depreciation	(92,181)	(156,849)	(176,883)
Net property, plant and equipment	204,729	1,975,403	3,669,654
OTHER ASSETS			
Investments in projects	800,924	932,591	893,303
Capitalized project costs	13,685	2,592	12,558
Notes receivable, less current portion -- affiliates	101,887	65,494	65,193
Notes receivable, less current portion	3,744	5,787	5,795
Intangible assets, net of accumulated amortization of $2,984, 4,308 and 4,828	22,507	55,586	56,072
Debt issuance costs, net of accumulated amortization of $1,675, $6,640 and $10,093	7,276	20,081	36,260
Other assets, net of accumulated amortization of $7,350, $8,909 and $9,444	46,716	50,180	50,574
Total other assets	996,739	1,132,311	1,119,755
TOTAL ASSETS	$1,293,426	$3,431,684	5,293,808

LIABILITIES AND STOCKHOLDER'S EQUITY

CURRENT LIABILITIES

Current portion of project level long-term debt	$ 8,258	$ 30,462	24,789
Revolving line of credit	--	340,000	304,000
Consolidated project level, non-recourse debt	--	35,766	--
Corporate level, recourse debt	--	--	300,000
Accounts payable-trade	7,371	61,211	115,837
Accounts payable-affiliate	--	6,404	3,202
Accrued income taxes	--	4,730	--
Accrued property and sales taxes	3,251	4,998	7,173
Accrued salaries, benefits and related costs	7,551	9,648	5,542
Accrued interest	7,648	13,479	33,768
Other current liabilities	8,289	17,657	12,996
Total current liabilities	42,368	524,355	807,307
OTHER LIABILITIES:			
Minority interest	13,516	14,373	12,679
Consolidated project-level, long-term, non-recourse debt	113,437	1,026,398	2,300,888
Corporate level long-term debt, less current portion	504,781	915,000	1,169,608
Deferred Income Taxes	19,841	16,940	27,910
Deferred Investment Tax Credits	1,343	1,088	1,024
Postretirement and other benefit obligations	11,060	24,613	38,373
Other long-term obligations and deferred income	7,748	15,263	63,899
Total liabilities	714,094	2,538,030	4,421,688
STOCKHOLDER'S EQUITY			
Class A common stock; $.01 par value; 250,000 shares authorized; 147,605 shares issued and outstanding	1,476	1,476	1,476
Additional paid-in capital	530,438	780,438	780,438
Retained earnings	130,015	187,210	195,956
Accumulated other comprehensive income (loss)	(82,597)	(75,470)	(105,750)
Total Stockholder's Equity	579,332	893,654	872,120
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$1,293,426	$3,431,684	$5,293,808

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDER'S EQUITY

	CLASS A COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS	ACCUMULATED OTHER COMPREHENSIVE INCOME	TOTAL STOCKHOLDER'S EQUITY
			(IN THOUSANDS)		
BALANCES AT DECEMBER 31, 1996	$1,476	$349,538	$ 66,301	$ 4,599	$421,914
Net Income			21,982		21,982
Currency translation adjustments				(74,098)	(74,098)
Comprehensive income for 1997					(52,116)
Capital contributions from parent		80,900			80,900
BALANCES AT DECEMBER 31, 1997	$1,476	$430,438	$ 88,283	$ (69,499)	$450,698
Net Income			41,732		41,732
Currency translation adjustments				(13,098)	(13,098)
Comprehensive income for 1998					28,634
Capital contributions from parent		100,000			100,000
BALANCES AT DECEMBER 31, 1998	$1,476	$530,438	$130,015	$ (82,597)	$579,332
Net Income			57,195		57,195
Currency translation adjustments				7,127	7,127
Comprehensive income for 1999					64,322
Capital contributions from parent		250,000			250,000
BALANCES AT DECEMBER 31, 1999	$1,476	$780,438	$187,210	$ (75,470)	$893,654
Net Income (unaudited)			8,746		8,746
Currency translation adjustments (unaudited)				(30,280)	(30,280)
Comprehensive income for 2000 (unaudited)					(21,534)
BALANCES AT MARCH 31, 2000 (UNAUDITED)	$1,476	$780,438	$195,956	$(105,750)	$872,120

Other comprehensive income is shown net of tax expenses (benefits) which were $0 during the three months ended March 31, 2000 (unaudited) and $0 during both 1999 and 1998 and $5.9 million in 1997.

See notes to consolidated financial statements.

NOTE 1 -- ORGANIZATION

NRG Energy, Inc. (the Company), a Delaware Corporation, was incorporated on May 29, 1992, as a wholly owned subsidiary of Northern States Power Company (NSP). Beginning in 1989, the Company was doing business through its predecessor companies, NRG Energy, Inc. and NRG Group, Inc., Minnesota corporations, which were merged into the Company subsequent to its incorporation. The Company and its subsidiaries and affiliates develop, build, acquire, own and operate non-regulated energy-related businesses.

NOTE 2 -- SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION AND BASIS OF PRESENTATION

The consolidated financial statements include the accounts of the Company and its subsidiaries (referred to collectively herein as the Company). All significant intercompany transactions and balances have been eliminated in consolidation. Accounting policies for all of the Company's operations are in accordance with accounting principles generally accepted in the United States. As discussed in Note 5, the Company has investments in partnerships, joint ventures and projects for which the equity method of accounting is applied. Earnings from equity in international investments are recorded net of foreign income taxes.

CASH EQUIVALENTS

Cash equivalents include highly liquid investments (primarily commercial paper) with a remaining 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 and funds held in trust accounts to satisfy the requirements of certain debt agreements.

INVENTORY

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

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are capitalized at original cost. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance 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

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 project is completed and considered operational. Capitalized interest is amortized using the straight line method over the useful life of the related project. Capitalized interest was $287,000 and $172,000 in 1999 and 1998, respectively.

DEVELOPMENT COSTS AND CAPITALIZED PROJECT COSTS

These costs include professional services, dedicated employee salaries, permits, and other costs which are incurred incidental to a particular project. Such costs are expensed as incurred until a sales agreement

or letter of intent is signed, and the project has been approved by the Company's Board of Directors. Additional costs incurred after this point are capitalized. When project operations begin, previously capitalized project costs are reclassified to investment in projects and amortized on a straight-line basis over the lesser of the life of the project's related assets or revenue contract period.

DEBT ISSUANCE COSTS

Costs to issue long-term debt have been capitalized and are being amortized over the terms of the related debt.

INTANGIBLES

Intangibles consist principally of the excess of the cost of investment in subsidiaries over the underlying fair value of the net assets acquired and are being amortized using the straight-line method over 20 to 30 years. The Company periodically evaluates the recovery of goodwill and other intangibles based on an analysis of estimated undiscounted future cash flows.

OTHER LONG TERM ASSETS

Other long-term assets consist primarily of service agreements and operating contracts. These assets are being amortized over the remaining terms of the individual contracts, which range from seven to twenty-eight years.

INCOME TAXES

The Company is included in the consolidated tax returns of NSP. The Company calculates its income tax provision on a separate return basis under a tax sharing agreement with NSP as discussed in Note 9. Current federal and state income taxes are payable to or receivable from NSP. The Company records income taxes using the liability method. Income taxes are deferred on all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by law to be in effect when the temporary differences reverse. The Company's policy for income taxes related to international operations is discussed in Note 9.

REVENUE RECOGNITION

Under fixed-price contracts, revenues are recognized as products or services are delivered. Revenues and related costs under cost reimbursable contract provisions are recorded as costs are incurred. Anticipated future losses on contracts are charged against income when identified.

FOREIGN CURRENCY TRANSLATION

The local currencies are generally the functional currency of the Company's foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. The resulting currency adjustments are accumulated and reported as a separate component of stockholder's equity. Income, expense, and cash flows are translated at weighted-average rates of exchange for the period.

DERIVATIVE FINANCIAL INSTRUMENTS

To preserve the U.S. dollar value of projected foreign currency cash flows, the Company hedges, or protects, those cash flows if appropriate foreign hedging instruments are available. The gains and losses on those agreements offset the effect of exchange rate fluctuations on the Company's known and anticipated cash flows. The Company defers gains on agreements that hedge firm commitments of cash flows, and accounts for them as part of the relevant foreign currency transaction when the transaction occurs. The Company defers expected losses on these agreements, unless it appears that the deferral would result in recognizing a loss later.

While the Company is not currently hedging investments involving foreign currency, the Company will hedge such investments when it believes that preserving the U.S. dollar value of the investment is appropriate. The Company is not hedging currency translation adjustments related to future operating results. The Company does not speculate in foreign currencies.

From time to time the Company also uses interest rate hedging instruments to protect it from an increase in the cost of borrowing. Gains and losses on interest rate hedging instruments are reported as part of the asset for Investments In Projects when the hedging instrument relates to a project that has financial statements that are not consolidated into the Company's financial statements. Otherwise, they are reported as part of debt.

USE OF ESTIMATES

The preparation of financial statements in conformity with Generally Accepted Accounting Principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

In recording transactions and balances resulting from business operations, the Company uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts and actuarially determined benefit costs, among others. 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 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities,". This statement requires that all derivatives be recognized at fair value in the balance sheet and that changes in fair value be recognized either currently in earnings or deferred as a component of Other Comprehensive Income, depending on the intended use of the derivative, its resulting designation and its effectiveness. The Company plans to adopt this standard in the first quarter of 2001, as required. The Company has not determined the potential impact of implementing this statement.

RECLASSIFICATIONS

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

INTERIM RESULTS (UNAUDITED)

Information for the three months ended March 31, 2000 and 1999 is unaudited. The information furnished in the unaudited March 31, 2000 and March 31, 1999 Statements of Income and Cash Flows include all adjustments, consisting only of normal recurring accruals, which are, in the opinion of management, necessary for a fair presentation of such financial statements. The data disclosed in these notes to the financial statements for this period is also unaudited.

NOTE 3 -- ASSET ACQUISITIONS AND DIVESTITURES

In February 1999, the Company purchased from Thermal Ventures, Inc. (TVI) the remaining 50.1% limited partnership interests held by TVI in San Francisco Thermal Limited Partnership and Pittsburgh Thermal Limited Partnership for $12.3 million. In April 1999, NRG acquired TVI's 50% member interest in North American Thermal Systems LLC (the entity holding the general partnership interest in the San Francisco and Pittsburgh partnerships) for $500,000.

In 1994, the Company, through a wholly-owned subsidiary, purchased a 50% ownership interest in Sunnyside Cogeneration Associates, a Utah joint venture, which owns and operates a 58 MW waste coal plant in Utah. The waste coal plant is currently being operated by a partnership that is 50% owned by a

Company affiliate. In March 1999, the Company and its partner executed an agreement to sell the Sunnyside project to an affiliate of Baltimore Gas & Electric for a purchase price of $2.0 million. There was no gain or loss on the sale which closed during the second quarter of 1999.

In April 1999, the Company completed the acquisition of the Somerset power station for approximately $55 million from the Eastern Utilities Association (EUA). The Somerset station, located in Somerset, Massachusetts, includes two coal-fired generating facilities and two aeroderivative combustion turbine peaking units with a capacity rating of 229 MW, of which 69 MW is on deactivated reserve. In connection with this acquisition, the Company entered into a Wholesale Standard Offer Service Agreement pursuant to which the Company is obligated to provide approximately 30% of the energy and capacity requirements of certain EUA affiliates (which is estimated to be approximately 275 MW at peak requirement) until December 31, 2009.

In May 1999, the Company and Dynegy Power Corporation (Dynegy), through West Coast Power LLC, completed the acquisition of the Encina generating station and 17 combustion turbines for approximately $356 million from San Diego Gas & Electric Company. The facilities, which have a combined capacity rating of 1,218 MW, are located near Carlsbad and San Diego, California. The Company and Dynegy each own a 50% interest in these facilities.

In June 1999, the Company completed its acquisition of the Huntley and Dunkirk generating stations from Niagara Mohawk Power Corporation (NIMO) for approximately $355 million. The two coal-fired power generation facilities are located near Buffalo, New York, and have a combined summer capacity rating of 1,360 MW. In connection with this acquisition, the Company entered into several Transition Power Purchase Agreements and a related swap agreement with NIMO pursuant to which NIMO purchases certain energy and capacity from these facilities for a term of four years.

In June 1999, the Company completed its acquisition of the Arthur Kill generating station and the Astoria gas turbine site from Consolidated Edison Company of New York, Inc. (ConEd) for approximately $505 million. These facilities, which are located in the New York City Area, have a combined capacity rating of 1,456 MW. In connection with the acquisition of each facility, the Company entered into (i) Transition Energy Sales Agreements pursuant to which energy from each facility is sold to ConEd for a transition period ending on the date on which the independent system operator in New York State (NYISO) commences operation (which commencement date was November 18, 1999) of a spot market for energy and certain ancillary services, and (ii) Transition Capacity Sales Agreements pursuant to which capacity from each facility is sold to ConEd for a transition period ending on the later of (a) the earlier of (i) December 31, 2002 or (ii) the date such facility receives notice from the NYISO that none of the electric generating capacity of such facility is required for meeting the installed capacity requirements in New York City, or (b) the date the NYISO commences an auction for system capacity. Pursuant to the

Transition Energy Sales Agreements, the Company agreed to sell to ConEd at a fixed price varying amounts of energy from the Arthur Kill generating facility and the Astoria gas turbine generating facility, in each case in amounts to be specified by ConEd, up to the full capability of each facility. Pursuant to the Transition Capacity Sales Agreements, the Company agreed to sell to ConEd at a fixed price, during certain periods, up to 100% of the capacity of the Arthur Kill generating facility and up to 100% of the capacity of the Astoria gas turbines facility.

In August 1999, the Company agreed to sell all but a 20 percent ownership interest in Cogeneration Corporation of America (CogenAmerica) to Calpine Corporation in connection with Calpine's acquisition of the remaining shares of CogenAmerica. Prior to December 1999, the Company owned approximately 45% of CogenAmerica. Upon closing of the transaction, all outstanding shares of CogenAmerica common stock (other than those retained by the Company) were acquired by Calpine for a cash purchase price of $25.00 per share. The transaction closed during the fourth quarter of 1999 and the Company retained a 20% ownership interest in CogenAmerica.

In October 1999, the Company completed its acquisition of the Oswego generating station from NIMO and Rochester Gas and Electric for approximately $85 million. The oil and gas-fired power generating facility which has a capacity rating of 1,700 MW, is located on a 93-acre site in Oswego, New

York. This facility consists of two units each having a capacity rating of 850 MW. In connection with this acquisition, the Company entered into a Transition Power Purchase Agreement with NIMO similar to those entered into in connection with the acquisitions of the Dunkirk and Huntley facilities. Pursuant to this agreement, the Company has agreed to sell 100% of the capacity of one unit, an option for up to 40% of the capacity of the other unit. The Company has agreed to sell NIMO an option to purchase a nominal amount of energy for a term of four years.

In December 1999, the Company acquired four fossil fuel generating stations and six remote gas turbines from CL&P for approximately $460 million, plus adjustments for working capital. These facilities are located throughout Connecticut and have a combined nominal capacity rating of 2,235 MW. The Company entered into a Standard Offer Service Wholesale Sales Agreement with CL&P pursuant to which the Company will supply CL&P with 35% of its standard offer service load during 2000, 40% during 2001 and 2002, and 45% during 2003. The Company estimates that 45% of CL&P's standard offer service load in 2003 will be approximately 2,070 MW at peak requirement. The Agreement terminates on December 31, 2003.

In December 1999, the Company purchased a 50% interest in the Rocky Road Power Plant, a 250 MW natural gas fired simple-cycle peaking facility in East Dundee, IL from Dynegy Inc., for approximately $60 million. The power plant began commercial operations on June 30, 1999 and received approval for the installation of an additional 100 MW natural gas combustion turbine in October 1999, increasing the facilities generating capacity to a nominal 350 MW. The expansion is expected to be in service before the start of the peak summer 2000 season.

Pro forma information has not been presented for the assets acquired in 1999 due to the fact that the assets acquired do not constitute businesses under Rule 11-01(d) of Regulation S-X. Accordingly, historical financial information does not exist for the assets acquired.

PRO FORMA RESULTS OF OPERATIONS -- CAJUN ACQUISITION (UNAUDITED)

During March 2000, the Company completed the acquisition of two fossil fueled generating plants from Cajun Electric Power Cooperative, Inc. for approximately $1.026 billion. The following information summarizes the pro forma results of operations as if the acquisition had occurred as of the beginning of the three-month period ended March 31, 2000. The pro forma information presented is for informational purposes only and is not necessarily indicative of future earnings or financial position or of what the earnings and financial position would have been had the acquisition of the Cajun Electric Facilities been consummated at the beginning of the respective periods or as of the date for which pro forma financial information is presented.

(In Thousands)	(Unaudited) Pro Forma 3 Months Ended March 31, 1999	March 31, 2000
OPERATING REVENUES		
Revenues from wholly-owned operations....................	$116,450	$412,653
Equity in earnings of unconsolidated affiliates..........	8,667	(9,644)
TOTAL OPERATING REVENUES..................................	125,117	403,009
Total operating costs and expenses........................	114,729	328,198
OPERATING INCOME..	10,388	74,811
Other income (expense)....................................	(28,885)	(70,375)
INCOME (LOSS) BEFORE INCOME TAXES.........................	(18,497)	4,436
Income tax (benefit) expense..............................	(14,296)	(841)
NET INCOME (LOSS)...	$ (4,201)	$ 5,277

NOTE 4 -- PROPERTY, PLANT AND EQUIPMENT

The major classes of property, plant and equipment at December 31 and March 31 were as follows:

	1998	1999	MARCH 31, 2000
	(THOUSANDS OF DOLLARS)		(UNAUDITED)
Facilities and equipment, including construction work in progress of $5,352, $53,448 and $86,681....................	$280,876	$2,056,621	$3,738,636
Land and improvements....................	10,397	64,330	79,606
Office furnishings and equipment..........	5,637	11,301	28,295
Total property, plant and equipment..........................	296,910	2,132,252	3,846,537
Accumulated depreciation..................	(92,181)	(156,849)	(176,883)
Net property, plant and equipment.........	$204,729	$1,975,403	$3,669,654

NOTE 5 -- INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

The Company 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 the Company 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 the Company's significant equity-method investments which were in operation at December 31, 1999 is as follows:

NAME	GEOGRAPHIC AREA	ECONOMIC INTEREST	PURCHASED OR PLACED IN SERVICE
Loy Yang A	Australia	25.37%	May 1997
Energy Developments Limited	Australia	29.14%	February 1997
ECK Generating	Czech Republic	44.50%	December 1994
MIBRAG mbH	Germany	33.33%	January 1994
Gladstone Power Station	Australia	37.50%	March 1994
Schkopau Power Station	Germany	20.95%	January and July 1996
Scudder Latin American Projects	Latin America	6.63%	June 1993
Long Beach Generating	USA	50.00%	April 1998
El Segundo Power	USA	50.00%	April 1998
Bolivian Power Company (Cobee)	Bolivia	49.10%	December 1996
Cogeneration Corp. of America	USA	20.00%	April 1996
Encina	USA	50.00%	May 1999
San Diego Combustion Turbines	USA	50.00%	May 1999

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:

	1997	1998	1999
	(THOUSANDS OF DOLLARS)		
Operating revenues	$1,612,897	$1,491,197	$1,732,521
Costs and expenses	1,522,727	1,346,569	1,531,958
Net income	$ 90,170	$ 144,628	$ 200,563

	1997	1998	1999
	(THOUSANDS OF DOLLARS)		
Current assets	$ 713,390	$ 710,159	$ 742,674
Noncurrent assets	7,733,886	7,938,841	7,322,219
Total assets	$8,447,276	$8,649,000	$8,064,893
Current liabilities	$ 472,980	$ 527,196	$ 708,114
Noncurrent liabilities	6,042,102	5,854,284	5,168,893
Equity	1,932,194	2,267,520	2,187,886
Total liabilities and equity	$8,447,276	$8,649,000	$8,064,893
NRG's share of equity	$ 694,655	$ 800,924	$ 932,591
NRG's share of income	$ 26,200	$ 81,706	$ 67,500

In accordance with FASB No. 121 "Accounting for Impairment of Long-lived Assets and for Long-lived Assets to be Disposed of," the Company reviews long lived assets, investments and certain intangibles for impairment whenever events or circumstances indicate the carrying amounts of an asset may not be recoverable. During 1998, the Company wrote down accumulated project development expenditures of $26.7 million. The Company's West Java, Indonesia, project totaling $22.0 million was written off due to the uncertainties surrounding infrastructure projects in Indonesia. Also during 1998, the Company wrote off its $1.9 million investment in the Sunnyside project and its $2.8 million investment in Alto Cachopoal. The charge represents the difference between the carrying amount of the investment and the fair value of the asset, determined using a cash flow model. In December 1997, the Company reviewed the carrying amount of the Sunnyside project that failed to restructure its debt and recorded a charge of $8.9 million. The charge represents the difference between the carrying amount of the investment and the fair value of the asset, determined using a discounted cash flow model.

NOTE 6 -- RELATED PARTY TRANSACTIONS

SALE TO AFFILIATE

During October 1998, the Company sold its interest in the Mid-Continent Power Corporation (MCPC) facility to CogenAmerica for a $2.1 million gain after elimination of affiliate interest. The MCPC facility is a 110 MW, gas-fired generation station located near Pryor, Oklahoma. The Company owns 20% of the outstanding stock of CogenAmerica.

OPERATING AGREEMENTS

The Company has two agreements with NSP for the purchase of thermal energy. Under the terms of the agreements, NSP charges the Company for certain costs (fuel, labor, plant maintenance, and auxiliary power) incurred by NSP to produce the thermal energy. The Company paid NSP $4.4 million in 1999 and $5.1 million in 1998 under these agreements. For the three months ended March 31, 2000 and 1999, the Company paid NSP $1.4 million and $1.1 million, respectively under these agreements (unaudited).

The Company has a renewable 10-year agreement with NSP, expiring on December 31, 2001, whereby NSP agrees to purchase refuse-derived fuel for use in certain of its boilers and the Company agrees to pay NSP a burn incentive. Under this agreement, the Company received $1.4 million and $1.4 million from NSP, and paid $2.7 million and $3.1 million to NSP in 1999 and 1998, respectively.

For the three months ended March 31, 2000 and 1999, the Company received $0.6 million and $0.6 million from NSP, respectively. For the three months ended March 31, 2000 and 1999, the Company paid $0.5 million and $0.5 million to NSP, respectively (unaudited).

ADMINISTRATIVE SERVICES AND OTHER COSTS

The Company and NSP have entered into an agreement to provide for the reimbursement of actual administrative services provided to each other, an allocation of NSP administrative costs and a working capital fee. Services provided by NSP to the Company are principally cash management, legal, accounting,

employee relations, benefits administration and engineering support. In addition, the Company employees participate in certain employee benefit plans of NSP as discussed in Note 10. During 1999 and 1998, the Company paid NSP $6.4 million and $5.2 million, respectively, as reimbursement under this agreement. For the three months ended March 31, 2000 and 1999, the Company paid NSP $2.0 million and $2.2 million, respectively (unaudited).

In 1996, the Company and NSP entered into an agreement for the Company to provide operations and maintenance services for NSP's Elk River resource recovery facility and Becker ash landfill. During 1999 and 1998, NSP paid the Company $1.9 million and $1.7 million, respectively, as compensation under this agreement. For the three months ended March 31, 2000 and 1999, NSP paid the Company $0.6 million and $0.6 million, respectively (unaudited).

NOTE 7 -- NOTES RECEIVABLE

Notes receivable consists primarily of fixed and variable rate notes secured by equity interests in partnerships and joint ventures. The notes receivable at December 31, and March 31 are as follows:

	1998	1999	MARCH 31, 2000
	(THOUSANDS OF DOLLARS)		(UNAUDITED)
COGENERATION CORPORATION OF AMERICA:			

Note due 2001, 9.5%	$ 2,539	$ --	$ --
Grays Ferry note due 2005, LIBOR plus 4.0% (9.31%@12/98)	1,900	--	--
Morris note due 2004, prime +3.5% (11.25%@12/98)	12,027	--	--
MCPC note due 2004, prime +3.5% (11.25%@12/98)	23,947	--	--
El Paso note, due January 1999, non interest bearing	26,200	--	--
Thermal Ventures, Inc. note due 1999, 11%	1,500	--	--
TOSLI, various notes due 2000, LIBOR plus 4.0% (10.0%@12/99)	132	207	207
Various secured notes due 2000 and later, non-interest and interest bearing	723	224	224
NEO notes to various affiliates due primarily 2012, prime +2% to 12.5%	27,445	26,850	26,548
Southern MN Prairieland Solid Waste, note due 2003, 7%	1,441	44	41
Pacific Generation, various notes, prime +2% to 12%	4,203	3,368	3,368
NRGenerating International BV notes to various affiliates, non-interest bearing	34,234	40,410	40,410
O'Brien Cogen II note, due 2008, non interest bearing	--	465	477
Total	$136,291	$71,568	$71,275

NOTE 8 -- LONG-TERM DEBT

Long-term debt consists of the following at December 31, and March 31:

	1998	1999	MARCH 31, 2000
	(THOUSANDS OF DOLLARS)		(UNAUDITED)
NEO Landfill Gas, Inc. term loan, due October 30, 2007, 9.35%	$ 9,847	$ --	$ --
NEO Landfill Gas Inc. construction loan due October 30, 2007 LIBOR +1% (6.31% @ 12/98)	6,550	--	--
NEO Landfill Gas, Inc. City of L.A. term loan, due December 2019 non-interest bearing	1,395	--	--
Revolving Line of Credit, due March 17, 2000, 5.85%	124,000	--	--
COBEE, due April 21, 2000, 0%	--	5,761	2,381
O'Brien Cogen II due August 31, 2000, 9.5%	--	2,893	2,893
NRG San Diego, Inc. promissory note, due June 25, 2003, 8.0%	2,141	1,729	1,621
Pittsburgh Thermal LP -- Credit Line, due 2004, LIBOR +4.25%	--	1,100	1,100
San Francisco Thermal LP -- Credit Line, due 2004, LIBOR +4.25%	--	900	900
Pittsburgh Thermal LP, due 2002-2004, 10.61%-10.73%	--	6,800	6,488
San Francisco Thermal LP, October 5, 2004, 10.61%	--	5,905	5,675
NRG Energy senior notes, due February 1, 2006, 7.625%	125,000	125,000	125,000
Note payable to NSP, due December 1, 1995-2006, 5.40%-6.75%	7,174	6,495	6,495
NRG Energy senior notes, due June 15, 2007, 7.50%	250,000	250,000	250,000
Camas Power Boiler LP, unsecured term loan, due June 30, 2007, 7.65%	17,576	17,087	15,726
Camas Power Boiler LP, revenue bonds, due August 1, 2007, 4.65%	11,010	9,130	9,625
Various NEO debt due 2005-2008, 9.35%	--	28,615	28,051
NRG Energy senior notes, due June 1, 2009, 7.50%	--	300,000	300,000
NRG Energy Center, Inc. senior secured notes due June 15, 2013, 7.31%	71,783	68,881	68,123
NRG Energy senior notes, due Nov. 1, 2013, 8.00%	--	240,000	240,000
Crockett Corp. LLP, due Dec. 31, 2014, 8.13%	--	255,000	252,643
NRG Northeast Generating debt	--	646,564	--
NRG Northeast Generating LLC, senior bonds, due Dec. 15, 2004, 8.065%	--	--	320,000
NRG Northeast Generating LLC, senior bonds, due June 15, 2015, 8.842%	--	--	130,000
NRG Northeast Generating LLC, senior bonds, due Dec. 15, 2024, 9.292%	--	--	300,000
NRG South Central Generating LLC, senior bonds, due March 15, 2016, 8.962%	--	--	500,000
NRG South Central Generating LLC, senior bonds, due Sept. 15, 2024, 9.479%	--	--	300,000
Sterling Luxembourg #3 Term Loan, due June 30, 2019, 7.86% -- Libor +1.31	--	--	373,956

NRG Energy ROARS, due March 15, 2005, 7.97%..........	--	--	254,608
	626,476	1,971,860	3,495,285
Less current maturities..............................	(8,258)	(30,462)	(24,789)
Total..	$ 618,218	$1,941,398	$3,470,496

The NRG Energy Center, Inc. notes are secured principally by long-term assets of the Minneapolis Energy Center (MEC). In accordance with the terms of the note agreement, MEC is required to maintain compliance with certain financial covenants primarily related to incurring debt, disposing of MEC assets, and affiliate transactions. MEC was in compliance with these covenants at December 31, 1999.

The note payable to NSP relates to long-term debt assumed by the Company in connection with the transfer of ownership of a Refuse Derived Fuel processing plant by NSP to the Company in 1993.

The NRG Energy $125 million, $250 million, $300 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 the ten-year senior notes mature in February 2006, June 2007, and 2009. The fourteen year notes mature in November 2013.

The $240 million of NRG Energy Senior notes due November 1, 2013 are remarketable or redeemable Security (ROARS). November 1, 2003 is the first remarketing date for these notes. Interest is payable semi-annually beginning May 1, 2000 through November 1, 2003, and then at intervals and interest rates as discussed in the indenture. On the remarketing date, the notes will either be mandatorily tendered to and purchased by Credit Suisse Financial Products or mandatorily redeemed by the Company at prices discussed in the indenture. The notes are unsecured debt that rank senior to all of the Company's existing and future subordinated indebtedness.

The NRG San Diego, Inc. promissory note is secured principally by long-term assets of the San Diego Power & Cooling Company.

The various NEO notes are term loans. The loans are secured principally by long-term assets of NEO Landfill Gas collection system. NEO Landfill Gas is required to maintain compliance with certain covenants primarily related to incurring debt, disposing of the NEO Landfill Gas assets, and affiliate transactions.

The Camas Power Boiler LP notes are secured principally by 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, 1999.

The Crockett Corporation term loan is secured by primarily the long-term assets of the Crockett Cogeneration project.

The O'Brien Cogen II promissory note is payable on the earlier of the first anniversary of the effective date (August 31, 1999) or upon the sale of the assets at the O'Brien Cogen II facility. Full payment of the note is guaranteed by the Company.

Annual maturities of long-term debt for the years ending after December 31, 1999 are as follows:

	(THOUSANDS OF DOLLARS)

2000	$ 30,462
2001	23,637
2002	26,104
2003	27,610
2004	31,594
Thereafter	1,832,453
Total	$1,971,860

The Company has $550 million in revolving credit facilities under a commitment fee arrangement. These facilities provide short-term financing in the form of bank loans and letters of credit. At December 31, 1999, the Company has $340 million outstanding under its revolving credit agreements.

The Company has a $500 million revolving credit facility under a commitment fee arrangement that matures in March 9, 2001. This facility provides short-term financing in the form of bank loans. At March 31, 2000, the Company had $304 million outstanding under this facility (Unaudited).

The Company had $116 million and $33.6 million in outstanding letters of credit as of December 31, 1999 and 1998, respectively.

In December 1999, the Company filed a shelf registration with the SEC to issue up to $500 million of unsecured debt securities. The Company expects to issue debt under this shelf during 2000 for general corporate purposes, which may include financing, development and construction of new facilities, additions to working capital and financing capital expenditures and pending or potential acquisitions.

On February 22, 2000, NRG Northeast Generating issued $750 million of 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 percent due in 2004, $130 million with an interest rate of 8.842 percent due in 2015 and $300 million with an interest rate of 9.292 percent due in 2024. The Company used $647 million of the proceeds to repay short-term borrowings outstanding at December 31, 1999; accordingly, $646.6 million of short term debt has been re-classified as long-term debt, based on this refinancing.

In March 2000, the Company issued $250 million of 8.70% 20-year remarketable or redeemable securities through an unconsolidated grantor trust. The funds were subsequently converted to 160 million pound sterling and will be used to finance the Company's investment in the Killingholme Power Station in England.

In March 2000, the Company issued L160 million (approximately $250 million at the time of issuance) of 7.97% reset senior notes due 2020, principally to finance our equity investment in the Killingholme facility. On March 15, 2005, these senior notes may be remarketed by Bank of America, N.A. at a fixed rate of interest through the maturity date or, at a floating rate of interest for up to one year and then at a fixed rate of interest through 2020. Interest is payable semi-annually on these securities beginning September 15, 2000 through March 15, 2005, and then at intervals and interest rates established in the remarketing possess (Unaudited).

In March 2000, three of the Company's foreign subsidiaries entered into a L335 million ($533 million) secured borrowing facility agreement with Bank of America International Limited, as arranger. Under this facility, the financial institutions have made available to our subsidiaries various term loans totaling L235 million ($374 million) for purposes of financing the acquisition of the Killingholme facility and L100 million ($159 million) of revolving credit and letter of credit facilities to provide working capital for operating the Killingholme facility. The final maturity date of the facility is the earlier of June 30, 2019, or the date on which all borrowings and commitments under the largest tranche of the term facility have been repaid or cancelled (Unaudited).

In March 2000, NRG South Central Generating LLC, a subsidiary of the Company, issued $800 million of senior secured bonds in a two tranches. 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. During March 2000, the proceeds were used to finance the Company's investment in the Cajun generating facilities (unaudited).

GUARANTEES

The Company may be 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. One example is the Company's guarantee of the obligations of its project subsidiary that operates the Gladstone facility for up to AUS$25 million, indexed to the Australian consumer price index, under the project subsidiary's operating and maintenance agreement with the owners of the facility. In addition, in connection with the purchase and sale of fuel, emission credits and power generation products to and from third parties with respect to the operation of some of the Company's generation facilities in the United States, the Company may be required to guarantee a portion of the obligations of certain of its subsidiaries. As of December 31, 1999, the Company's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries totaled approximately $416.4 million.

As of March 31, 2000, the Company's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries totaled approximately $504 million (unaudited).

NOTE 9 -- INCOME TAXES

The Company and its parent, NSP, have entered into a federal and state income tax sharing agreement relative to the filing of consolidated federal and state income tax returns. The agreement provides, among other things, that (1) if the Company, along with its subsidiaries, is in a taxable income position, the Company will be currently charged with an amount equivalent to its federal and state income tax computed as if the group had actually filed separate federal and state returns, and (2) if the Company, along with its subsidiaries, is in a tax loss position, the Company will be currently reimbursed to the extent its combined losses are utilized in a consolidated return, and (3) if the Company, along with its subsidiaries, generates tax credits, the Company will be currently reimbursed to the extent its tax credits are utilized in a consolidated return. The provision for income taxes consists of the following:

	1997	1998	1999
	(THOUSANDS OF DOLLARS)		
Current			
Federal	$ (8,516)	$(10,773)	$ 3,620
State	(1,274)	(3,940)	1,041
Foreign	236	2,358	4,040
	(9,554)	(12,355)	8,701
Deferred			
Foreign	(2,703)	(7,736)	(7,668)
Federal	(958)	8,828	(2,792)
State	(439)	1,541	(3,901)
	(4,100)	2,633	(14,361)
Tax credits recognized	(9,837)	(15,932)	(20,421)
Total income tax (benefit)	$(23,491)	$(25,654)	$(26,081)
Effective tax rate	(1,557)%	(160)%	(84)%

The components of the net deferred income tax liability at December 31 were:

	1998	1999
	(THOUSANDS OF DOLLARS)	
Deferred tax liabilities		
Differences between book and tax basis of property........	$29,712	$37,713
Investments in projects..................................	14,911	17,308
Goodwill...	978	1,117
Other..	6,212	5,544
Total deferred tax liabilities...........................	51,813	61,682
Deferred tax assets		
Deferred revenue...	1,402	841
Deferred compensation, accrued vacation and other reserves...	6,514	10,996
Development costs..	9,241	6,768
Deferred investment tax credits..........................	661	450
Steam capacity rights....................................	910	844
Foreign tax benefit......................................	12,425	20,919
Other..	819	3,924
Total deferred tax assets................................	31,972	44,742
Net deferred tax liability...............................	$19,841	$16,940

The effective income tax rate for the years 1999, 1998 and 1997 differs from the statutory federal income tax rate of 35% primarily due to state tax, foreign tax, and tax credits as shown above, income and expenses from foreign operations not subject to U.S. taxes (as discussed below).

The Company intends to reinvest the earnings of foreign operations except to the extent the earnings are subject to current U.S. income taxes. Accordingly, U.S. income taxes and foreign withholding taxes have not been provided on a cumulative amount of unremitted earnings of foreign subsidiaries of approximately $195 million and $158 million at December 31, 1999 and 1998. The additional U.S. income tax and foreign withholding tax on the unremitted foreign earnings, if repatriated, would be offset in whole or in part by foreign tax credits. Thus, it is not practicable to estimate the amount of tax that might be payable.

NOTE 10 -- BENEFIT PLANS AND OTHER POSTRETIREMENT BENEFITS

PENSION BENEFITS

The Company participates in NSP's noncontributory, defined benefit pension plan that covers substantially all employees, other then those employed as a result of the NE Generating asset acquisitions. Benefits are based on a combination of years of service, the employee's highest average pay for 48 consecutive months, and Social Security benefits. Plan assets principally consist of the common stock of public companies, corporate bonds and U.S. government securities. The Company's net annual periodic pension cost includes the following components:

COMPONENTS OF NET PERIODIC BENEFIT COST

	1997	1998	1999
	(THOUSANDS OF DOLLARS)		
Service cost benefits earned	$ 1,127	$ 1,303	$ 1,602
Interest cost on benefit obligation	1,187	1,417	1,739
Expected return on plan assets	(1,029)	(2,226)	(2,866)
Amortization of prior service cost	5	172	393
Recognized actuarial (gain) loss	(3)	(1,878)	(2,053)
Net periodic (benefit) cost	$ 1,287	$(1,212)	$(1,185)

The Company discontinued funding its pension costs in 1998 due to the effects of funding limitations from employee benefit and tax laws on NSP's plan. Plan assets consist principally of common stock of

public companies, corporate bonds and U.S. government securities. The funded status of the pension plan in which the Company employees participate is as follows at December 31:

RECONCILIATION OF FUNDED STATUS

	1998		1999	
	NSP PLAN	NRG PORTION	NSP PLAN	NRG PORTION
	(THOUSANDS OF DOLLARS)			
Benefit obligation at Jan. 1	$1,048,251	$17,410	$ 1,143,464	$ 20,112
Service cost	31,643	1,303	36,421	1,602
Interest cost	78,839	1,417	86,429	1,739
Plan amendments	102,315	3,045	184,255	2,214
Actuarial gain	(41,635)	(2,278)	(105,634)	(178)
Benefit payments	(75,949)	(785)	(97,086)	(1,200)
Benefit obligation at Dec. 31	$1,143,464	$20,112	$ 1,247,849	$ 24,289
Fair value of plan assets at Jan. 1	$1,978,538	$18,795	$ 2,221,819	39,079
Actual return on plan assets	319,230	21,069	293,904	9,199
Benefit payments	(75,949)	(785)	(97,086)	(1,200)
Fair value of plan assets at Dec. 31	$2,221,819	$39,079	$ 2,418,637	$ 47,078
Funded status at Dec. 31 -- excess of assets over obligation	$1,078,355	$18,967	$ 1,170,788	$ 22,789
Unrecognized transition (asset) obligation	(387)	--	(311)	--
Unrecognized prior service cost	114,305	2,954	277,350	4,775
Unrecognized net gain	(1,167,340)	(22,486)	(1,381,889)	(26,944)
Accrued (prepaid) benefit obligation at Dec. 31	$ 24,933	$ (565)	$ 65,938	$ 620

AMOUNT RECOGNIZED IN THE BALANCE SHEET

	1998		1999	
	NSP PLAN	NRG PORTION	NSP PLAN	NRG PORTION
	(THOUSANDS OF DOLLARS)			
Prepaid benefit cost	$24,933	$ --	$65,938	$ 868
Accrued benefit liability	--	(565)	--	(248)
Net amount recognized -- asset (liability)	$24,933	$(565)	$65,938	$ 620

The weighted average discount rate used in determining the actuarial present value of the projected benefit obligation was 7.5% for December 31, 1999 and 6.5% for December 31, 1998. The rate of increase in future compensation levels used in determining the actuarial present value of the projected obligation was 4.5% in 1999 and 4.5% in 1998. The assumed long-term rate of return on assets used for cost determinations was 8.5% for 1999 and 1998 and 9.0% for 1997.

Effective Jan. 1, 1998, NSP changed its method of accounting for subsidiary pension costs under SFAS No. 87. The new method, which now allocates plan assets based on subsidiary benefit obligations, was adopted to better match earnings on total plan assets with the corresponding subsidiary benefit obligations. The effect of this change decreased periodic pension costs by $2.9 million in 1998 from 1997 levels, including $1.3 million related to periods prior to the change. The effects of this change have not been reported separately on the income statement and prior periods have not been restated due to immateriality.

NRG EQUITY PLAN

Employees are eligible to participate in the Company's Equity Plan (the Plan). The Plan grants phantom equity units to employees based upon performance and job grade. The Company's equity units are valued based upon the Company's growth and financial performance. The primary financial measures used in determining the equity units' value are revenue growth, return on investment and cash flow from operations. The units are awarded to employees annually at the respective year's calculated share price (grant price). The Plan provides employees with a cash pay out for the unit's appreciation in value over the vesting period. The Plan has 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 1999 and 1998, the Company recorded approximately $13 million and $2.6 million, respectively for the Plan. During the three months ended March 31, 2000 and 1999, the Company recorded approximately $3.6 million and $0.8 million, respectively for the Plan (unaudited).

The Plan includes a change of control provision, which allow all shares to vest if the ownership of the Company were to change.

POSTRETIREMENT HEALTH CARE

The Company participates in NSP's contributory health and welfare benefit plan that provides health care and death benefits to substantially all employees after their retirement. The plan, was terminated for nonbargaining employees retiring after 1998 and for bargaining employees retiring after 1999. is intended to provide for sharing of costs of retiree health care between the Company and retirees. For covered retirees, the plan enables the Company to share the cost of retiree health costs. Nonbargaining retirees pay 40 percent of total health care costs. Cost-sharing for bargaining employees is governed by the terms of the collective bargaining agreement.

Postretirement health care benefits for the Company are determined and recorded under the provisions of SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." SFAS No. 106 requires the actuarially determined obligation for postretirement health care and death benefits to be fully accrued by the date employees attain full eligibility for such benefits, which is generally when they reach retirement age.

The Company's net annual periodic benefit cost under SFAS No. 106 includes the following components:

COMPONENTS OF NET PERIODIC BENEFIT COST

	1997	1998	1999

	(THOUSANDS OF DOLLARS)		
Service cost benefits earned	$223	$165	$ 9
Interest cost on benefit obligation	246	145	24
Amortization of transition asset	70	17	--
Amortization of prior service cost	--	(40)	(104)
Recognized actuarial (gain) loss	--	2	(34)
Net periodic (benefit) cost	$539	$289	$(105)

Plan assets as of December 31, 1999 consisted of investments in equity mutual funds and cash equivalents. The Company's funding policy is to contribute to NSP benefits actually paid under the plan.

The following table sets forth the funded status of the health care plan in which the Company employees participate at December 31:

RECONCILIATION OF FUNDED STATUS

	1998		1999	
	NSP PLAN	NRG PORTION	NSP PLAN	NRG PORTION
	(THOUSANDS OF DOLLARS)			
Benefit obligation at Jan. 1	$ 279,230	$ 3,893	$ 219,762	$ 1,517
Service cost	3,247	165	196	9
Interest cost	15,896	145	9,184	24
Plan amendments	(51,456)	(1,872)	(80,840)	(770)
Actuarial gain loss	(9,732)	(814)	8,269	(359)
Benefit payments	(17,423)	--	(16,637)	--
Benefit obligation at Dec. 31	$ 219,762	$ 1,517	$ 139,934	$ 421
Fair Value of plan assets at Jan. 1	$ 19,783	$ --	$ 34,514	$ --
Actual return on plan assets	2,471	--	3,982	--
Employer contributions	29,683	--	13,339	--
Benefit payments	(17,423)	--	(16,637)	--
Fair value of plan assets at Dec. 31	$ 34,514	$ --	$ 35,198	$ --
Funded status at Dec. 31 -- unfunded obligation	$ 185,248	$ 1,517	$(104,736)	$ (421)
Unrecognized transition obligation	(104,482)	--	22,073	--
Unrecognized prior service cost	2,399	786	(2,926)	(1,452)
Unrecognized net gain (loss)	(3,790)	237	10,580	(562)
Accrued (liability) benefit recorded at Dec. 31	$ 79,375	$ 2,540	$ (75,009)	$(2,435)

The assumed health care cost trend rates used in measuring the accumulated projected benefit obligation (APBO) at both December 31, 1999 and 1998, were 8.1% for those under age 65, and 6.1% for those over age 65. The assumed cost trends are expected to decrease each year until they reach 5.0% for both age groups in the year 2004, after which they are assumed to remain constant. A one percent increase in the assumed health care cost trend rate would increase the APBO by approximately $36 thousand as of December 31, 1999. Service and interest cost components of the net periodic postretirement cost would increase by approximately $2 thousand with a similar one percent increase in the assumed health care cost trend rate. The assumed discount rate used in determining the APBO was 6.5% for both December 31, 1999 and 1998, compounded annually. The assumed long-term rate of return on assets used for cost determinations under SFAS No. 106 was 8% for 1999, 1998 and 1997.

PENSION BENEFITS -- 1999 ACQUISITIONS

During 1999, the Company acquired several generating assets and assumed benefit obligations for a number of employees associated with those acquisitions. The plans assumed included noncontributory defined benefit pension formulas, matched 401(k) savings plans, and contributory post-retirement welfare plans. Approximately, 56% of the Company's benefit employees are represented by eight local labor unions under collective bargaining agreements, which expire between 2000 and 2003.

The Company sponsors one noncontributory, defined benefit pension plan that covers most of the employees associated with the 1999 acquisitions. Generally, the benefits are based on a combination of years of service, the final average pay and Social Security benefits.

COMPONENTS OF NET PERIODIC BENEFIT COST

	1999 (THOUSANDS OF DOLLARS)
Service cost benefits earned	$ 968
Interest cost on benefit obligation	1,115
Expected return on plan assets	(1,193)
Net periodic (benefit) cost	$ 890

RECONCILIATION OF FUNDED STATUS

	1999 (THOUSANDS OF DOLLARS)
Benefit obligation at beginning of period	$ 24,954
Additional Acquisitions during the Year	27,330
Service cost	968
Interest cost	1,115
Plan amendments	--
Actuarial gain	(1,098)
Benefit payments	(403)
Benefit obligation at Dec. 31	$ 52,866
Fair value of plan assets at beginning of period	$ 24,905
Additional assets transferred	10,070
Actual return on plan assets	3,091
Benefit payments	(403)
Fair value of plan assets at Dec. 31	$ 37,663
Funded status at Dec. 31 -- excess of assets over obligation	$(15,203)
Unrecognized transition (asset) obligation	--
Unrecognized prior service cost	--
Unrecognized net gain	(2,996)
(Accrued) Prepaid benefit obligation at Dec. 31	$(18,199)

AMOUNT RECOGNIZED IN THE BALANCE SHEET

	1999
	(THOUSANDS OF DOLLARS)
Prepaid benefit cost	--
Accrued benefit liability	$(18,199)
Net amount recognized -- (liability)	$(18,199)

The weighted average discount rate used in determining the actuarial present value of the projected benefit obligation was 7.5% for December 31, 1999. The rate of increase in future compensation levels used in determining the actuarial present value of the projected obligation was 4.5% for nonunion employees and 3.50% for union employees. The assumed long-term rate of return on assets used for cost determinations was 8.5% for 1999.

POSTRETIREMENT HEALTH CARE

The Company has also assumed post retirement health care benefits for some of the Company's employees associated with the 1999 acquisitions. The plan enables the Company and the retirees to share the costs of retiree health care. The cost sharing varies by acquisition group and collective bargaining agreements. There are no existing Company retirees under these plans as of December 31, 1999. Complete valuation data is not available for some of these groups. The estimated net periodic postretirement benefit cost for 1999 is $0.85 million. The estimated accumulated post retirement benefit obligation is $12 million at December 31, 1999.

401(K) PLANS

The Company also assumed several contributory, defined contribution employee savings plans as a result of its 1999 acquisition activity. These plans comply with Section 401(k) of the Internal Revenue Code and cover substantially all of the Company's employees who are not covered by NSP's 401(k) Plan. The Company matches specified amounts of employee contributions to the plan. Employer contributions made to the Company's plans were approximately $0.31 million in 1999.

NOTE 11 -- SALES TO SIGNIFICANT CUSTOMERS

During 1999, the Company's electric power generation operations located in the northeastern part of the United States, NRG Northeastern Generating LLC, accounted for approximately 60% of the Company's total revenues from wholly owned operations. Sales to three customers accounted for 10.5%, 21.0% and 19.7% of total revenues from wholly owned operations in 1999. During 1999, the Company entered into transition agreements with these customers providing for the sale of energy and other ancillary services generated from certain electric generating facilities recently acquired from these customers and others. These agreements generally range from four to ten years in duration.

The Company and the Ramsey/Washington Resource Recovery Project have a service agreement for waste disposal, which expires in 2006. Approximately 26.5% in 1998 of the Company's operating revenues were recognized under this contract. In addition, sales to one thermal customer amounted to 10.3% of operating revenues in 1998.

NOTE 12 -- FINANCIAL INSTRUMENTS

The estimated December 31 fair values of the Company's recorded financial instruments are as follows:

	1998		1999	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(THOUSANDS OF DOLLARS)			
Cash and cash equivalents	$ 6,381	$ 6,381	$ 31,483	$ 31,483
Restricted cash	4,021	4,021	17,441	17,441
Notes receivable, including current portion	136,291	136,291	71,568	71,568
Long-term debt, including current portion	502,476	519,418	1,971,860	1,931,969

For cash, 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

As of December 31, 1999, the Company had no contracts to hedge or protect foreign currency denominated future cash flows. One contract that was executed during 1999 had no material effect on earnings.

During the third quarter of 1999, NRG Northeast, a wholly owned subsidiary of the Company entered into $600 million of "treasury locks," at various interest rates, which expired in February 2000. These treasury locks were an interest rate hedge for an NRG Northeast bond offering that was completed on February 22, 2000. The proceeds of this bond offering were used to pay down borrowings under a NRG Northeast's existing short-term credit facility.

As of December 31, 1999, the Company had three interest rate swap agreements with notional amounts totaling approximately $393 million. The contracts are used to manage the Company's exposure to changes in interest rates. If the swaps had been discontinued on December 31, 1999, the Company would have owed the counterparties approximately $3 million. Management believes that the Company's exposure to credit risk due to nonperformance by the counterparties to its hedging contracts is insignificant, based on the investment grade rating of the counterparties. As of March 31, 2000, the Company had four interest rate swap agreements with notional amounts totaling approximately $692 million. If the swaps had been discontinued on March 31, 2000, the Company could have owed the Counterparties approximately $2 million (unaudited).

- In September 1999, the Company entered into a $200 million swap agreement effectively converting the 7.5 percent fixed rate on its senior notes to a variable rate based on the London Interbank Offered Rate. The swap expires on June 1, 2009.

- A second swap effectively converts a $16 million issue of variable rate debt into a fixed rate debt. The swap expires on September 30, 2002.

- A third swap converts $177 million of variable rate debt into fixed rate debt. The swap expires on December 17, 2014.

- A fourth swap converts L188 million of non-recourse variable rate debt into fixed rate debt. The swap expires on June 30, 2019 and is secured by the Killingholme assets (unaudited).

The Company's Power Marketing subsidiary uses energy forward contracts along with physical supply, to hedge market risk in the energy market. At December 31, 1999, the notional amount of energy forward contracts was approximately $207 million.

If the contracts had been terminated at December 31, 1999, the Company would have received approximately $12.0 million based on price fluctuations to date. Management believes the risk of counterparty nonperformance with regard to any of the Company's hedging transactions is not significant.

NOTE 13 -- COMMITMENTS AND CONTINGENCIES

OPERATING LEASE COMMITMENTS

The Company leases certain of its facilities and equipment under operating leases, some of which include escalation clauses, expiring on various dates through 2010. Rental expense under these operating leases was $5.4 million in 1999 and $1.7 million in 1998. Future minimum lease commitments under these leases for the years ending after December 31, 1999 are as follows:

	(THOUSANDS OF DOLLARS)
2000	$ 5,518
2001	5,223
2002	4,614
2003	4,161
2004	4,094
Thereafter	35,293
Total	$58,903

CAPITAL COMMITMENTS

The Company expects to invest approximately $2.7 billion in 2000, for nonregulated projects and property, including Cajun, Killingholme A and the Conectiv fossil assets.

CAPITAL COMMITMENTS -- INTERNATIONAL

In November 1999, the Company agreed to purchase the 665 MW Killingholme A station from National Power plc. Killingholme A was commissioned in 1994 and is a combined-cycle, gas-turbine power station located in England. The purchase price for the station will be approximately 410 million pounds sterling (approximately $662 million U.S. at end of year exchange rates), subject to commercial adjustments. The purchase price includes L20 million sterling (approximately $32 million U.S. at end of year exchange rates) that is contingent upon the successful completion of negotiations regarding NRG's purchase of National Power's Blyth generating facilities. The Blyth assets consist of two coal-fired stations totaling 1,140 MW of generation capacity located in England.

CAPITAL COMMITMENTS -- DOMESTIC

The Company, together with its partner and the creditors's committee filed a plan with the United States Bankruptcy Court for the Middle District of Louisiana to acquire 1,708 MW of fossil generating assets from Cajun Electric Power Cooperative of Baton Rouge, Louisiana (Cajun) for approximately $1.0 billion The consortium has the support of the Chapter 11 trustee and Cajun's secured creditors. During the third quarter of 1999, the U.S. Bankruptcy Judge confirmed the creditors plan of reorganization and the Company exercised an option to purchase its partner's 50% interest in the project. The Company expects to close the acquisition of the Cajun assets during the first quarter of 2000.

In January 2000, the Company agreed to purchase 1,875 MW of fossil-fueled electric generating capacity and other assets from Conectiv of Wilmington, Delaware for $800 million. The fossil-fueled generating facilities consist of

Conectiv's wholly owned BL England, Deepwater, Indian River and Vienna steam stations plus Conectiv's interest in the Conemaugh and Keystone steam stations. Other assets in the purchase are the 241-acre Dorchester site located in Dorchester County, Maryland, certain Merrill Creek Reservoir entitlements in Harmony Township, New Jersey and certain excess emission allowances.

In January 2000, the Company executed a memorandum of understanding with GE Power Systems, a division of General Electric Company, to purchase 11 gas turbine generators and five steam turbine generators. The purchase will take place over the next five years and is valued at approximately $500 million with an option to purchase additional units. The 16 turbines have an equivalent generation output of 3,000 MW and will be installed at the Company's existing North American plant sites.

In March 2000, the Company entered into an agreement with Great River Energy under which Great River assigned to the Company all of its rights and obligations with respect to two 135 MW turbines being built for it by Siemens Westinghouse. Our total cost for the turbines, which are scheduled for delivery in the first or second quarter of 2001, will be $43 million. The Company expects to install these turbines at either existing plant sites in the United States or new greenfield sites (unaudited).

In April 2000, the Company announced an agreement with Statoil Energy, Inc. to acquire Harrisburg Steam Works and Statoil Energy Power/Paxton L.P. (Statoil) located in Harrisburg, Pennsylvania for approximately $11 million. Harrisburg Steam Works provides steam to more than 300 residential, commercial and industrial customers, including the City of Harrisburg and the Commonwealth of Pennsylvania. Statoil is a cogeneration facility capable of supplying nearly 30% of the steam requirements for Harrisburg Steam Works and a chiller plant that serves the Harrisburg hospital. Statoil also operates a nationwide diesel engine service business (unaudited).

The Company has contractually agreed to the monetization of certain tax credits generated from landfill gas sales through the year 2007.

SOURCE OF CAPITAL

The Company anticipates funding its ongoing capital commitments through the issuance of debt, additional equity from NSP, and operating cash flows. In addition, the Company may issue a limited amount of equity financing to third parties for funding a portion of the capital requirements.

CONTINGENT REVENUES

During 1999, the first year of deregulation in the state of New York power industry, the Company has claims related to certain revenues earned during the period April 27, 1999 to December 31, 1999. The Company is actively pursuing resolution and/or collection of these amounts, which totaled approximately $8.9 million as of December 31, 1999. These amounts have not been recorded in the financial statements and will not be recognized as income until disputes are resolved and collection is assured. The contingent revenues relate to interpretation of certain transition power sales agreements and to sales to the NYPP and NEPOOL, conflicting meter readings, pricing of firm sales and other power pool reporting issues.

RETROACTIVE MARKET CAP (UNAUDITED)

On March 30, 2000 the Company received notification from the New York Independent System Operator (NYISO) of their petition to the Federal Energy Regulatory Commission (FERC) to place a $2.52 per megawatt hour market cap on ancillary service revenues. The NYISO also requested authority to impose this cap on a retroactive basis to March 1, 2000.

Noting that FERC orders have not, to date, adjusted rates retroactively to address market operations or market power concerns, in the context of an ISO or otherwise, our internal legal counsel have no reason to believe that NRG will not ultimately collect all of the amounts due from the NYISO for ancillary services provided in March 2000.

If the FERC authorizes the NYISO to impose the market cap on a retroactive basis, the Company would record a $8.2 million pretax reduction in earnings.

CONTRACTUAL COMMITMENTS

Arthur Kill Power and Astoria Power have entered into agreements with ConEd that obligate them to maintain the electric generating capability and availability of their respective facilities at specified levels for the terms of these agreements, and whereby during certain periods, ConEd will purchase specified amounts of capacity, as long as the capacity is counted in the installed capacity requirement for New York City. The capacity must satisfy all criteria, standards and requirements applicable to providers of installed capacity established by the New York State Reliability Counsel ("NYSRC"), the Northwest Power Coordinating Council ("NPCC"), the North American Electric Reliability Council ("NERC"), the New York Power Pool (NYPP) or the NYISO. Should the capacity of the facility drop below the minimum level required, the subsidiary owning the facility will pay to ConEd a deficiency charge. The sellers may use electric capacity other than that generated by their own plants to satisfy ConEd's demands.

The respective subsidiary will bill ConEd for the electricity capacity sold and ConEd will bill that subsidiary for any capacity deficiency payments on a monthly basis. Any amount unpaid after it is due will accrue interest. Any dispute on the amount payable will first be settled by good faith negotiation among the parties.

For the next four years, the Company estimates that a significant portion of the total revenues from the Dunkirk and Huntley facilities will be derived from four-year transition contracts for capacity and energy. All forward capacity is sold to NIMO during the transition period, with the remainder of energy sold to the NYISO. Each of the following agreements was executed on June 11, 1999 and extends for a term of four years.

To hedge its transition to market rates, NIMO has required NRG Power Marketing to enter into an International Swap Dealers Association (ISDA) Master Agreement (together with the Schedule, the Confirmation and the Guarantee Agreement, the "Swap Agreement"). Under the Swap Agreement, NIMO will pay to NRG Power Marketing a fixed monthly price for the Dunkirk (units 1, 2, 3 and 4) and Huntley (units 67 and 68 only) facilities' capacity and ancillary services and NRG Power Marketing will pay to NIMO the market rates for the related capacity and ancillary services. The swap is only a financial contract and it incorporates the terms of the ISDA Master Agreement.

NIMO will have the right from time to time to exercise a call option for an additional swap pursuant to which, within a certain limit consistent with outages and availability requirements, NIMO will nominate certain amounts of energy from the Dunkirk and Huntley facilities and will pay to NRG Power Marketing an amount for such energy determined in accordance with the heat rate curve representing the nominated unit. NRG Power Marketing will pay to NIMO the market rates for such energy at the time that the energy was nominated. However, NRG Power Marketing may refuse the call option for either of the facilities if a facility is unexpectedly forced off-line or derated sufficiently to be unable to fulfill the portion of the specified quantity of power in the option. Any such refusal of the call option will be limited to the Decline Quantity Cap, which is calculated based upon the capacity of the relevant facility for the prior six months. NIMO will be entitled to make up for any refused call option in the future by delivering reasonable notice to NRG Power Marketing.

In addition to the Swap Agreement, Huntley Power has entered into an agreement with NIMO that gives NIMO the option to purchase from the Huntley facility certain quantities of electricity generated by Huntley units 65 and 66, during the summer and winter months, up to a specified maximum limit for the term of this agreement. If Huntley Power is selling the electrical output generated by units 65 and 66 to a third party, Huntley Power may refuse to deliver such output to NIMO. Furthermore, if unit 65 or 66 is generating for NIMO, Huntley Power has the right to "recall" the unit(s) in order to facilitate a sale to a third party. If Huntley Power fails to meet NIMO's quantity request for electricity output, it will compensate NIMO. NIMO will pay Huntley Power according to the amount of electricity output delivered to NIMO, on a monthly basis. Control and title pass at the point of delivery of the energy and each party agrees to indemnify the other against any claims arising out of any act or incident occurring during the period when control and title of the electricity is vested in the indemnifying party.

Huntley Power has also entered into an agreement with NIMO that gives NIMO the option to purchase from Huntley Power certain quantities of electricity generated by Huntley units 67 or 68 (during peak and off-peak summer hours), within a specified range of MW per hour, not to exceed 189 MW for any one hour during the peak hours, for the term of the agreement. If Huntley Power fails to meet NIMO's quantity request for electricity, Huntley Power will compensate NIMO for quantities not provided. NIMO will pay Huntley Power according to the amount of power delivered to NIMO, on a monthly basis. Control and title passes at the point of delivery of the energy and each party shall indemnify the other party from any claims arising out of any act or incident occurring during the period when control and title of the electricity is vested in the indemnifying party.

Oswego Power has entered into a four-year transition power sales contract with NIMO in order to hedge its transition to market rates. Under the agreement, NIMO will pay to Oswego Power a fixed monthly price plus start up fees for the right, but not the obligation, to claim, at a specified delivery point or points, the installed capacity of unit 5 of the Oswego facility, and for the right to exercise, at a specified price, an option for an additional 350 MW of installed capacity. The total amount of energy which Oswego Power must supply under the call option is limited to a nominal amount of energy per year. Oswego Power may refuse such option if the facility is unexpectedly unavailable or derated sufficiently to be unable to fulfill the option, as long as Oswego Power uses "good utility practice" to maintain the power stations.

Oswego Power may also choose to supply the energy required from another source as long as adjustment is made for any difference in value between the agreed upon delivery point and the actual point of delivery. In the event that Oswego Power is unable to provide from its own sources installed capacity of unit 5 in the amount claimed by NIMO, Oswego Power must procure the capacity from the market and provide it to NIMO at no additional cost or else suffer a penalty.

NRG Power Marketing has entered into a Wholesale Standard Offer Service Agreement, dated October 13, 1998 and amended as of January 15, 1999 (the "WSO Agreement"), with Blackstone Valley Electric Company, Eastern Edison Company, and Newport Electric Corporation (collectively the "EUA Companies"), which obligates NRG Power Marketing to provide each of the EUA Companies with firm all-requirements electric service, including capacity, energy, reserves, losses and related services necessary to serve a specified share of the EUA Companies' aggregate load attributable to retail customers taking standard offer service. NRG Power Marketing assumes all expenses, liabilities and losses, regulatory or economical, related to such service. NRG Power Marketing may supply the power to the EUA Companies at any point on the New England Power Pool transmission facilities system or on the EUA Companies' system.

The price for each unit of electricity is a combination of a fixed price plus a fuel adjustment factor. The EUA Companies will calculate the estimated power supplied each month and pay to NRG Power Marketing the price for such electricity before the end of the next month. Any amounts unpaid by the due date will accrue interest. The EUA Companies may make retroactive adjustments to the bills for up to one year after the date of the original billing. NRG Power Marketing must meet certain creditworthiness criteria for the term of the agreement, or must provide a guaranty from an entity which meets the creditworthiness criteria. The term extends from April 26, 1999, the closing date of the asset purchase agreement until December 31, 2009. The agreement may also be terminated in the case of an event of default or if the facility's electric service requirement is less than 1 MW/hr for two consecutive months.

In 1999, the Company entered into a Standard Offer Service Wholesale Sales Agreement with CL&P. The Company will supply CL&P with 35 percent of its standard offer service load during 2000, 40 percent during 2001 and 2002, and 45 percent during 2003. The four year contract is valued at $1.7 billion. The Company will serve the load with a combination of existing generation and power purchases.

ENVIRONMENTAL REGULATIONS

Environmental controls at the federal, state, regional and local levels have a substantial impact on the Company's operations due to the cost of installation and operation of equipment required for compliance.

AIR

On October 12, 1999, the Company received a letter from the Office of the Attorney General of the State of New York speculating that based on a preliminary analysis, it believes that significant modifications were made to the Huntley and Dunkirk facilities during NIMO's ownership of these facilities without obtaining Prevention of Significant Deterioration (PSD) and/or New Source Review (NSR) permits. The letter requested documents related to historic maintenance, repair, and replacement work at the facilities, as well as other data related to operations and emissions from these facilities. On January 12, 2000, the Company received a formal request from the New York Department of Environmental Conservation (NYDEC) seeking essentially the same documents covered by the Attorney General's letter. The Company understands that the NYDEC request supercedes the Attorney General's request. Although the Company does not have knowledge that NIMO failed to comply with the preconstruction permit requirements at the Huntley and Dunkirk facilities, the Company has only recently initiated steps to investigate more fully allegations to the contrary. If it is determined that these facilities did not comply with the PSD or NSR permit programs, the Company could be required among other things, to install pollution control technology to further control the emissions of nitrogen oxide (NO(X)) and sulfur dioxide (SO(2)) from the Huntley and Dunkirk facilities. By virtue of conditions imposed under the

asset sale agreement between the Company and NIMO (the Company's rights and obligations under the asset sale agreement were substantially assigned to Huntley Power LLC and Dunkirk Power LLC), NIMO remains responsible for "any fines, penalties and assessments imposed by a governmental entity with respect to violation or alleged violation of Environmental Law which occurred prior to the Closing Date." Even so, the Company could become subject to fines and/or penalties associated with the period of time it has operated the facilities.

On October 14, 1999, Governor Pataki of New York directed the Commissioner of the NYDEC to require further reductions of SO(2) emissions and NO(X) emissions from New York power plants, beyond that which is required under current federal and state law. Under Governor Pataki's directive NO(X) emissions during the "non-ozone" season would be reduced to levels consistent with those currently mandated for the "ozone" season under the Ozone Transport Commission's Memorandum of Understanding. This additional reduction requirement would be phased in between January 1, 2003 and January 2, 2007. In addition, Governor Pataki announced that he is ordering a reduction of SO(2) emissions by 50% beyond the requirements of the Federal Acid Rain Program. These reductions would also be phased in between January 1, 2003 and January 1, 2007. Compliance with these emission reduction requirements, if they become effective, could have a material impact on the operation of the Company's facilities located in the State of New York.

On November 3, 1999, in the southern and mid-western regions of the United States, the United States Department of Justice (DOJ) filed suit against seven electric utilities for alleged violations of the Federal Clean Air Act (the Clean Air Act) NSR and PSD permit requirements at seventeen utility generating stations located in the southern and mid-western regions of the United States.

In addition, the United States Environmental Protection Agency (U.S. EPA) issued administrative notices of violation alleging similar violations at eight other power plants owned by certain of the electric utilities named as defendants in the DOJ lawsuit, and also issued an administrative order to the Tennessee Valley Authority for similar violations at seven of its power plants. The DOJ lawsuit alleges that the defendants, over a period of twenty years, undertook modifications at their generating stations that resulted in increased air emissions without complying with stringent regulatory requirements governing such modifications. Subsequent to the DOJ lawsuit, New York, Connecticut and New Jersey have brought their own lawsuits against American Electric Power, an Ohio based utility holding company, and have sought to intervene in the DOJ lawsuit. To date, no lawsuits or administrative actions have been brought against the Company or the former owners of the facilities alleging violations of the NSR or PSD requirements, although Atlantic City Electric Company has received information requests from the EPA regarding the Deepwater and B.L. England facilities. However, there is a likelihood that future lawsuits alleging similar violations may be filed against additional electric utility generating stations. The Company can provide no assurance that lawsuits or administrative actions alleging violations of PSD and NSR requirements will not be filed in the future.

The State of Connecticut has in the past considered, but rejected, legislation that would require older electrical generating stations to comply with more stringent pollution standards for NO(X) and SO(2) emissions. Currently, legislation is being debated in the Connecticut legislature that could require the Company's Connecticut facilities to rely on more expensive fuels or install additional air pollution control equipment. If such legislation were to become law without reflecting the benefit of critical elements of current federal emission reduction initiatives, such as market based emission trading between sources located across broad geographic regions, the Company's Connecticut facilities may be placed at a significant competitive disadvantage.

SITE CONTAMINATION/REMEDIATION

With the acquisition of the NRG Northeast assets, the Company assumed certain liabilities for existing environmental conditions at the sites with the exception of off-site liabilities associated with the disposal of hazardous materials and certain other environmental liabilities. The Company has not assumed responsibility for any contamination resulting from the September 7, 1998 explosion and subsequent fire involving a transformer containing PCBs at the Arthur Kill Station. The transformer explosion, fire and

subsequent oil spill resulted in the release of PCB's to the environment. Consolidated Edison Company of New York, Inc. maintains responsibility for the remediation of the PCB and other contamination associated with this event.

Environmental site assessments have been prepared for all of the recently acquired NRG Northeast assets. The remediation activities at the Arthur Kill, Astoria Gas Turbine and Somerset facilities are still in the study phase. As such, the remediation cost estimates are based on approaches that have not been approved yet by the regulatory agencies involved. Data from additional investigations performed at the Astoria Gas Turbines and the approach being taken at the Somerset Station may result in less costly remediation efforts than originally estimated.

For the Connecticut facilities, the Company is planning to conduct additional studies to better quantify remedial need. Such studies include the preparation of risk assessments to justify remedial actions proposed by the Company to the Connecticut Department of Environmental Protection and U.S. EPA.

COSTS

The Company has recorded approximately $5.8 million for expected environmental costs related to site remediation issues at the Arthur Kill, Astoria facilities and Somerset facilities. These amounts are based on the environmental assessments for these sites.

The Company has budgeted approximately $44 million for capital expenditures between 2000 and 2004 for environmental compliance, which includes the above remedial investigations, the installation of NO(X) control technology at the Somerset facility, intake screens at the Dunkirk facility, the resolution of consent orders for remediation at the Arthur Kill and Astoria facilities and the resolution of a consent order for water intake at the Arthur Kill facility.

CLAIMS AND LITIGATION

On or about July 12, 1999, Fortistar Capital Inc., a Delaware Corporation (Fortistar), filed a complaint in District Court (Fourth Judicial District, Hennepin County) in Minnesota against the Company, asserting claims for injunctive relief and for damages as a result of the Company's alleged breach of a confidentiality letter agreement with Fortistar relating to the Oswego facility (Letter Agreement).

The Company disputes Fortistar's allegations and has asserted numerous counterclaims.

A temporary injunction hearing was held on September 27, 1999. The acquisition of the Oswego facility was closed on October 22, 1999, following notification to the Court of Oswego Power's intention to close on that date. On January 14, 2000, the court denied Fortistar's request for a temporary injunction. The Company intends to continue to vigorously defend the suit and believes Fortistar's complaint to be without merit. No trial date has been set.

The Company is involved in various other litigation matters. The Company is actively defending these matters and does not feel the outcome of such matters would materially impact the Company's results of operations.

NOTE 14 -- SEGMENT REPORTING

The Company conducts its business within three segments: Independent Power Generation, Alternative Energy (Resource Recovery and Landfill Gas) and Thermal projects. These segments are distinct components of the Company 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 that have not been allocated to the operating segments.

	INDEPENDENT POWER GENERATION	ALTERNATIVE ENERGY	THERMAL	OTHER	TOTAL
			(THOUSANDS OF DOLLARS)		
MARCH 31, 2000 (UNAUDITED)					
OPERATING REVENUES					
Revenues from wholly-owned operations	$300,063	$ 7,017	$21,575	$ 3,716	$332,371
Intersegment Revenues	--	300	--	--	300
Equity in earnings of unconsolidated affiliates	(7,151)	(2,498)	5	--	(9,644)
Total operating revenues	292,912	4,819	21,580	3,716	323,027
OPERATING COSTS AND EXPENSES					
Cost of wholly-owned operations	194,375	6,795	12,232	1,521	214,923
Depreciation and amortization	15,300	1,710	2,865	112	19,987
General, administrative, and development	21,908	1,573	973	726	25,180
Total operating costs and expenses	231,583	10,078	16,070	2,359	260,090
OPERATING INCOME (LOSS)	61,329	(5,259)	5,510	1,357	62,937
OTHER INCOME (EXPENSE)					
Minority interest in earnings of consolidated subs	(1,798)	--	--	--	(1,798)
Other income, net	1,597	836	16	(918)	1,531
Interest expense	(29,797)	(653)	(2,105)	(19,762)	(52,317)
Total other income (expense)	(29,998)	183	(2,089)	(20,680)	(52,584)
INCOME (LOSS) BEFORE INCOME TAXES	31,331	(5,076)	3,421	(19,323)	10,353
INCOME TAX (BENEFIT)	5,651	(8,449)	1,418	2,987	1,607
NET INCOME (LOSS)	$ 25,680	$ 3,373	$ 2,003	$(22,310)	$ 8,746
MARCH 31, 1999 (UNAUDITED)					
OPERATING REVENUES					
Revenues from wholly-owned operations	$ 13,064	$ 6,280	$15,145	$ 3,034	$ 37,523
Intersegment revenues	--	324	--	--	324
Equity in earnings of unconsolidated affiliates	7,830	249	1,162	(574)	8,667

Total operating revenues	20,894	6,853	16,307	2,460	46,514
OPERATING COSTS AND EXPENSES					
Cost of wholly-owned operations	13,207	5,174	7,572	1,987	27,940
Depreciation and amortization	651	1,601	2,373	109	4,734
General, administrative, and development	12,737	1,399	688	1,161	15,985
Total operating costs and expenses	26,595	8,174	10,633	3,257	48,659
OPERATING INCOME (LOSS)	(5,701)	(1,321)	5,674	(797)	(2,145)
OTHER INCOME (EXPENSE)					
Minority interest in earnings of consolidated subs	(464)	--	--	--	(464)
Other income, net	1,512	290	9	(1,077)	734
Interest expense	(6,722)	(488)	(1,784)	(2,065)	(11,059)
Total other income (expense)	(5,674)	(198)	(1,775)	(3,142)	(10,789)
INCOME (LOSS) BEFORE INCOME TAXES	(11,375)	(1,519)	3,899	(3,939)	(12,934)
INCOME TAX (BENEFIT)	(12,324)	(5,032)	1,736	3,626	(11,994)
NET INCOME (LOSS)	$ 949	$ 3,513	$ 2,163	$ (7,565)	$ (940)

	INDEPENDENT POWER GENERATION	ALTERNATIVE ENERGY	THERMAL	OTHER	TOTAL
		(THOUSANDS OF DOLLARS)			
1999					
OPERATING REVENUES					
Revenues from wholly-owned operations(a)	$322,943	$ 26,934	$76,277	$ 5,401	$431,555
Intersegment revenues	--	963	--	--	963
Equity in earnings of unconsolidated affiliates(b)	69,686	(2,205)	19	--	67,500
Total operating revenues	392,629	25,692	76,296	5,401	500,018
OPERATING COSTS AND EXPENSES					
Cost of wholly-owned operations	207,081	24,977	42,401	(4,559)	269,900
Depreciation and amortization	17,153	6,126	6,280	7,467	37,026
General, administrative, and development	33,783	7,876	8,869	33,044	83,572
Total operating costs and expenses	258,017	38,979	57,550	35,952	390,498
OPERATING INCOME (LOSS)	134,612	(13,287)	18,746	(30,551)	109,520
OTHER INCOME (EXPENSE)					
Minority interest in earnings of consolidated Subsidiary	(2,322)	--	(134)	--	(2,456)
Write-off of investment	--	--	--	--	--
Gain on sale of interest in projects	--	--	--	10,994	10,994
Other income, net	2,328	(4,281)	10	8,375	6,432
Interest expense	(25,918)	169	(8,152)	(59,475)	(93,376)
Total other income (expense)	(25,912)	(4,112)	(8,276)	(40,106)	(78,406)
INCOME (LOSS) BEFORE INCOME TAXES	108,700	(17,399)	10,470	(70,657)	31,114
INCOME TAX (BENEFIT)	8,812	(27,642)	3,963	(11,214)	(26,081)
NET INCOME (LOSS)	$ 99,888	$ 10,243	$ 6,507	$(59,443)	$ 57,195
1998					
OPERATING REVENUES					
Revenues from wholly-owned operations(a)	$ 8,185	$ 30,143	$52,699	$ 7,660	$ 98,687
Intersegment revenues	--	1,737	--	--	1,737
Equity in earnings of unconsolidated affiliates(b)	81,948	(1,314)	1,215	(143)	81,706
Total operating revenues	90,133	30,566	53,914	7,517	182,130
OPERATING COSTS AND EXPENSES					
Cost of wholly-owned operations	7,097	20,980	24,665	(329)	52,413
Depreciation and amortization	980	5,590	9,258	492	16,320
General, administrative, and development	(7,099)	7,776	3,298	52,410	56,385
Total operating costs and expenses	978	34,346	37,221	52,573	125,118
OPERATING INCOME (LOSS)	89,155	(3,780)	16,693	(45,056)	57,012
OTHER INCOME (EXPENSE)					
Minority interest in earnings of consolidated Subsidiary	(2,251)	--	--	--	(2,251)
Write-off of investment	(26,740)	--	--	--	(26,740)
Gain on sale of interest in projects	29,950	--	--	--	29,950
Other income, net	2,482	2,683	118	3,137	8,420
Interest expense	(586)	(1,921)	(7,359)	(40,447)	(50,313)
Total other income (expense)	2,855	762	(7,241)	(37,310)	(40,934)
INCOME (LOSS) BEFORE INCOME TAXES	92,010	(3,018)	9,452	(82,366)	16,078
INCOME TAX (BENEFIT)	18,605	(16,445)	2,852	(30,666)	(25,654)
NET INCOME (LOSS)	$ 73,405	$ 13,427	$ 6,600	$(51,700)	$ 41,732

	INDEPENDENT POWER GENERATION	ALTERNATIVE ENERGY	THERMAL	OTHER	TOTAL
	(THOUSANDS OF DOLLARS)				
1997					
OPERATING REVENUES					
Revenues from wholly-owned operations(a)..........	$ 5,339	$ 27,257	$48,604	$ 9,926	$ 91,126
Intersegment revenues.............................	--	926	--	--	926
Equity in earnings of unconsolidated affiliates(b)..................................	26,206	(192)	186	--	26,200
Total operating revenues...................	31,545	27,991	48,790	9,926	118,252
OPERATING COSTS AND EXPENSES					
Cost of wholly-owned operations...................	1,693	17,730	24,902	2,392	46,717
Depreciation and amortization.....................	483	2,842	6,623	362	10,310
General, administrative, and development..........	8,186	6,111	2,403	26,416	43,116
Total operating costs and expenses.........	10,362	26,683	33,928	29,170	100,143
OPERATING INCOME (LOSS)............................	21,183	1,308	14,862	(19,244)	18,109
OTHER INCOME (EXPENSE)					
Minority interest in earnings of consolidated Subsidiary......................................	(131)				(131)
Write-off of investment...........................	(8,964)				(8,964)
Gain on sale of interest in projects..............	1,559			7,143	8,702
Other income, net.................................	5,888	2,618	(14)	3,272	11,764
Interest expense..................................	(653)	(529)	(5,958)	(23,849)	(30,989)
Total other income (expense)...............	(2,301)	2,089	(5,972)	(13,434)	(19,618)
INCOME (LOSS) BEFORE INCOME TAXES..................	18,882	3,397	8,890	(32,678)	(1,509)
INCOME TAX (BENEFIT)...............................	(6,502)	(4,888)	3,165	(15,266)	(23,491)
NET INCOME (LOSS)..................................	$ 25,384	$ 8,285	$ 5,725	$(17,412)	$ 21,982

(a) Revenues from wholly-owned operations are from external customers located in the United States.

(b) The Company has significant equity investments for non-regulated projects outside of the United States. Equity earnings of unconsolidated affiliates, primarily independent power projects, includes $33.5 million in 1999, $29.3 million in 1998 and $27.1 million in 1997 from non-regulated projects located outside of the United States. The Company's equity investments in projects outside of the United States were $602.4 million in 1999, $591 million in 1998 and $517 million in 1997.

NOTE 15 -- SUBSEQUENT EVENT

On May 5, 2000 the Board of Directors approved a conversion of the 1,000 shares of common stock outstanding into 147,604,500 shares of Class A common stock, par value $.01. In addition, the Company authorized a total of 250,000,000 shares of Class A common stock, par value $.01, 550,000,000 shares of common stock, par value $.01, and 200,000,000 shares of preferred stock. Class A common stock has identical rights to common stock except it has ten votes per share. All share and per share data included in the financial statements have been restated to reflect this exchange and reclassification.

NRG ENERGY, INC.

INTRODUCTION TO PRO FORMA FINANCIAL STATEMENTS

On March 31, 2000, Louisiana Generating LLC (Louisiana Generating), a wholly-owned subsidiary of NRG Energy, Inc. (NRG) completed the purchase of 1,708 megawatts (MW) of fossil fuel generating assets from Cajun Electric Power Cooperative, Inc. (Cajun) for approximately $1.026 billion. The purchase price was funded through an $800 million bond offering and an equity contribution from NRG.

The Cajun assets consist of two plants near New Roads, Louisiana, a two-unit, 220 MW gas-turbine generating station and a three-unit 1,488 MW coal fired generating station.

Louisiana Generating was formed for the purpose of facilitating the acquisition of the Cajun facilities and will own, operate and maintain the Cajun facilities.

The purchase price of $1.026 billion has been preliminarily allocated to tangible assets, identifiable assets and intangible assets of Louisiana Generating based on estimates of their respective values and an initial review of an appraisal recently completed. This appraisal needs to be carefully evaluated and will most likely be adjusted for other valuations and studies currently underway. These evaluations and studies will be completed over the next several months and, as such, final values may differ substantially from those shown.

The pro forma combined financial statements should be read in conjunction with NRG's and the Cajun Electric (carve-out) historical financial statements. The following pro forma income statement for the three months ended March 31, 2000 and the year ended December 31, 1999 presents the combination of NRG and the Cajun Electric facilities as if the acquisition occurred on January 1, 2000 and January 1, 1999, respectively. The pro forma balance sheet presents the combination of NRG and the Cajun Electric facilities as if the acquisition occurred on December 31, 1999. The pro forma information presented is for informational purposes only and is not necessarily indicative of future earnings or financial position or of what the earnings and financial position would have been had the acquisition of the Cajun Electric facilities been consummated at the beginning of the respective periods or as of the date for which pro forma financial information is presented.

NRG ENERGY, INC.
PRO FORMA INCOME STATEMENT
THREE MONTHS ENDED MARCH 31, 2000
(THOUSANDS OF DOLLARS)
(UNAUDITED)

	NRG ENERGY, INC.	CAJUN ELECTRIC (CAJUN FACILITIES)	PRO FORMA ADJUSTMENTS DEBIT	PRO FORMA ADJUSTMENTS CREDIT	NRG ENERGY, INC. PRO FORMA
OPERATING REVENUES					
Revenues from wholly-owned operations	$332,671	$79,982	$ --	$ --	$412,653
Equity in earnings of unconsolidated affiliates	(9,644)				(9,644)
Total operating revenues	323,027	79,982	--	--	403,009
OPERATING COSTS AND EXPENSES					
Cost of wholly-owned operations	214,923	58,628			273,551
Depreciation and amortization	19,987	9,647		2,590(1)	27,044
General, administrative and development	25,180	2,423			27,603
Total Operating costs and expenses	260,090	70,698	--	2,590	328,198
OPERATING INCOME	62,937	9,284	--	2,590	74,811
OTHER INCOME (EXPENSE)					
Minority interest in earnings of consolidated subsidiary	(1,798)				(1,798)
Other income, net	1,531	521			2,052
Interest expense	(52,317)		18,312(2)		(70,629)
Total other expense	(52,584)	521	18,312	--	(70,375)
INCOME (LOSS) BEFORE INCOME TAXES	10,353	9,805	18,312	2,590	4,436
INCOME TAX EXPENSE (BENEFIT)	1,607	--	--	(2,448)(3)	(841)

NET INCOME (LOSS)	$ 8,746	$ 9,805	$18,312	$ 5,038	$ 5,277

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(1) Reflects lower net depreciation/amortization resulting from assets and capitalized costs being depreciated over a longer estimated useful life based on engineering studies.

(2) Reflects accrued interest on $800 million principal amount for 3 months at a rate of 9.156% per annum.

(3) Incremental tax expense (benefit) is shown based on a rate of 41.37%.

NRG ENERGY, INC.

PRO FORMA BALANCE SHEET
DECEMBER 31, 1999
(THOUSANDS OF DOLLARS)
(UNAUDITED)

	NRG ENERGY, INC.	CAJUN ELECTRIC (CAJUN FACILITIES)	PRO FORMA ADJUSTMENTS DEBIT	PRO FORMA ADJUSTMENTS CREDIT	NRG ENERGY, INC. PRO FORMA
ASSETS					
CURRENT ASSETS					
Cash and cash equivalents	$ 31,483	$ --	$ --	$ --	$ 31,483
Restricted cash	17,441				17,441
Accounts receivable-trade, less allowance for doubtful accounts of $186	126,376	33,842			160,218
Accounts receivable-affiliates	--				--
Taxes receivable	--				--
Current portion of notes receivable-affiliates	287				287
Current portion of notes receivable	--				--
Inventory	119,181	34,234			153,415
Prepayments and other current assets	29,202	1,600			30,802
Total current assets	323,970	69,676	--	--	393,646
PROPERTY PLANT AND EQUIPMENT, AT ORIGINAL COST					
In service	2,078,804	1,208,832	451,647(A)		3,739,283
Under construction	53,448	3,996			57,444
Total property, plant and equipment	2,132,252	1,212,828	451,647	--	3,796,727
Less accumulated depreciation	(156,849)	(632,899)			(789,748)
Net property, plant and equipment	1,975,403	579,929	451,647	--	3,006,979
OTHER ASSETS					
Investments in projects	932,591				932,591
Capitalized project costs	2,592				2,592
Notes receivable, less current portion-affiliates	65,494				65,494
Notes receivable, less current portion	5,787				5,787
Intangible assets, net of accumulated amortization of $4,308	55,586				55,586
Debt issuance costs, net of accumulated amortization of $6,640	20,081				20,081
Other assets, net of accumulated amortization of					

$8,909	50,180	4,188			54,368
Total other assets	1,132,311	4,188	--	--	1,136,499
TOTAL ASSETS	$3,431,684	$ 653,793	$ 451,647	$ --	$4,537,124

	NRG ENERGY, INC.	CAJUN ELECTRIC (CAJUN FACILITIES)	PRO FORMA ADJUSTMENTS DEBIT	PRO FORMA ADJUSTMENTS CREDIT	NRG ENERGY, INC. PRO FORMA
LIABILITIES AND STOCKHOLDER'S EQUITY					
CURRENT LIABILITIES					
Current portion of project level long-term debt	$ 30,462	$ --	$ --	$ --	$ 30,462
Revolving line of credit and other short term debt	340,000			288,000(D)	628,000
Consolidated project level, non recourse debt	35,766				35,766
Accounts payable-trade	61,211	4,806			66,017
Accounts payable-affiliate	6,404				6,404
Accrued income taxes	4,730				4,730
Accrued property and sales taxes	4,998	150			5,148
Accrued salaries, benefits and related costs	9,648				9,648
Accrued interest	13,479				13,479
Other current liabilities	17,657	8,966			26,623
Total current liabilities	524,355	13,922	--	288,000	826,277
OTHER LIABILITIES					
Minority Interest	14,373				14,373
Consolidated project level, long-term, non recourse debt	1,026,398			800,000(B)	1,826,398
Corporate level long-term debt, less current portion	915,000				915,000
Deferred income taxes	16,940				16,940
Deferred investment tax credits	1,088				1,088
Postretirement and other benefit obligations	24,613				24,613
Other long-term obligations and deferred income	15,263	3,518			18,781
Total liabilities	2,538,030	17,440	--	1,088,000	3,643,470
STOCKHOLDER'S EQUITY					
Class A common stock; $.01 par value; 250,000 shares authorized; 147,605 shares issued and outstanding	1,476				1,476
Additional paid-in capital	780,438	636,353	636,353(C)		780,438
Retained earnings	187,210				187,210
Accumulated other comprehensive income	(75,470)				(75,470)
Total Stockholder's equity	893,654	636,353	636,353	--	893,654
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$3,431,684	653,793	$ 636,353	$1,088,000	$4,537,124

FOOTNOTES

(A) Reflects increase in overall fixed asset balances resulting from purchase accounting adjustments net of depreciation expense.

(B) Reflects $800 million debt from issuance of bonds.

(C) Reflects elimination of Cajun Electric equity.

(D) Reflects short-term borrowings used to fund the acquisition of the Cajun facilities.

NRG ENERGY, INC.

PRO FORMA INCOME STATEMENT
DECEMBER 31, 1999
(THOUSANDS OF DOLLARS)
(UNAUDITED)

	NRG ENERGY, INC.	CAJUN ELECTRIC (CAJUN FACILITIES)	PRO FORMA ADJUSTMENTS DEBIT	PRO FORMA ADJUSTMENTS CREDIT	NRG ENERGY, INC. PRO FORMA
OPERATING REVENUES					
Revenues from wholly-owned operations	$432,518	$368,562	$ --	$ --	$ 801,080
Equity in earnings of unconsolidated affiliates	67,500				67,500
Total operating revenues	500,018	368,562	--	--	868,580
OPERATING COSTS AND EXPENSES					
Cost of wholly-owned operations	269,900	244,044			513,944
Depreciation and amortization	37,026	37,930		10,361(1)	64,595
General, administrative and development	83,572	16,804			100,376
Total Operating costs and expenses	390,498	298,778	--	10,361	678,915
OPERATING INCOME	109,520	69,784	--	10,361	189,665
OTHER INCOME (EXPENSE)					
Minority interest in earnings of consolidated subsidiary	(2,456)				(2,456)
Gain on sale of interest in projects	10,994				10,994
Write-off of project investments	--	(2,878)			(2,878)
Other income, net	6,432	1,008			7,440
Interest expense	(93,376)		73,248(2)		(166,624)
Total other expense	(78,406)	(1,870)	73,248	--	(153,524)
INCOME (LOSS) BEFORE INCOME TAXES	31,114	67,914	73,248	10,361	36,141
INCOME TAX (BENEFIT) EXPENSE	(26,081)	--	2,080(3)		(24,001)
NET INCOME	$ 57,195	$ 67,914	$75,328	$10,361	$ 60,142

FOOTNOTES

(1) Reflects lower net depreciation/amortization resulting from assets and capitalized costs being depreciated over a longer estimated useful life based on engineering studies.

(2) Reflects accrued interest on $800 million principal amount for 12 months at a rate of 9.156% per annum.

(3) Incremental tax expense due to increased taxable income computed at 41.37%.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Management of
NRG South Central Generating LLC:

In our opinion, the accompanying carve-out statement of net assets and the related carve-out statement of certain revenue and expenses present fairly, in all material respects, the net assets of the Cajun Electric (Cajun Facilities) business to be acquired by Louisiana Generating LLC at December 31, 1999 and 1998, and certain revenue and expenses of its operations for each of the three years in the period ended December 31, 1999 in conformity with accounting principles generally accepted in the United States. These financial statements are the responsibility of NRG South Central Generating LLC'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, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Our audit included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As described in Note 3, the accompanying carve-out financial statements were prepared to present the net assets of the Cajun Electric (Cajun Facilities) business to be acquired by Louisiana Generating LLC and the certain revenue and expenses related to such business and are not intended to be a complete presentation of the assets, liabilities, revenue, expenses and cash flows of Cajun Electric Power Cooperative, Inc.

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
March 7, 2000

CAJUN ELECTRIC (CAJUN FACILITIES)

CARVE-OUT STATEMENT OF NET ASSETS

	DECEMBER 31, 1999	DECEMBER 31, 1998
	(IN THOUSANDS)	
ASSETS		
Utility plant		
Electric plant in service	$1,198,928	$1,191,375
Less: Accumulated depreciation and amortization	632,899	594,539
	566,029	596,836
Construction work in progress	3,996	1,455
Electric plant held for future use	9,904	9,904
	579,929	608,195
Other property and investments		
Non-utility property	670	670
Decommissioning reserve fund	3,518	3,225
	4,188	3,895
Current assets		
Accounts receivable -- electric customers		
Members	25,944	23,504
Nonmembers	6,220	4,725
Accounts receivable -- other	1,678	2,043
Fuel and supplies inventories	34,234	40,578
Prepaids	1,600	1,316
	69,676	72,166
Total assets	653,793	684,256
LIABILITIES		
Current liabilities		
Accounts payable	4,806	2,114
Taxes other than income tax	150	215
Other accrued expenses	8,966	13,904
	13,922	16,233
Decommissioning	3,518	3,225

Total liabilities	17,440	19,458
Net assets	$ 636,353	$ 664,798

See accompanying notes to financial statements.

CAJUN ELECTRIC (CAJUN FACILITIES)

CARVE-OUT STATEMENT OF CERTAIN REVENUE AND EXPENSES

	YEAR ENDED DECEMBER 31,		
	1999	1998	1997
	(IN THOUSANDS)		
Operating revenue			
Sales of electric energy			
Members	$292,090	$289,856	$280,109
Nonmembers	75,258	66,341	65,715
Other	1,214	1,379	958
	368,562	357,576	346,782
Operating expenses			
Power production			
Fuel	165,597	154,964	154,257
Operations and maintenance	36,673	37,405	37,236
Purchased power	10,951	11,645	12,681
Other power supply expenses	577	592	578
Transmission	30,246	29,882	41,687
Administrative and general	9,711	9,122	9,437
Depreciation and amortization	37,930	38,117	39,537
Taxes, other than income	7,093	7,629	8,575
	298,778	289,356	303,988
Operating income	69,784	68,220	42,794
Other income and expenses			
Interest, rents and leases	463	456	695
Other income	545	787	730
Loss on asset dispositions	(2,878)	(5,900)	(481)
	(1,870)	(4,657)	944
Revenues in excess of expenses	$ 67,914	$ 63,563	$ 43,738

See accompanying notes to financial statements.

CAJUN ELECTRIC (CAJUN FACILITIES)

NOTES TO CARVE-OUT FINANCIAL STATEMENTS

1. BUSINESS DESCRIPTION

The accompanying "carve-out" financial statements present the net assets and certain revenue and expenses of the non-nuclear electric power generating business (herein named "Cajun Electric (Cajun Facilities)") of Cajun Electric Power Cooperative, Inc. (the "Cooperative"). The Cooperative is a rural electric generation and transmission cooperative wholly owned by 11 distribution cooperatives (the "Members"). Pursuant to a competitive bidding process following the Cooperative's Chapter 11 bankruptcy proceeding, Louisiana

Generating LLC has agreed to acquire the Cooperative's non-nuclear electric power generating facilities (see Notes 2 and 3). Louisiana Generating LLC is a wholly owned subsidiary of NRG South Central Generating LLC, which in turn is an indirect wholly owned subsidiary of NRG Energy, Inc. NRG Energy, Inc. is a wholly owned subsidiary of Northern States Power Company.

2. BANKRUPTCY PROCEEDING

Bankruptcy Filing

On December 21, 1994 (the "Petition Date"), the Cooperative filed a Petition for Reorganization under Chapter 11 of the United States Bankruptcy Code and began operating as debtor-in-possession under the supervision of the United States Bankruptcy Court for the Middle District of Louisiana (the "Bankruptcy Court"). In August 1995, the United States District Court for the Middle District of Louisiana (the "Court") ordered the appointment of a trustee (the "Trustee") to oversee the Cooperative's operations for the benefit of claim holders and interest holders. All debts of the Cooperative as of the Petition Date were stayed by the bankruptcy petition and subject to compromise pursuant to such proceedings. The Cooperative operated its business and managed its assets in the ordinary course as debtor-in-possession, and was required to obtain Trustee approval for transactions outside the ordinary course of business.

Plan of Reorganization and Acquisition

On January 22, 1996, the Court approved the Trustee's motion to establish procedures for submission of proposals to purchase the Cooperative's assets. The Trustee ultimately selected a bid by NRG Energy, Inc. to create a new limited liability company (Louisiana Generating LLC) to purchase certain non-nuclear assets of the Cooperative. In September 1999, the Bankruptcy Court approved the Plan of Reorganization (the "Plan"), which incorporates the Acquisition Agreement (see Note 3). The purchase price of the assets to be acquired by Louisiana Generating LLC is $1,026 million, subject to adjustment for interest rate fluctuations beyond specific levels. In addition, Louisiana Generating LLC has agreed to reimburse the Members for up $14 million of the expenses that the Members incurred in connection with the bankruptcy of the Cooperative. The transaction is scheduled to close on March 31, 2000, subject to various conditions.

The assets to be acquired by Louisiana Generating LLC include all non-nuclear assets owned by the Cooperative, other than enumerated excluded assets defined in the Acquisition Agreement. Generally, the assets to be acquired consist of:

- Big Cajun I and Big Cajun II, Units 1 and 2;

- the Cooperative's 58% interest in Big Cajun II, Unit 3;

- an energy control center and headquarters building;

- approximately 4,200 acres of agricultural land near Coushatta, Louisiana;

- a 540 MW General Electric steam turbine generator;

- a 17.5 mile gas pipeline system;

- 848 steel rotary dump railcars;

- approximately 38,000 annual sulfur dioxide allowances;

- all coal inventory, oil in storage, materials and supplies;

- the Big Cajun II solid waste closure investment fund; and

- certain transmission assets and all other substations.

Louisiana Generating LLC will not assume any liabilities of the Cooperative, other than (i) obligations under any of the contracts that Louisiana Generating LLC assumes in connection with the acquisition and which arise on or after the closing date of the acquisition, (ii) contingent liabilities related to certain tax benefit transfer agreements to which the Cooperative was a party and (iii) environmental liabilities that may exist related to the transferred property, including the obligation to rehabilitate the Big Cajun II ash and wastewater impoundment areas (see Note 8).

3. BASIS OF PRESENTATION

The accompanying carve-out financial statements have been presented in accordance with generally accepted accounting principles and were derived from the historical accounting records of the Cooperative. The statements are intended to present the net assets and certain revenue and expenses of the Cajun Electric (Cajun Facilities) business to be acquired by Louisiana Generating LLC pursuant to the Fifth Amended and Restated Asset Purchase and Reorganization Agreement among Louisiana Generating LLC, Ralph R. Mabey, as Chapter 11 Trustee of Cajun Electric Power Cooperative, Inc., and NRG Energy, Inc. (as to Sections 7.4, 9.13 and 9.14 of the agreement only) (the "Acquisition Agreement") and the Cooperative's bankruptcy proceedings (see Note 2). Louisiana Generating LLC has agreed to purchase substantially all of the Cooperative's non-nuclear electric power generating facilities and related transmission assets, inventory and other real and personal property. Louisiana Generating LLC will not acquire the "Excluded Assets", as defined in the Acquisition Agreement, which generally consist of the Cooperative's cash, receivables and investments, nor will it assume any liabilities of the Cooperative, except as described in Note 2. Accordingly, the carve-out financial statements do not include all assets, liabilities, revenue and costs and expenses of the Cooperative as of and for the periods presented.

Generally, the statements of net assets exclude the Cooperative's cash, investments (except decommissioning trust fund investments), employee post-retirement benefit obligation, liabilities subject to compromise in the bankruptcy proceeding, income taxes and equity and margin accounts. The statements of certain revenue and expenses exclude the Cooperative's investment earnings (except earnings from the decommissioning trust fund investments), bankruptcy reorganization costs, income taxes, and revenue, expenses and losses related to the ownership, operation and disposal of its 30% interest in the River Bend Nuclear Station in 1997. All long-term debt of the Cooperative is subject to compromise in the bankruptcy proceeding and during the three years ended December 31, 1999 the Cooperative did not record any interest expense thereon in accordance with American Institute of Certified Public Accountants Statement of Position No. 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code." Therefore, the carve-out financial statements do not include any long-term debt of the Cooperative or interest expense thereon.

Although Louisiana Generating LLC will not purchase any receivables or assume any liabilities of the Cooperative, except as described in Note 2, the statements of net assets include receivables, accounts payable and accrued expenses in order to present the historical net assets of the business operation that will be acquired.

The carve-out financial statements do not include a statement of cash flows due to exclusion of cash from the statements of net assets. However, see Note 4 for a summary of cash provided by and used in Cajun Electric's (Cajun Facilities) operating and investing activities.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Significant Customers and Concentrations of Credit Risk

During 1999 sales to two customers totaled 16.7% and 18.9%, respectively, of total operating revenue (1998: 16.7% and 19.2%, respectively; 1997: 16.2% and 19.0%, respectively). No other customer accounted for more than 10% of total operating revenue during the years ended December 31, 1999, 1998 and 1997.

Electric Plant in Service and Construction Work in Progress

Electric plant in service and construction work in progress are stated on the basis of cost. Depreciation is computed using the straight-line method over the expected useful lives of the related component assets. The net book value of units of property replaced or retired, including costs of removal net of any salvage value, is charged to operations.

Fuel and Supplies Inventories

Fuel and supplies inventories are stated on the basis of cost utilizing the weighted-average cost method of inventory valuation.

Fair Values of Financial Instruments

Investments held in the decommissioning reserve fund are comprised of U.S. government debt securities carried at amortized cost, which approximates fair value.

Summary of Cash Flows

Summarized cash flows from operating and investing activities were as follows (in thousands):

	1999	1998	1997
Cash flows from operating activities:			
Revenues in excess of expenses	$ 67,914	$ 63,563	$ 43,738
Adjustments to reconcile net margins to net cash:			
Depreciation and amortization	37,930	38,117	39,537
Asset dispositions	2,878	5,900	481
Changes in accounts receivable	(4,939)	5,988	(2,838)
Changes in fuel and prepayments	6,060	(8,184)	5,315
Changes in accounts payable and accrued expenses	(2,313)	(4,333)	(254)
Net cash provided by operating activities	107,530	101,051	85,979
Cash flows from (for) investing activities:			
Capital expenditures	(11,631)	(9,999)	(7,074)
	$ 95,899	$ 91,052	$ 78,905

5. UTILITY PLANT

Electric plant in service is comprised of the following generating facilities:

GENERATING UNIT	CAPABLE GENERATING CAPACITY	LOUISIANA GENERATING	
		PERCENTAGE	MEGAWATTS
	(UNAUDITED)		(UNAUDITED)
Big Cajun II, Unit 1	575	100%	575
Big Cajun II, Unit 2	575	100%	575
Big Cajun II, Unit 3	575	58%	338
Big Cajun I, Unit 1	110	100%	110
Big Cajun I, Unit 2	110	100%	110
	1,945		1,708

Big Cajun II, Unit 3 is jointly owned by the Cooperative (58%) and Gulf States Utilities (42%). The unit is operated by the Cooperative pursuant to a Joint Ownership Participation and Operating Agreement, which governs the rights and obligations to the ownership of the facility. Each owner is entitled to their ownership percentage of the hourly net electrical output of the unit. All fixed costs of operating the unit are shared in proportion to the respective ownership interests and all variable costs are borne in proportion to the energy delivered to either co-owner. The statements of certain revenue and expenses include the Cooperative's share of all fixed and variable costs of operating the unit. The Cooperative's 58% share of the original cost included in electric plant in service at December 31, 1999 was $291.1 million ($290.9 million at December 31, 1998). The corresponding accumulated depreciation and amortization was $151.1 million ($141.9 million at December 31, 1998).

The Cooperative will assign the Joint Ownership Participation and Operating Agreement to Louisiana Generating LLC upon closing of the acquisition.

Electric plant in service balances at December 31 consisted of the following (in thousands):

	1999	1998
Production:		
Coal	$1,048,012	$1,041,741
Gas	35,368	34,749
Transmission	94,393	94,320
General	21,155	20,565
	$1,198,928	$1,191,375

Construction work in progress consists of improvements and additions to existing plants. The estimated cost to complete these projects at December 31, 1999 was approximately $10.8 million.

Electric plant held for future use of approximately $9.9 million at December 31, 1999 and 1998 consists primarily of land, carried at its original cost of $9.5 million, related to an abandoned lignite project that has been retained as a possible site for a future generating facility.

The net change in accumulated depreciation and amortization for the years ended December 31 was (in thousands):

	1999	1998
Charged to operating expenses..............................	$ 37,930	$ 38,117
Charged to fuel inventories and other assets...............	1,192	1,197
	$ 39,122	$ 39,314
Less: Disposals and other adjustments......................	762	1,435
	$ 38,360	$ 37,879

Substantially all of the assets included in the carve-out statements of net assets are pledged as collateral to the Cooperative's long-term debt payable to the Rural Utilities Service. In addition, certain office facilities have been separately pledged as collateral to the Cooperative's industrial revenue bonds. These obligations are included in the Cooperative's pre-petition liabilities subject to compromise, which have been excluded from the carve-out statement of net assets. Upon execution of the Plan and closing of the acquisition, Louisiana Generating LLC will acquire the assets free of such encumbrances.

6. EMPLOYEE BENEFIT PLANS

All of the Cooperative's employees participate in the National Rural Electric Cooperatives Association (NRECA) Retirement and Security Program once they have met minimum service requirements. The Cooperative makes annual contributions to the plan equal to the amounts accrued for pension expense. In this master multiple-employer defined benefit plan, which is available to all member cooperatives of the NRECA, the accumulated benefits and plan assets are not determined or allocated separately by individual employer. The Cooperative's contributions to the plan and amounts included in the accompanying statements of certain revenue and expenses of Cajun Electric (Cajun Facilities) totaled approximately $1.7 million, $1.7 million and $1.3 million in 1999, 1998 and 1997, respectively.

The Cooperative also maintains a defined contribution pension plan, which constitutes a cash or deferred arrangement under section 401(k) of the Internal Revenue Code of 1986 (as amended). Once minimum service requirements are met, all of the employees of the Cooperative are eligible to participate in the plan. Under the terms of the plan, which is administered by the NRECA, the Cooperative matches 50% of employee contributions up to a maximum of 4% of each participating employee's base

compensation. The Cooperative's contributions to the plan and amounts included in the accompanying statement of certain revenue and expenses of Cajun Electric (Cajun Facilities) totaled approximately $0.4 million, $0.3 million and $0.4 million in 1999, 1998 and 1997, respectively.

The Cooperative also makes medical benefits available to all retirees. For those nonbargaining employees who retire at age 62 or thereafter and who have at least 10 years of service, the Cooperative will pay a portion of the cost. All other retirees are required to pay the full cost of benefits. Net periodic postretirement benefit expense of approximately $0.8 million, $0.8 million and $0.8 million in 1999, 1998 and 1997, respectively, is included in the accompanying statement of certain revenue and expenses.

Upon the closing of the acquisition, all of the Cooperative's employee benefit plans will be terminated, including the defined benefit pension plan, the defined contribution (401(k)) pension plan and the post-retirement healthcare plan and no liabilities related thereto will be assumed by Louisiana

Generating LLC.

7. RATES AND REGULATION

The electric rates charged by the Cooperative to its Members have been subject to the jurisdiction of the Louisiana Public Service Commission ("LPSC"). For the three years ended December 31, 1999, the Cooperative provided capacity and energy to its 11 Members pursuant to "all requirements" power supply agreements. Generally, the all requirements power supply agreements obligated the Cooperative to supply and required the Members to purchase all of the energy and capacity required by the Members for service to its retail customers, with limited exceptions. The Cooperative also provided capacity and energy to three other customers under long-term power agreements and sold excess capacity and energy on a merchant basis to other power suppliers and marketers.

Pursuant to the Acquisition Agreement and the Plan, all 11 Members have elected to terminate, effective on the closing date, their existing all requirements supply agreements with the Cooperative. Each of the 11 Members has selected one of three alternative supply options offered by Louisiana Generating LLC, to be effective immediately after the acquisition closes. Seven of the Members have agreed to purchase power from Louisiana Generating LLC under long-term "all requirements" power supply agreements with terms of 25 years commencing on the acquisition closing. After the initial term, each agreement will continue on a year to year basis unless either party gives the other five years' notice of its intent to terminate the agreement. The remaining four Members have agreed to purchase power from Louisiana Generating LLC under short-term four-year transition power supply agreements. A Member may terminate a short-term agreement upon two years advance notice.

The underlying terms and provisions of the long- and short-term power supply agreements offered by Louisiana Generating LLC and selected by the Members have been approved by the LPSC, which has regulatory authority over the Members. Although the form of the agreements have been approved by the LPSC, each Member must obtain approval from the LPSC of the supply alternative selected. Such approval has been obtained by three of the Members that have elected the long-term agreement. The remaining eight Members are expected to request and receive LPSC approval of their decisions prior to the closing of the acquisition.

Electric Utility Deregulation

On December 17, 1997, the LPSC accepted a staff report finding that deregulation, or retail wheeling, may be in the public interest contingent upon numerous issues being individually and adequately researched. During January 1998, the LPSC investigated the issues of tax implications; unbundling; market structure; market power, reliability, Independent System Operators; stranded costs and benefits; consumer protection, public policy programs and environmental issues; and future regulatory structure and affiliate relationships. In February of 1999, LPSC staff issued a report finding that restructuring is not in the public

interest and recommending that the LPSC defer making a final determination. At its March 1999 Open Session, the LPSC adopted a new procedural schedule to continue its investigation of competitive implications through August of 2000. The effect of deregulation upon Cajun Electric (Cajun Facilities) cannot be determined at this time.

8. OTHER COMMITMENTS AND CONTINGENCIES

Coal Supply and Transportation Agreements

Purchases under the terms of contracts for the acquisition and related transportation of coal during 1999, 1998 and 1997 were approximately $129 million, $136 million and $127 million, respectively. Louisiana Generating LLC will not assume any liabilities incurred by the Cooperative prior to the closing of the acquisition related to the existing coal supply and transportation agreements.

Louisiana Generating LLC has entered into a coal supply agreement under which Triton Coal Company will sell to Louisiana Generating LLC sufficient quantities of coal to satisfy the full coal requirements of the Cajun facilities for a specified period.

Louisiana Generating LLC has entered into a coal transportation agreement with Burlington Northern and Santa Fe Railway Company and American Commercial Terminal LLC which agreement will be effective on the closing date of the acquisition. Pursuant to the agreement, the railroad will transport the coal from the Triton mines in Wyoming to St. Louis, Missouri, and American Commercial Terminal will transport the coal down the Mississippi River from St. Louis to the Cajun facilities.

Decommissioning

The Cooperative is required by the State of Louisiana Department of Environmental Quality ("DEQ") to rehabilitate its Big Cajun II ash and wastewater impoundment areas upon removal from service of the Big Cajun II facilities. On July 1, 1989, the Cooperative established a guarantor trust (the "Solid Waste Disposal Trust Fund") to accumulate the estimated funds necessary for such purpose. The Cooperative deposited $1.06 million in the Solid Waste Disposal Trust Fund in 1989, and has funded $116,000 annually thereafter, based upon the Cooperative's 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, 1999 the carrying value of the trust fund investments and the related accrued decommissioning liability was approximately $3.5 million. The trust fund investments are comprised of various debt securities of the United States and are carried at amortized cost, which approximates their fair value.

The Solid Waste Trust Fund is included in assets to be acquired by Louisiana Generating LLC, which will also assume the obligation to rehabilitate the Big Cajun II ash and wastewater impoundment areas.

Letters of Credit

The Cooperative has outstanding two letters of credit in the aggregate amount of approximately $15 million as of December 31, 1999 supporting potential indemnity payments related to certain tax benefit transfer agreements to which the Cooperative was a party. The letters of credit will be terminated upon the closing of the acquisition. However, as of the closing date, Louisiana Generating LLC will assume the contingent liability related to the potential indemnity payments.

Member Class Action Rate Litigation

On September 20, 1989, a class action petition was filed in the Tenth Judicial District State Court in Natchitoches Parish, Louisiana, naming the Cooperative's Members as defendants. The plaintiffs in this action seek a refund of all rate increases enacted by the Cooperative's Members from 1978 until the respective Member voted to be subject to the jurisdiction of the LPSC or was placed under the jurisdiction of the LPSC by action of the State Supreme Court. On October 17, 1989, the case was moved to the federal courts. On August 28, 1992, the District Court abstained from this matter in favor of proceedings at the LPSC.

The LPSC currently has an open docket associated with this matter. On August 19, 1994, the LPSC adopted the standards recommended by its Special Counsel. Based on those standards, Special Counsel issued a report in August 1996 recommending that 23 of the 29 rate increases implemented during the period of nonregulation be found presumptively not unreasonable and be eliminated from further review. Special Counsel recommended that the remaining six rate increases be further reviewed for reasonableness. On November 18, 1997, the LPSC issued Order U-19943-B dismissing two more rate increases, finding all but the four remaining increases presumptively not unreasonable. On August 19, 1998, the LPSC dismissed two rate increases for Southwest Louisiana Electric Membership Corporation leaving the final two rate increases to be reviewed for reasonableness. A hearing was held on October 12, 1999, on the last two rate increases. The LPSC staff is expected to issue a final report in time for the LPSC to vote on the matter at its March 2000 Open Session. The timing or outcome of this matter is uncertain and no provision for any liability that may result has been made in the financial statements. However, each Member has entered into a stipulation with the Trustee which releases the Bankruptcy Estate from claims by the Members that might arise as a result of any refunds which the LPSC may order. Further, Louisiana Generating LLC will not assume any liability that may result from the outcome of this matter.

INSIDE BACK COVER PAGE

NRG ENERGY, INC. SIGNIFICANT PROJECT LIST

LOCATION	CAPACITY (MW)	NET OWNERSHIP INTEREST (MW)
NORTH AMERICA		
NORTHEAST REGION		
Oswego, Oswego, NY	1,700.0	1,700.0
Middletown, Middletown, CT	856.2	856.2
Arthur Kill, Staten Island, NY	842.0	842.0
Huntley, Tonawanda, NY	760.0	760.0
Astoria Gas Turbines, Queens, NY	614.0	614.0
Dunkirk, Dunkirk, NY	600.0	600.0
Montville, Uncasville, CT	497.6	497.6
Devon, Milford, CT	400.5	400.5
Norwalk Harbor, So. Norwalk, CT	353.0	353.0
Somerset Power, Somerset, MA*	229.0	229.0
Connecticut Turbines, Connecticut	127.4	127.4
Kingston Cogeneration, Kingston, Ontario, Canada	110.0	27.5
Parlin Cogen, Parlin, NJ	122.0	24.4
Grays Ferry Cogen, Grays Ferry, PA	150.0	15.0
SOUTH CENTRAL REGION		
Louisiana Generating LLC, Baton Rouge, LA	1,945.0	1,708.5
Rocky Road, East Dundee, IL	250.0	125.0
Rocky Road (Expansion), East Dundee, IL **	100.0	50.0
Morris Cogen, Morris, IL	117.0	23.4
Pryor Cogen, Pryor, OK	110.0	22.0
Power Smith Cogeneration, Oklahoma City, OK	110.0	9.6
WESTERN REGION		
El Segundo Power, El Segundo, CA	1,020.0	510.0
Encina Power Station, Carlsbad, CA	965.0	482.5
Long Beach Generating, Long Beach, CA	530.0	265.0
Crockett Cogeneration, Crockett, CA	240.0	138.4
San Diego Turbines, San Diego, CA	253.0	126.5
Mt. Poso, Bakersfield, CA	49.5	19.5
OTHER NORTH AMERICA		
NEO, Various	174.5	90.3
Other, Various**	533.7	313.1
Energy Investors Fund, Various	999.0	10.0
TOTAL NORTH AMERICA	14,759	10,940
INTERNATIONAL		
EUROPE		
Killingholme A, North Lincolnshire, England	680.0	680.0
Schkopau, Halle, Germany	960.0	200.0
ECK Generating, Kladno, Czech Republic	345.0	153.5
Enfield Energy Centre, London, England, UK	396.0	99.0
MIBRAG, Thiessen, Germany	233.0	78.0
Energy Center Kladno, Kladno, Czech Republic	28.0	12.4
AUSTRALIA		
Gladstone Power Station, Gladstone, Qld., Australia	1,680.0	630.0
Loy Yang Power A, Traralgon, Vic., Australia	2,000.0	507.4
Collinsville, Collinsville, Qld., Australia	192.0	96.0
Latin America		
COBEE, Bolivia	219.2	108.4

Bulo Bulo, Bolivia	87.0	26.1
OTHER INTERNATIONAL		
Energy Developments, Ltd., Various	274.0	79.1
Scudder Latin American Power, Various Locations	772.0	51.2
Energy Investors Fund, Various	1,035.0	3.0
TOTAL INTERNATIONAL	8,901	2,724
TOTAL WORLDWIDE	23,660	13,664

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*   Includes 69 megawatts on deactivated reserve

**   Includes facilities under construction or suspended operations.

28,170,000 SHARES

NRG ENERGY, INC.

COMMON STOCK

NRG LOGO

PROSPECTUS

MAY 30, 2000

SALOMON SMITH BARNEY

CREDIT SUISSE FIRST BOSTON

ABN AMRO ROTHSCHILD
A DIVISION OF ABN AMRO INCORPORATED

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GOLDMAN, SACHS & CO.
LEHMAN BROTHERS
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MORGAN STANLEY DEAN WITTER