Nuclear Operating Company

South Texas Project Electric Generating Station P.O. Box 289 Wadsworth, Texas 77483

September 29, 2003
NOC-AE-03001612
10 CFR 50.80

U.S. Nuclear Regulatory Commission
Attention: James E. Dyer
Director, Office of Nuclear Reactor Regulation
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

South Texas Project
Units 1 and 2
Docket Nos. STN 50-498 and STN 50-499
Application for Order Approving Indirect Transfer of Control of Licenses

Pursuant to Section 184 of the Atomic Energy Act of 1954, as amended (the Act), and 10 CFR 50.80, STP Nuclear Operating Company (STPNOC), acting on behalf of Texas Genco, LP (Texas Genco), hereby requests that the Nuclear Regulatory Commission (NRC) consent to the indirect transfer of control of Texas Genco's ownership interest in the South Texas Project Electric Generating Station, Units 1 and 2 (STPEGS), described in greater detail below. Texas Genco seeks consent to the indirect transfer of control of its licenses by virtue of the transfer to Reliant Resources, Inc. (Reliant Resources) of ownership of approximately 81% of the stock of Texas Genco's parent company, Texas Genco Holdings, Inc. (TGN), currently owned by CenterPoint Energy, Inc. (CenterPoint Energy).

In addition to its 30.8% undivided ownership interest in STPEGS, Texas Genco holds a corresponding 30.8% interest in STPNOC, a not-for-profit Texas corporation, which is the licensed operator of STPEGS. Thus, the indirect transfer of control of Texas Genco also results in an indirect transfer of control of this 30.8% interest in STPNOC. However, this is not a controlling interest in STPNOC, and therefore, there will be no indirect transfer of control of STPNOC's licenses to operate STPEGS on behalf of the owners. If the NRC concludes that the indirect transfer of control of Texas Genco's interests in STPNOC also requires prior NRC consent, such consent is hereby requested.

Reliant Resources obtained its option to acquire CenterPoint Energy's remaining shares of the common stock of TGN in connection with electric industry restructuring in Texas, and the separation of certain businesses and assets of CenterPoint Energy's predecessor companies. If Reliant Resources exercises its option and acquires CenterPoint Energy's controlling interest in TGN, indirect control over the STPEGS licenses held by Texas Genco, as well as Texas Genco's 30.8% interest in STPNOC, will be transferred from CenterPoint Energy to Reliant Resources.

Through the enclosed Application, Texas Genco requests that NRC consent to this indirect transfer of control. The information contained in this Application demonstrates that Texas Genco will continue to possess the requisite qualifications to own a 30.8% undivided ownership interest in STPEGS. The proposed indirect transfer of control will not result in any change in the role of STPNOC as the licensed operator of the facility and will not result in any changes to its technical qualifications.

In summary, the proposed transfers will be consistent with the requirements set forth in the Act, NRC regulations, and the relevant NRC licenses and orders. No physical changes will be made to STPEGS and there will be no changes in the day-to-day operation of STPEGS as a result of these transfers. The proposed indirect transfer of control will not involve any changes to the current STPEGS licensing basis. It will neither have any adverse impact on the public health and safety, nor be inimical to the common defense and security. This Application therefore respectfully requests that the NRC consent to the indirect transfer of control in accordance with 10 CFR 50.80.

The actual date for any indirect transfer of control of Texas Genco and its 30.8% interests in STPEGS and STPNOC will be dependent upon the actual date of any exercise by Reliant Resources of its option and receipt of financing, and any other required regulatory approvals and rulings. Texas Genco requests that NRC review this Application on a schedule that will permit the issuance of NRC consent to the indirect transfer of control by January 31, 2004. Such consent should be immediately effective upon issuance and should permit the indirect transfer of control at any time until December 31, 2004. STPNOC will inform NRC if there are any significant developments that have an impact on the schedule.

The Application includes a proprietary, separately bound Attachment 3A, which contains confidential commercial or financial information. Texas Genco requests that Attachment 3A be withheld from public disclosure pursuant to 10 CFR 9.17(a)(4) and the policy reflected in 10 CFR 2.790, as described in the Affidavit of David G. Tees provided in Attachment 4 to the Application. A non-proprietary version of this document suitable for public disclosure is provided as Attachment 3 to the Application.

If NRC requires additional information concerning this license transfer request, please contact Mr. Scott Head at (361) 972-7136. Service on STPNOC and Texas Genco of comments, hearing requests or intervention petitions, or other pleadings, if applicable, should be made to Mr. John E. Matthews at Morgan, Lewis & Bockius, LLP, 1111 Pennsylvania Avenue, NW, Washington, DC 20004 (tel: 202-739-5524; fax: 202-739-3001; e-mail: jmatthews@morganlewis.com).

J. J. Sheppard
President & Chief Executive Officer

jtc

Enclosure: Application

cc: w/o proprietary attachment except *
(paper copy)

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AEP Texas Central Company

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)		
	)		
STP Nuclear Operating Company	)	Docket Nos.	50-498
	)		50-499
South Texas Project	)		
Units 1 and 2	)		

AFFIRMATION

I, J. J. Sheppard, being duly sworn, hereby depose and state that I am President & CEO of STP Nuclear Operating Company; that I am duly authorized to sign and file with the Nuclear Regulatory Commission the attached application for order approving indirect transfer of control of licenses; that I am familiar with the content thereof; and that the matters set forth therein with regard to STP Nuclear Operating Company are true and correct to the best of my knowledge and belief.

J. J. Sheppard

STATE OF TEXAS)
)
COUNTY OF MATAGORDA)

Subscribed and sworn to before me, a Notary Public in and for the State of Texas, this 29th day of September, 2003.

LINDA RITTENBERRY
Notary Public, State of Texas
My Commission Expires
OCTOBER 9, 2005

Notary Public in and for the
State of Texas

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
STP Nuclear Operating Company	)	Docket Nos. 50-498
	)	50-499
	)	
South Texas Project	)	
Units 1 and 2	)	

AFFIRMATION

I, David G. Tees, being duly sworn, hereby depose and state that I am Manager and President of Texas Genco GP, LLC, which is the General Partner of Texas Genco, LP; that I am familiar with the content of the attached application for order approving indirect transfer of control of licenses; and that the matters set forth therein with regard to Texas Genco, LP and its affiliates are true and correct to the best of my knowledge and belief.

David G. Tees

David G. Tees

STATE OF TEXAS	)
	)
COUNTY OF HARRIS	)

Subscribed and sworn to before me, a Notary Public in and for the State of Texas, this 23rd day of September, 2003.

NOTARY PUBLIC STATE OF TEXAS
JUNE M. BRADEN
Notary Public, State of Texas
My Commission Expires 4/18/2005

June M. Braden

Notary Public in and for the
State of Texas

STP Nuclear Operating Company
South Texas Project Electric Generating Station P.O. Box 289 Wadsworth, Texas 77483

APPLICATION FOR ORDER APPROVING INDIRECT TRANSFER OF CONTROL OF LICENSES

September 29, 2003

submitted by

STP Nuclear Operating Company
and
Texas Genco, LP

South Texas Project Electric Generating Station, Units 1 and 2
NRC Facility Operating License Nos. NPF-76 and NPF-80
Docket Nos. STN 50-498 and STN 50-499

APPLICATION FOR ORDER APPROVING
INDIRECT TRANSFER OF CONTROL OF LICENSES

TABLE OF CONTENTS

I. INTRODUCTION

This Application requests the consent of the Nuclear Regulatory Commission (NRC) to the proposed indirect transfer of control of Texas Genco, LP's (Texas Genco) 30.8% undivided ownership interest in the South Texas Project Electric Generating Station, Units 1 and 2 (STPEGS) described herein. In addition to its 30.8% undivided ownership interest in STPEGS, Texas Genco holds a corresponding 30.8% interest in STP Nuclear Operating Company (STPNOC), a not-for-profit Texas corporation, which is the licensed operator of STPEGS. Thus, the indirect transfer of control of Texas Genco also results in an indirect transfer of control of this 30.8% interest in STPNOC. However, this is not a controlling interest in STPNOC, and therefore, there will be no indirect transfer of control of STPNOC's licenses to operate STPEGS on behalf of the owners. If the NRC concludes that the indirect transfer of control of Texas Genco's interests in STPNOC also requires prior NRC consent, such consent is hereby requested.

STPEGS is composed of two 1,250 megawatt electric (MWe) (net) nuclear power plants, each consisting of a Westinghouse four-loop pressurized water reactor and other associated plant equipment, and related site facilities. STPEGS is located in southwest Matagorda County, approximately 12 miles south-southwest of Bay City and 10 miles north of Matagorda Bay. STPNOC is the licensed operator for STPEGS, pursuant to licenses issued by the NRC. The two units currently are jointly owned by four entities in the following percentages:

Texas Genco	30.8
City Public Service Board of San Antonio	28.2
AEP Texas Central Company	25.0
City of Austin, Texas	16.0

These same entities hold corresponding percentage interests in STPNOC.

Under the Texas Electric Restructuring Law that was enacted in 1999 and related orders of the Public Utility Commission of Texas, Reliant Energy, Incorporated (REI) was required to split its integrated electric utility operations into separate generation, transmission and distribution, and retail sales companies. Pursuant to those requirements, REI formed CenterPoint Energy, Inc. (CenterPoint Energy) as a new holding company and distributed all its regulated generating facilities to Texas Genco. Under Texas law, Texas Genco is a power generation company, which is not subject to cost-based rate regulation. It is currently seeking certification as an exempt wholesale generator under Section 32 of the Public Utility Holding Company Act of 1935, as amended (PUHCA). As of December 31, 2002, Texas Genco owned and operated a total net generating capacity of 14,175 megawatts, including 30.8% of each of the STPEGS units. Texas Genco is owned by Texas Genco GP, LLC (1%) and Texas Genco LP, LLC (99%). These two companies, in turn, are wholly owned by Texas Genco Holdings, Inc. (TGN), which is publicly traded on the New York Stock Exchange (NYSE) under the symbol "TGN." A simplified organizational chart depicting the current ownership structure of Texas Genco is provided in Figure 1. As of December 31, 2002, the Texas Genco entities had an equity capitalization of approximately $2.8 billion. By Order dated December 20, 2001, the NRC previously determined that Texas Genco would be financially qualified to own 30.8% of STPEGS.

Approximately 81% of the stock of TGN is currently owned by CenterPoint Energy through its wholly-owned subsidiary, Utility Holding LLC, a Delaware limited liability company that holds the stock of TGN and other unregulated businesses of CenterPoint Energy. CenterPoint Energy is publicly traded on the NYSE under the symbol "CNP" and is a registered holding company subject to regulation by the Securities and Exchange Commission (SEC) under PUHCA. Reliant Resources, Inc. (Reliant Resources) is publicly traded on the NYSE under the

symbol (RRI) and was formerly a subsidiary of CenterPoint Energy. On September 30, 2002, CenterPoint Energy distributed to its stockholders all of its remaining common stock of Reliant Resources. Reliant Resources is no longer a subsidiary of CenterPoint Energy. However, under the terms of the agreements providing for the separation of the two companies, Reliant Resources has an option that may be exercised between January 10, 2004 and January 24, 2004 to purchase all of the shares of the common stock of TGN then owned by CenterPoint Energy. It is anticipated that in January 2004, CenterPoint Energy will continue to own approximately 81% of the common stock of, and a controlling interest in, TGN. If Reliant Resources exercises its option and acquires CenterPoint Energy's controlling interest in TGN, indirect control of the STPEGS licenses held by Texas Genco, as well as Texas Genco's 30.8% interest in STPNOC, will be transferred from CenterPoint Energy to Reliant Resources. Reliant Resources would assume the same position as CenterPoint Energy reflected in the current ownership structure depicted in Figure 1.

Through this Application, STPNOC requests, on behalf of Texas Genco, that NRC consent to this indirect transfer of control. The information contained in this Application demonstrates that Texas Genco will continue to possess the requisite qualifications to own a 30.8% undivided ownership interest in STPEGS and STPNOC. The proposed indirect transfer of control will not result in any change in the role of STPNOC as the licensed operator of the facility and will not result in any changes to its technical qualifications.

II. STATEMENT OF PURPOSE OF THE TRANSFERS AND NATURE OF THE TRANSACTION MAKING THE TRANSFERS NECESSARY OR DESIRABLE

CenterPoint Energy has stated an intention to monetize the assets held by the Texas Genco entities (approximately $2.8 billion equity capitalization as of December 31, 2002) as part of the Business Separation Plan approved in December 2000 by the Public Utility Commission

of Texas (Texas Commission) pursuant to the Texas electric restructuring law. The sale of Texas Genco and securitization of any stranded investment in 2004 and 2005, as contemplated by the Texas electric restructuring law, are an integral part of CenterPoint Energy's plan to achieve a more traditional capital structure. As of December 31, 2002, Texas Genco owned and operated eleven power generating stations (60 generating units) and had a 30.8% interest in the STPEGS, for a total net generating capacity of 14,175 MWe. The following table contains information regarding Texas Genco's electric generating assets:

GENERATION FACILITY	NET GENERATING CAPACITY AS OF DECEMBER 31, 2002 (in MWe)
W. A. Parish	3,661
Limestone	1,612
South Texas Project	770
San Jacinto	162
Cedar Bayou	2,260
P. H. Robinson	2,213
T. H. Wharton	1,254
S. R. Bertron	844
Greens Bayou	760
Webster	387
Deepwater	174
H. O. Clarke	78
Total	14,175

Texas Genco sells electric generation capacity, energy, and ancillary services in the Electric Reliability Council of Texas, Inc. (ERCOT) market, which is the largest power market in the State of Texas. Since January 1, 2002, Texas Genco's generation business has been operated as an independent power producer, with output sold at market prices to a variety of purchasers. On January 6, 2003, in accordance with its Business Separation Plan, CenterPoint Energy distributed to its shareholders approximately 19% of the common stock of TGN, Texas

Genco's parent company. This action was taken in order to allow the Texas Commission to determine the market value of the Texas Genco assets in its determination of stranded costs in 2004.

As previously indicated, Reliant Resources may exercise an option in mid-January 2004 to purchase all of the TGN common stock then owned by CenterPoint Energy, and if it does so, it will acquire control of TGN and indirect control of the licenses held by Texas Genco. If Reliant Resources does not exercise the option, CenterPoint Energy currently plans to sell or otherwise monetize its interest in TGN and its subsidiaries. In such event, CenterPoint Energy will seek any required regulatory approvals from the NRC and other governmental entities having jurisdiction over any such transaction.

III. GENERAL CORPORATE INFORMATION REGARDING THE TEXAS GENCO ENTITIES

Detailed information regarding the business and management of the Texas Genco entities is provided in the 2002 Annual Report for TGN (Attachment 1). However, certain key information is provided below.

A. Names

Texas Genco Holdings, Inc.
Texas Genco GP, LLC
Texas Genco LP, LLC
Texas Genco, LP

Together, these entities are referred to herein as the Texas Genco Entities.

B. Address

1111 Louisiana, Houston, TX 77002

C. Description of Business or Occupation

The Texas Genco Entities constitute one of the largest wholesale electric generating

companies in the United States. Through its subsidiaries, TGN owns 60 generating units at eleven electric power generation facilities located in Texas, including a 30.8% interest in STPEGS. TGN sells electric generation capacity, energy, and ancillary services within the ERCOT market, which consists of the majority of the population centers in Texas and facilitates reliable grid operations for approximately 85% of the demand for power in the state.

D. Organization and Management

1. States of Establishment and Place of Business

Texas Genco Holdings, Inc. was incorporated in Texas in August 2001, and Texas is its principal place of business. Texas Genco, LP is a Texas limited partnership that is wholly owned indirectly by TGN. Texas Genco LP, LLC is a Delaware limited liability corporation, which directly owns 99% of Texas Genco. Texas Genco GP, LLC is a Texas limited liability corporation, which directly owns 1% of Texas Genco. These two LLCs are conduit entities that exist solely for tax purposes. Texas is the principal place of business for all of the Texas Genco Entities.

2. Directors and Executive Officers

The following individuals, all of whom are U.S. citizens, are the directors of TGN:

J. Evans Attwell
Donald R. Campbell
Robert J. Cruikshank
Patricia A. Hemingway Hall
David M. McClanahan
Scott E. Rozzell
David G. Tees
Gary L. Whitlock

The following individuals, all of whom are U.S. citizens, are the principal officers of TGN:

David M. McClanahan, Chairman
David G. Tees, President and Chief Executive Officer
Scott E. Rozzell, Executive Vice President, General Counsel and Corporate Secretary
Gary L. Whitlock, Executive Vice President and Chief Financial Officer
James S. Brian, Senior Vice President and Chief Accounting Officer

Joseph B. McGoldrick, Corporate Vice President, Strategic Planning

The following individual, a U.S. citizen, is the Manager of Texas Genco GP, LLC, which is the General Partner that manages and controls Texas Genco, LP:

David G. Tees, Manager

The following individuals, all of whom are U.S. citizens, are officers of Texas Genco GP, LLC:

David G. Tees, President and Chief Executive Officer
Scott E. Rozzell, Executive Vice President, General Counsel and Secretary
Gary L. Whitlock, Executive Vice President and Chief Financial Officer
James S. Brian, Senior Vice President and Chief Accounting Officer
Walter L. Fitzgerald, Vice President and Controller
Marc Kilbride, Vice President and Treasurer
Michael A. Reed, Vice President
Rufus S. Scott, Vice President, Deputy General Counsel and Assistant Secretary
Jerome D. Svatek, Vice President, Asset Management
Richard B. Dauphin, Assistant Secretary
Linda Geiger, Assistant Treasurer

The following individual, a U.S. Citizen, is the only officer for Texas Genco LP, LLC:

Patricia F. Genzel, President and Secretary

Texas Genco, LP is a limited partnership and does not have any officers or directors. Control of Texas Genco, LP is exercised by its General Partner, Texas Genco GP, LLC, by and through its Manager, President and Chief Executive Officer, David G. Tees.

3. Anticipated Changes in Directors and Executive Officers

It is expected that the independent directors on the Board of TGN and operational managers for the Texas Genco Entities will remain in their positions following the transfer of control of TGN to Reliant Resources. However, the directors of TGN who are currently directors of CenterPoint Energy, and the officers of the Texas Genco Entities, who are currently officers of CenterPoint Energy are expected to resign their positions with the Texas Genco

Entities upon a transfer of control to Reliant Resources. Reliant Resources will name replacements for these individuals at a later date, and further information will be provided once these replacements are named.

The following individuals are directors of CenterPoint Energy who are expected to resign their positions with TGN upon a transfer of control:

David M. McClanahan
Scott E. Rozzell
Gary L. Whitlock

The following individuals are officers of CenterPoint Energy who are expected to resign their positions with the Texas Genco Entities upon a transfer of control:

David M. McClanahan	Marc Kilbride
Scott E. Rozzell	Joseph B. McGoldrick
Gary L. Whitlock	Rufus S. Scott
James S. Brian	Richard B. Dauphin
Walter L. Fitzgerald	Linda Geiger

IV. GENERAL CORPORATE INFORMATION REGARDING RELIANT RESOURCES, INC.

Reliant Resources was incorporated in Delaware in August 2000 as part of the Business Separation Plan adopted by CenterPoint Energy (formerly Reliant Energy) to separate its regulated and unregulated operations in accordance with the Texas electric restructuring law. Under that plan, CenterPoint Energy transferred substantially all of its unregulated businesses to Reliant Resources. In May 2001, approximately 20% of the common stock of Reliant Resources was sold in an initial public offering, and on September 30, 2002, approximately 83% of the common stock of Reliant Resources (the percentage of outstanding common stock then owned by CenterPoint Energy) was distributed to the stockholders of CenterPoint Energy. As a result, Reliant Resources is no longer a subsidiary of CenterPoint Energy. Detailed general corporate information, and information regarding the business and management of Reliant Resources is

provided in its 2002 Annual Report (Attachment 2). However, certain key information regarding Reliant Resources is provided below.

A. Name

Reliant Resources, Inc.

B. Address

1111 Louisiana, Houston, TX 77002

C. Description of Business or Occupation

Reliant Resources provides electricity and related services to retail customers primarily in Texas, and acquires and manages the electric energy, capacity, and ancillary services associated with supplying these services. It also provides electric energy and energy services in the competitive segments of the United States wholesale energy markets, owns power generation assets in the Netherlands and a related trading and origination business, and engages in other business activities.

D. Organization and Management

1. State of Establishment and Place of Business

Reliant Resources is a Delaware Corporation with its principal executive offices located in Texas.

2. Directors and Executive Officers

The following individuals, all of whom are U.S. citizens, are the directors of Reliant Resources:

Joel V. Staff
E.William Barnett
Donald J. Breeding
Laree E. Perez
William L. Transier
Kirbyjon H. Caldwell
Steven L. Miller

The following individuals, all of whom are U.S. citizens, are the Executive Officers of Reliant Resources:

Joel V. Staff, Chairman and Chief Executive Officer
Robert W. Harvey, Executive Vice President and Group President, Wholesale
Mark M. Jacobs, Executive Vice President and Chief Financial Officer
Jerry J. Langdon, Executive Vice President and Chief Administrative Officer
Michael L. Jines, Senior Vice President and Acting General Counsel
Thomas C. Livengood, Senior Vice President and Chief Accounting Officer

V. FOREIGN OWNERSHIP OR CONTROL

Reliant Resources is a publicly traded company, and its securities are traded on the New York Stock Exchange and widely held. No filings with the SEC indicate that any alien, foreign corporation, or foreign government holds more than 5% of the securities of Reliant Resources. Therefore, there is no reason to believe that Reliant Resources is owned, controlled, or dominated by any alien, foreign corporation, or foreign government. All of the directors and officers of Reliant Resources are United States citizens. Thus, the transfer of ownership of the TGN shares currently held by CenterPoint to Reliant Resources will not result in any foreign ownership, domination, or control of Texas Genco within the meaning of the Atomic Energy Act of 1954, as amended.

VI. TECHNICAL QUALIFICATIONS

The technical qualifications of STPNOC are not affected by the proposed indirect transfer of control. There will be no physical changes to STPEGS and no changes in the day-to-day operations of STPEGS in connection with the indirect transfer of control. It is anticipated that STPNOC will at all times remain the licensed operator of STPEGS.

VII. FINANCIAL QUALIFICATIONS

A. Projected Operating Revenues and Operating Costs

Texas Genco will continue to own and operate the approximately 14,000 MWe of net

electrical generating capacity, and the operations of Texas Genco will not be materially changed by an indirect transfer of control due to the transfer of ownership of the TGN common stock held currently by CenterPoint Energy to Reliant Resources. Financial information regarding Texas Genco and Reliant Resources is provided in their respective 2002 annual reports that are appended as Attachments 1 and 2. That information and the following additional information confirms that Texas Genco will continue to possess, or have reasonable assurance of obtaining, the funds necessary to cover its *pro rata* share of the estimated operating costs of STPEGS for the period of the licenses in accordance with 10 CFR 50.33(f)(2) and the Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance (NUREG-1577, Rev. 1).

Consolidated Balance Sheets for the Texas Genco Entities are provided at page 48 of TGN's 2002 Annual Report (Attachment 1). Texas Genco has also prepared a Projected Income Statement, including specific line items reflecting the operation of its 30.8% interests in STPEGS, for the five-year period from January 1, 2004 until December 31, 2008. Copies of the Projected Income Statement and related information are contained in a separately bound proprietary Attachment 3A. Texas Genco requests that Attachment 3A be withheld from public disclosure, as described in the Affidavit provided in Attachment 4. Redacted versions of these projections, suitable for public disclosure, are provided as Attachment 3.

The Projected Income Statement shows that anticipated revenues from sales of capacity and energy from STPEGS provide reasonable assurance of an adequate source of funds to meet Texas Genco's *pro rata* share of STPEGS's ongoing operating expenses. Texas Genco will sell its generation in the ERCOT wholesale power markets. The Projected Income Statement through 2008 shows that anticipated revenues from sales of capacity and energy from all of Texas Genco's approximately 14,000 MWe of net generating capacity, averaging an estimated

$2 billion per year, provide assurance that Texas Genco will have an adequate source of funds for its *pro rata* share of STPEGS's ongoing operating expenses.

B. Decommissioning Funding

The financial qualifications of Texas Genco to continue to own a 30.8% undivided ownership interest in STPEGS are further demonstrated by the fact that Texas Genco will continue to provide financial assurance for decommissioning funding in accordance with 10 CFR 50.75. Texas Genco currently maintains and will continue to maintain decommissioning trust funds that have been established to provide funding for decontamination and decommissioning of its 30.8% undivided ownership interest in STPEGS. Texas Genco will continue to maintain these external sinking funds segregated from its assets and outside its administrative control in accordance with the requirements of 10 CFR 50.75(e)(1)(i) and (ii).

In addition, the regulated electric distribution company owned by CenterPoint Energy or its successor will continue to collect from its electric utility ratepayers costs associated with the decommissioning of the 30.8% interest in STPEGS "pursuant to a non-bypassable charge" (within the meaning of 10 CFR 50.75(e)(1)(ii)(B)), and transfer all such funds to Texas Genco or to the decommissioning trust for the benefit of Texas Genco. Texas Genco, in turn, will deposit the amounts received for this purpose into the decommissioning trust. These decommissioning funding arrangements were specifically approved by the Texas Commission. *See* Texas Commission Order, Docket 21956 (March 15, 2001). These arrangements assure that Texas Genco will have the total amount of funds estimated to be needed for decommissioning pursuant to 10 CFR 50.75(c), 50.75(f) and 50.82.

The status of Texas Genco's decommissioning funding as of December 31, 2002 was reported to NRC in Attachment 1 to STPNOC letter (NOC-AE-03001498) dated March 26, 2003. Additional information regarding the decommissioning trusts is provided on page 9 of the

Texas Genco Holdings, Inc. 2002 Annual Report (Attachment 1). Texas Genco does not anticipate any amendments to the Texas Genco Nuclear Decommissioning Master Trust Fund Agreement in connection with the proposed indirect transfer of control. If any amendments are to be made, the existing trust agreement requires prior written notice be made to NRC.

As is amply demonstrated above, in accordance with 10 CFR 50.75, there is reasonable assurance that Texas Genco will obtain the funds necessary to cover its share of the estimated decommissioning costs of STPEGS at the end of licensed operation.

VIII. ANTITRUST INFORMATION

This Application post-dates the issuance of the STP operating licenses, and therefore no antitrust review is required or authorized. Based upon the Commission's decision in *Kansas Gas and Electric Co., et al.* (Wolf Creek Generating Station, Unit 1), CLI-99-19, 49 NRC 441 (1999), the Atomic Energy Act of 1954, as amended, does not require or authorize antitrust reviews of post-operating license transfer applications.

IX. RESTRICTED DATA AND CLASSIFIED NATIONAL SECURITY INFORMATION

The proposed transfers do not contain any Restricted Data or other Classified National Security Information or result in any change in access to such Restricted Data or Classified National Security Information. STPNOC's existing restrictions on access to Restricted Data and Classified National Security Information are unaffected by the proposed transfers.

X. ENVIRONMENTAL CONSIDERATIONS

The requested consent to indirect transfer of control of the STPEGS licenses is exempt from environmental review because it falls within the categorical exclusion contained in 10 CFR 51.22(c)(21), for which neither an Environmental Assessment nor an Environmental Impact Statement is required. Moreover, the proposed indirect transfer does not involve any amendment

to the facility operating licenses or other change and it will not directly affect the actual operation of STPEGS in any substantive way. The proposed transfer does not involve an increase in the amounts, or a change in the types, of any radiological effluents that may be allowed to be released off-site, and involves no increase in the amounts or change in the types of non-radiological effluents that may be released off-site. Further, there is no increase in the individual or cumulative operational radiation exposure and the proposed transfer has no environmental impact.

XI. PRICE-ANDERSON INDEMNITY AND NUCLEAR INSURANCE

The proposed indirect transfer of control does not affect the existing Price-Anderson indemnity agreement for STPEGS, and does not affect the required nuclear property damage insurance pursuant to 10 CFR 50.54(w) and nuclear energy liability insurance pursuant to Section 170 of the Act and 10 CFR Part 140.

XII. EFFECTIVE DATES

The actual date for any indirect transfer of control of Texas Genco and its 30.8% interests in STPEGS and STPNOC will be dependent upon the actual date of any exercise by Reliant Resources of its option and receipt of financing, and any other required regulatory approvals and rulings. Texas Genco requests that NRC review this Application on a schedule that will permit the issuance of NRC consent to the indirect transfer of control by January 31, 2004. Such consent should be immediately effective upon issuance and should permit the indirect transfer of control at any time until December 31, 2004. STPNOC will inform the NRC if there are any significant developments that have an impact on the schedule.

XIII. CONCLUSION

Based upon the foregoing information, STPNOC respectfully requests, on behalf of Texas Genco, that the NRC issue an Order consenting to the indirect transfer of control of the Facility Operating Licenses, Nos. NPF-76 and NPF-80, for Texas Genco's 30.8% undivided ownership interest in STPEGS, as well as its interest in STPNOC to the extent NRC's consent is required.

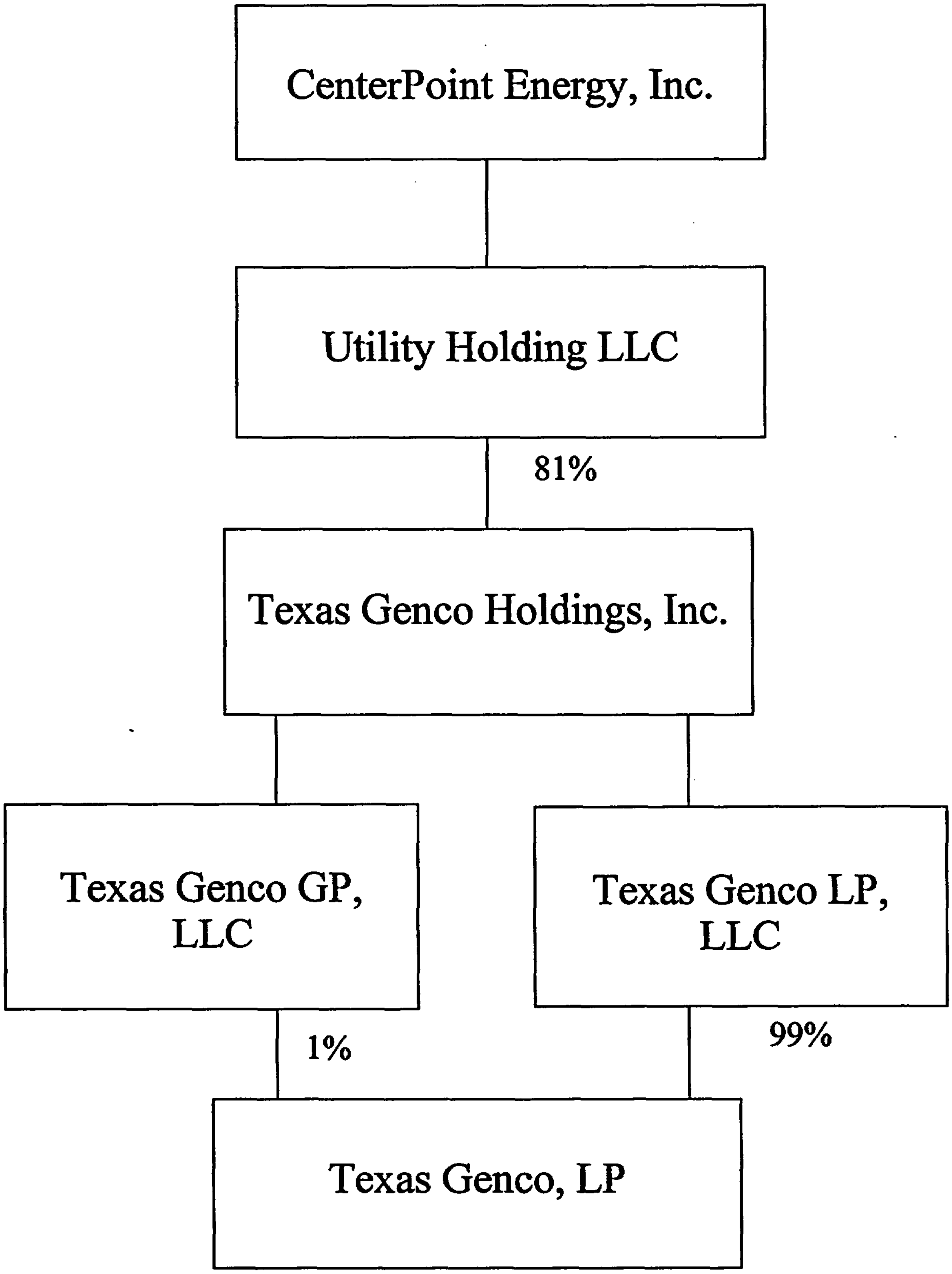
CenterPoint Energy, Inc.
Utility Holding LLC
81%
Texas Genco Holdings, Inc.
Texas Genco GP, LLC
Texas Genco LP, LLC
1%
99%
Texas Genco, LP

Figure 1

ATTACHMENT 1

2002 ANNUAL REPORT OF
TEXAS GENCO HOLDINGS, INC.

TexasGenco

2002 ANNUAL REPORT

We own 60 generating units at 11 electric power generating facilities in Texas and a 30.8 percent interest in the South Texas Project, a nuclear generating plant with two generating units. The aggregate net generating capacity of our portfolio is 14,175 megawatts.

Letter to Shareholders

Welcome to Texas Genco Holdings, Inc.

As a shareholder, you own an interest in one of America's largest independent electric generating companies with a diverse portfolio comprising 14,175 megawatts of installed capacity. Prior to January 1, 2002 when the 1999 Texas electric restructuring law went into effect, our assets were part of an integrated utility where they earned a regulated return. Since the beginning of 2002, power produced by those same generating facilities has been sold at market-based prices. Our first year of operating as an independent electric power generating company in the unregulated, competitive power market has been a challenging one but one that, we believe, has provided a solid foundation for future success.

Common stock distributed

Texas Genco (NYSE: TGN) became a subsidiary of CenterPoint Energy (NYSE: CNP) following the restructuring of Reliant Energy HL&P into three parts: a power generation company, a transmission and distribution utility and a retail electric provider. In December 2002, the CenterPoint Energy board of directors approved the distribution of approximately 19 percent of Texas Genco common stock to CenterPoint Energy shareholders. On January 6, 2003, CenterPoint Energy shareholders received one share of Texas Genco common stock for every 20 shares of CenterPoint Energy common stock they owned. Reliant Resources, Inc. (NYSE:RRI), a former affiliate, has an option to purchase the remaining 81 percent share of Texas Genco from CenterPoint Energy in January 2004.

Law brings competition

In the state's competitive market structure, we're required by law to auction firm entitlements to 15 percent of our available generating capacity on a forward basis for varying terms of up to two years. We are obligated to conduct these auctions until the Public Utility Commission of Texas determines that retail electric providers other than Reliant Resources are providing at least 40 percent of the power that residential and small commercial customers consumed in 2000 in the CenterPoint Energy electric distribution area. Otherwise, we will continue the auctions until January 1, 2007.

We are further obligated by contract to auction capacity entitlements to substantially all of the capacity and related ancillary services that are available after the state-mandated auctions until the Reliant Resources option is exercised or expires in 2004. We are, however, permitted to reduce by 1,250 MW the amount sold in the contractually mandated auctions in order to have an operating reserve to back up our obligations.

Prices received for power in 2002 were substantially below the regulated rates we had received in the past. The Texas electric industry restructuring law prompted a significant number of new, efficient natural gas-fired electric generating plants to be built in the state. The Electric Reliability Council of Texas (ERCOT), which represents the market into which we sell our power, currently has an excess of electric generating capacity similar to other power markets nationally, which created a weak pricing environment and reduced demand for older, less-efficient generat-

David M. McClanahan
Chairman

David G. Tees
President and
Chief Executive Officer

ing capacity. These unfavorable market conditions led us in October 2002 to "mothball" approximately 3,400 MW of our gas-fired generating units through May 2003. Along with this decision, we implemented a voluntary early retirement package that was accepted by 94 employees.

With these dramatic changes in the state's electricity industry and in the power market environment, our revenue and operating income dropped sharply from amounts realized when we were part of an integrated electric utility. For 2002, we incurred a loss before interest and taxes of $130 million on revenues of $1.5 billion.

For 2003, however, we expect improved financial performance, based on the capacity auctions we've completed so far. Through the January 2003 capacity auctions, 74 percent of our available 2003 capacity had already been sold at prices that were substantially higher than the prices we received in the previous year. We attribute the auction price increases to higher prices for natural gas, the fuel that sets the marginal price for electricity in ERCOT. High natural gas prices produce improved margins in our base load generating units that primarily use lower cost coal, lignite and nuclear fuels.

Our strategy

Going forward, our strategy is to maximize earnings and cash flow by maintaining our lower-cost solid fuel generating units at high levels of availability, capitalizing on the size and diversity of our generation portfolio and our operating experience, and by aggressively managing our fuel costs. We also intend to capitalize on fuel cost savings under our joint operating agreement with the City Public Service Board of San Antonio, as well as continue to reduce our operating expenses.

Our objective is to pay regular quarterly dividends on our common stock, subject to the financial performance and related cash flow of the company. Our initial dividend rate was set at 25 cents per quarter and we paid our first quarterly dividend on March 20, 2003.

With restructuring and competition, we knew we faced a number of challenges and uncertainties in 2002. We expect to have a much better year in 2003 as a result of increased operating efficiencies and an improved pricing environment.

We're working hard to earn your trust and to increase the value of your investment.

Sincerely,

David M. McClanahan
David M. McClanahan
Chairman

David G. Tees
David G. Tees
President and Chief Executive Officer

Board of Directors

J. Evans Attwell, 72, is the retired Managing Partner of Vinson & Elkins L.L.P. Director of Texas Genco since March 2003.

Donald R. Campbell, 62, is a private investor and the retired Chief Financial Officer of Sanders Morris Harris Group, Inc. Director of Texas Genco since March 2003.

Robert J. Cruikshank, 72, is a private investor and retired senior partner with Deloitte & Touche LLP. Director of Texas Genco since March 2003.

Patricia A. Hemingway Hall, 50, is President of Blue Cross and Blue Shield of Texas, Inc., a division of Health Care Service Corporation. Director of Texas Genco since March 2003.

David M. McClanahan, 53, is Chairman of the Board of Directors. He also serves as director and President and Chief Executive Officer of CenterPoint Energy, Inc. Director of Texas Genco since its inception.

Scott E. Rozzell, 54, is Executive Vice President, General Counsel and Corporate Secretary of Texas Genco and of CenterPoint Energy, Inc. Director of Texas Genco since March 2003.

David G. Tees, 58, is President and Chief Executive Officer of Texas Genco. Director of Texas Genco since December 2002.

Gary L. Whitlock, 53, is Executive Vice President and Chief Financial Officer of Texas Genco and of CenterPoint Energy, Inc. Director of Texas Genco since March 2003.

Officers

David M. McClanahan, 53
Chairman

David G. Tees, 58
President and Chief Executive Officer

Scott E. Rozzell, 54
Executive Vice President, General Counsel and Corporate Secretary

Gary L. Whitlock, 53
Executive Vice President and Chief Financial Officer

James S. Brian, 55
Senior Vice President and Chief Accounting Officer

Walter L. Fitzgerald, 45
Vice President and Controller

Marc Kilbride, 50
Vice President and Treasurer

Joseph B. McGoldrick, 49
Corporate Vice President
Strategic Planning

Michael A. Reed, 49
Vice President
Plant Operations

Rufus S. Scott, 59
Vice President, Deputy General Counsel and Assistant Corporate Secretary

Jerome D. Svatek, 47
Vice President
Asset Management

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2002

or

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

For the transition period from to

Commission File Number 1-31449

Texas Genco Holdings, Inc.
(Exact name of registrant as specified in its charter)

Texas *(State or other jurisdiction of incorporation or organization)*	**76-0695920** *(I.R.S. Employer Identification Number)*
1111 Louisiana **Houston, Texas 77002** *(Address and zip code of principal executive offices)*	**(713) 207-1111** *(Registrant's telephone number, including area code)*

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $.001 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

CenterPoint Energy, Inc. owned all of the outstanding shares of common stock of Texas Genco Holdings, Inc. (Company) as of the last business day of the Company's most recent completed second fiscal quarter. The aggregate market value of the voting stock held by non-affiliates of the Company was $243,071,014 as of February 25, 2003, using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers. As of February 25, 2003, the Company had 80,000,000 shares of Common Stock outstanding.

Portions of the definitive proxy statement relating to the 2003 Annual Meeting of Shareholders of the Company, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2002, are incorporated by reference in Item 10, Item 11, Item 12 and Item 13 of Part III of this Form 10-K.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Actual results may differ materially from those expressed or implied by these statements. You can generally identify our forward-looking statements by the words "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "objective," "plan," "potential," "predict," "projection," "should," "will," or other similar words.

We have based our forward-looking statements on our management's beliefs and assumptions based on information available to our management at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, we cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements.

Some of the factors that could cause actual results to differ from those expressed or implied by our forward-looking statements are described under "Risk Factors" beginning on page 20 in Item 1 of this report.

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to publicly update or revise any forward-looking statements.

PART I

Item 1. *Business.*

OUR BUSINESS

General

We are one of the largest wholesale electric power generating companies in the United States. We own 60 generating units at 11 electric power generation facilities located in Texas. We also own a 30.8% interest in the South Texas Project Electric Generating Station (South Texas Project), a nuclear generating station with two 1,250 megawatt (MW) nuclear generating units. As of December 31, 2002, the aggregate net generating capacity of our portfolio of assets was 14,175 MW. We sell electric generation capacity, energy and ancillary services within the Electric Reliability Council of Texas, Inc. (ERCOT) market. The ERCOT market consists of the majority of the population centers in the State of Texas and facilitates reliable grid operations for approximately 85% of the demand for power in the state.

In June 1999, the Texas legislature enacted legislation (Texas electric restructuring law) which substantially amended the regulatory structure governing electric utilities in Texas in order to encourage retail electric competition. Under the Texas electric restructuring law, we ceased to be subject to traditional cost-based regulation. Since January 1, 2002, we have been selling generation capacity, energy and ancillary services to wholesale purchasers at prices determined by the market. Accordingly, our historical financial information and operating data, such as demand and fuel data, covering periods prior to 2002 do not reflect what our financial position, results of operations and cash flows would have been had our generation facilities been operated during those periods under the current deregulated ERCOT market.

As a result of requirements under the Texas electric restructuring law and agreements with our parent company, CenterPoint Energy, Inc. (CenterPoint Energy), we are obligated to sell substantially all of our capacity and related ancillary services through 2003 pursuant to capacity auctions. In these auctions, we sell firm entitlements to capacity and ancillary services on a forward basis dispatched within specified operational constraints. For more information regarding our auctions, please read "Capacity Auctions and Opportunity Sales" below.

CenterPoint Energy registered and became subject, with its subsidiaries, to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (1935 Act). The 1935 Act directs the Securities and Exchange Commission (SEC) to regulate, among other things, transactions among affiliates, sales or acquisitions of assets, issuances of securities, distributions and permitted lines of business.

Texas Genco Holdings, Inc. (Texas Genco) was incorporated in Texas in August 2001. Our executive offices are located at 1111 Louisiana, Houston, Texas 77002, and our telephone number is (713) 207-1111. The generating assets of Texas Genco are owned and operated by Texas Genco, LP, its indirect wholly owned subsidiary. In this report, the terms "we," "us" or similar terms mean Texas Genco and its subsidiaries, unless the context indicates otherwise, while references to Texas Genco mean only the parent company.

We make available free of charge on our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such reports with, or furnish them to, the SEC. Our website address is http://www.txgenco.com.

Formation, Distribution and Reliant Resources Option

Texas Genco is an indirect majority owned subsidiary of CenterPoint Energy. Our portfolio of generation facilities was formerly owned by the unincorporated electric utility division of Reliant Energy, Incorporated (Reliant Energy), the predecessor of CenterPoint Energy Houston Electric, LLC (CenterPoint Houston). CenterPoint Houston is an indirect wholly owned subsidiary of CenterPoint Energy. Reliant Energy conveyed these facilities to us in accordance with a business separation plan adopted in response to the Texas electric

restructuring law. For convenience, we describe our business in this report as if we had owned and operated our generation facilities prior to the date they were conveyed to us. On January 6, 2003, CenterPoint Energy distributed approximately 19% of the 80,000,000 outstanding shares of Texas Genco's common stock to CenterPoint Energy's common shareholders (distribution). CenterPoint Energy now indirectly owns approximately 81% of the outstanding shares of Texas Genco's common stock. For more information regarding our formation and the distribution, please read "Background of the Distribution of Texas Genco Shares" below.

A former subsidiary of CenterPoint Energy, Reliant Resources, Inc. (Reliant Resources), has an option (Reliant Resources option) to purchase the shares of Texas Genco common stock owned by CenterPoint Energy exercisable in January 2004. For more information regarding this option, please read "Reliant Resources Option" below. CenterPoint Energy has stated that if Reliant Resources does not exercise its option to purchase CenterPoint Energy's interest in Texas Genco in 2004, CenterPoint Energy will consider strategic alternatives for its interest, including a possible sale.

The ERCOT Market

The ERCOT market consists of the State of Texas, other than a portion of the panhandle, a portion of the eastern part of the state bordering on Louisiana and the area in and around El Paso. The ERCOT market represents approximately 85% of the demand for power in Texas and is one of the nation's largest power markets. The ERCOT market includes an aggregate net generating capacity of approximately 70,000 MW. There are only limited direct current interconnections between the ERCOT market and other power markets in the United States.

The ERCOT market operates under the reliability standards set by the North American Electric Reliability Council. The Public Utility Commission of Texas (Texas Utility Commission) has primary jurisdiction over the ERCOT market to ensure the adequacy and reliability of electricity supply across the state's main interconnected power transmission grid. The ERCOT independent system operator (ERCOT ISO) is responsible for maintaining reliable operations of the bulk electric power supply system in the ERCOT market. Its responsibilities include ensuring that electricity production and delivery are accurately accounted for among the generation resources and wholesale buyers and sellers. Unlike independent systems operators in other regions of the country, the ERCOT market is not a centrally dispatched power pool and the ERCOT ISO does not procure energy on behalf of its members other than to maintain the reliable operations of the transmission system. Members are responsible for contracting sales and purchases of power bilaterally. The ERCOT ISO serves as agent for procuring ancillary services for those market participants who elect not to provide their own ancillary services.

The amount by which power generating capacity exceeded peak demand (reserve margin) in the ERCOT market has exceeded 20% since 2001, and the Texas Utility Commission and the ERCOT ISO have forecasted the reserve margin for 2003 to continue to exceed 20%. The commencement of commercial operation of new facilities in the ERCOT market will increase the competitiveness of the wholesale power market, which could have a material adverse effect on our business, results of operations, financial condition and cash flows and the market value of our assets.

Since January 1, 2002, any wholesale producer of electricity that qualifies as a "power generation company" under the Texas electric restructuring law and that can access the ERCOT electric grid is allowed to sell power in the ERCOT market at unregulated rates. Transmission capacity, which may be limited, is needed to effect power sales. In the ERCOT market, buyers and sellers enter into bilateral wholesale capacity, energy and ancillary services contracts or may participate in the centralized ancillary services market, which the ERCOT ISO administers. Also, companies whose power generation facilities were formerly part of integrated utilities, like us, are required to auction entitlements to 15% of their capacity. For additional information regarding these auctions, please read "Capacity Auctions and Opportunity Sales—State Mandated Auctions" below. Wholesale buyers and sellers may also engage in spot market transactions in the ERCOT market. We expect the ERCOT market will be a very competitive market under the framework established by the Texas electric restructuring law.

The transmission capacity available in the ERCOT market affects power sales. The power transfer from generators to meet demand across a transmission line is limited by the transfer capability of the line. Therefore, power sales or purchases from one location to another may be constrained by the power transfer capability between locations. A transmission path with significant power flow, the loss of which may cause system reliability problems, is identified as a commercially significant constraint. When scheduled power transfers across transmission facility elements exceed the transfer capability of such elements, the transmission facility is constrained and transmission congestion is declared by the ERCOT ISO. Transmission congestion is then resolved through the use of ancillary services and unit specific deployments to reduce the transfer across the constrained facility. With the addition of new loads, generators and transmission facilities and the re-rating of older facilities, the commercially significant constraints and transfer capabilities can change. Under current protocol, the commercially significant constraints and the transfer capabilities along these paths are reassessed every year. Currently, there are four congestion zones in the ERCOT market. The reserve margins may vary by congestion zone. The ERCOT ISO has also instituted direct assignment of congestion cost to those parties causing the congestion. This has the potential to increase the power generator's exposure to the congestion costs associated with transferring power between zones.

Capacity Auctions and Opportunity Sales

State Mandated Auctions

As a power generation company that has been unbundled from an integrated electric utility, we are required by the Texas electric restructuring law to sell at auction firm entitlements to 15% of our installed generation capacity on a forward basis for varying terms of up to two years. We refer to the auctions held to satisfy this requirement as "state mandated auctions." Our obligation to conduct state mandated auctions will continue until January 1, 2007, unless before that date the Texas Utility Commission determines that loads equal to or exceeding 40% of the electric power consumed in 2000 before the onset of retail competition in Texas by residential and small commercial customers in CenterPoint Houston's service area are being served by retail electric providers not affiliated or formerly affiliated with CenterPoint Energy. Reliant Resources is deemed to be an affiliate of CenterPoint Energy for purposes of this test. Reliant Resources is currently not permitted under the Texas electric restructuring law to purchase capacity sold by us in the state mandated auctions.

The capacity entitlements we are required to offer in the state mandated auctions are determined by rules adopted by the Texas Utility Commission. Under these rules, we are required to sell entitlements to 15% of our installed generation capacity in blocks of 25 MW each. Texas Utility Commission rules require 50% of the 25 MW blocks we sell in these auctions to consist of one-month allocations, or "strips," 30% to consist of one-year strips, and 20% to consist of two-year strips. Purchasers of our capacity entitlements offered in the state mandated auctions may resell them to third parties, other than Reliant Resources. We only auction entitlements to capacity dispatched within specified operational constraints to specific zonal delivery points and the entitlements do not convey any right to have power dispatched from a specific generating unit. This enables us to dispatch our commitments in the most cost-effective manner available. This also exposes us to the potential risk that in the event one of our low-cost base-load facilities is shut down, we may be required to satisfy our commitments with the output of higher cost facilities or with replacement power purchased from third parties in the open market.

The types of capacity entitlements we offer in our state mandated auctions include:

- base-load entitlements, representing our solid fuel and nuclear powered generation capacity, that provide energy at a relatively low fixed price and include limited ancillary services capabilities;
- intermediate entitlements, representing various gas-fired generation capacity, that provide energy indexed to natural gas prices and at a specified heat rate and include flexible ancillary service capabilities;

- cyclic entitlements, representing various other gas-fired generation capacity, that provide energy indexed to natural gas prices and at a specified heat rate and include flexible ancillary service capabilities; and

- peaking entitlements, representing various smaller gas-fired generation capacity, that provide energy indexed to natural gas prices and at a specified heat rate and include limited ancillary service capabilities.

Each of these categories of capacity entitlements is generally designed to have operating characteristics similar to the assumed underlying generating units. For example, base-load entitlements can be started once a month, whereas cyclic entitlements can be started up to 20 times a month.

Contractually Mandated Auctions

We are contractually obligated to auction entitlements to substantially all of our capacity and related ancillary services available after the state mandated auctions until the date on which the Reliant Resources option either is exercised or expires. We refer to the auctions held to satisfy this obligation as "contractually mandated auctions." We are, however, permitted to reduce the amount of capacity we sell in the contractually mandated capacity auctions by the amount of operating reserves required to back up our obligations under our capacity auctions. Since we sell the majority of our capacity as firm entitlements, we typically reserve 1,250 MW of our capacity as operating reserves, which can be sold as interruptible power on a system-contingent basis.

Prior to each contractually mandated auction, we determine the types of capacity entitlements we will auction after taking into consideration anticipated market demand and the auction principles required under our agreements with CenterPoint Energy. We intend to hold our contractually mandated auctions during the same time periods as our state mandated auctions to the extent market and other conditions permit. Under these principles we:

- are required to offer a variety of capacity entitlements and ancillary services in the contractually mandated auctions so as to capture the full value of our generation assets;

- may not withhold capacity from the ERCOT market, subject to the permitted reductions described above;

- are required to offer a full array of ancillary services consistent with the capability of our generating units; and

- may sell at terms acceptable to us in our sole discretion any capacity that is not sold in the contractually mandated auctions or any capacity entitlement not taken by the entitlement holder.

As described above under "— State Mandated Auctions," we offer entitlements to our base-load, intermediate, cyclic and peaking capacity in our contractually mandated auctions. However, we may vary the terms and conditions of the entitlements we sell in our contractually mandated auctions from those we offer in our state mandated auctions. The scale and diversity of our generation portfolio enables us to offer a greater variety of capacity entitlements than some of our competitors. We attempt to increase the overall profitability of our portfolio by offering capacity entitlements with a variety of operating characteristics through our contractually mandated auctions.

Through 2003, Reliant Resources has the contractual right, but not the obligation, to purchase 50% (but not less than 50%) of each type of capacity entitlement we auction in the contractually mandated auctions at the prices established in the auctions. To exercise this right, Reliant Resources is required to notify us whether it elects to purchase 50% of the capacity auctioned no later than three business days prior to the date of the auction. We exclude the amount of capacity specified in Reliant Resources' notice from the auction. We auction any portion of the capacity that Reliant Resources does not reserve through its notice in the contractually mandated auctions.

Upon determination of the prices for the capacity entitlements we auction, Reliant Resources is obligated to purchase the capacity it elected to reserve from the auction process at the prices set during the auction for that entitlement. If we auction capacity and ancillary services separately, Reliant Resources is entitled to participate in 50% of the offered capacity of each. In addition to its reservation of capacity, and whether or not it has reserved capacity in the auction, Reliant Resources is entitled to participate in each contractually mandated auction. If Reliant Resources exercises the Reliant Resources option, we will not conduct any capacity auctions, other than as required by Texas Utility Commission rules, between the option exercise date and the option closing date without obtaining Reliant Resources' consent, which it may not unreasonably withhold. If Reliant Resources does not exercise its option, we will no longer be required to conduct contractually mandated auctions following the expiration of that option.

Auction Pricing Methodology

Revenues derived from our capacity auctions come from two sources: capacity payments and energy payments. Capacity payments are based on the final clearing prices, in dollars per kilowatt-month, determined during the auctions. We bill and collect for these capacity payments on a monthly basis just prior to the month of the entitlement. Energy payments consist of a variety of charges related to the fuel and ancillary services scheduled through our auctioned capacity entitlements. The energy payments we collect for capacity entitlements with underlying coal-fired, lignite-fired or nuclear capacity are based on a preestablished price derived from the Texas Utility Commission's forecasted fuel costs. The energy payments we collect for capacity entitlements with underlying gas-fired capacity are calculated using specified heat rates and the published Houston Ship Channel price for natural gas. Additional charges, referred to as "adders," are included in the energy payments to cover additional costs we incur when we are required to operate our facilities at less efficient operating ranges. We bill for these energy payments on a monthly basis in arrears.

Auction Results

We conducted our initial state mandated auctions and contractually mandated auctions from September 2001 through January 2003. Thirty-one companies, including Reliant Resources, registered and qualified to participate in these auctions. As a result, we sold 91% of our available capacity for 2002 and 74% of our available capacity for 2003. Our available capacity equals our total net generating capacity less capacity withheld as operating reserves and capacity that is subject to planned outages. The 3,400 MW of capacity that we have "mothballed" as described below under "— Recent Plant Mothballing" is included in our available capacity only for the months of June through September 2003. We intend to hold auctions to sell our remaining available capacity for 2003 in March and July 2003.

Reliant Resources purchased entitlements to 63% of our available 2002 capacity and through January 2003, has purchased 58% of our available 2003 capacity. These purchases have been made either through the exercise by Reliant Resources of its contractual rights to purchase 50% of the entitlements auctioned in the contractually mandated auctions or through the submission of bids in those auctions.

To date, the market-based prices established in our capacity auctions have provided returns on our facilities substantially below historical regulated returns experienced by our integrated utility in the past. As discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations" in Item 7 of this report, the pricing of our generation products is sensitive to gas prices. Higher gas prices in the latter part of 2002 and early 2003 have positively influenced the prices established in our recent capacity auctions. Generally, higher gas prices increase the capacity prices for our base-load entitlements since these entitlements are solid fuel with fixed fuel prices and prospective purchasers face higher-cost and more volatile priced gas-fired generation alternatives.

Opportunity Sales

In addition to our capacity auctions, from time to time we sell energy on a short-term basis from the generating capacity we use as operating reserves. Any significant unforeseen outage at our base-load or other facilities could adversely impact revenues generated by these sales. We seek to maximize our opportunity sales

by seeking to optimize the dispatching of the various facilities in our generating portfolio. For example, we can meet the gas-fired auction products (intermediate, cyclic and peaking) with generation from our lower cost base-load operating reserves when they are available, since entitlements to our auction products convey no right to specific units. Thus, the capacity factor on the base load capacity has a significant impact on the level of these opportunity sales through the course of the year.

Our Generation Portfolio

Overview

We own 60 generating units at 11 electric power generation facilities located in Texas. We also own a 30.8% interest in the South Texas Project, a nuclear generating plant consisting of two 1,250 MW generating units. As of December 31, 2002, the aggregate net generating capacity of our combined portfolio of generation assets was 14,175 MW, which represents nearly 20% of the total net generating capacity serving the ERCOT market.

Summary of Our Generation Facilities (As of December 31, 2002)

Generation Facilities	Net Generating Capacity (in MW)(1)	Number of Units	Dispatch Type	Fuel
W. A. Parish	3,661	9	Base-load, Intermediate, Cyclic, Peaking	Coal/Gas
Limestone	1,612	2	Base-load	Lignite
South Texas Project(2)	770	2	Base-load	Nuclear
Cedar Bayou	2,260	3	Intermediate	Gas/Oil
P. H. Robinson(3)	2,213	4	Intermediate	Gas
San Jacinto	162	2	Intermediate	Gas
T. H. Wharton(3)	1,254	18	Cyclic, Peaking	Gas/Oil
S. R. Bertron	844	6	Cyclic, Peaking	Gas/Oil
Greens Bayou(3)	760	7	Cyclic, Peaking	Gas/Oil
Webster(3)	387	2	Cyclic, Peaking	Gas
Deepwater(3)	174	1	Cyclic	Gas
H. O. Clarke	78	6	Peaking	Gas
Total	14,175	62		

(1) Net generating capacity equals gross maximum summer generating capability less the electric energy consumed at the facility.

(2) Represents our 30.8% interest in the South Texas Project.

(3) In October 2002, we announced our plan to mothball all 2,213 MW of capacity at our P.H. Robinson facility, 229 MW of capacity at our T.H. Wharton facility, 406 MW of capacity at our Greens Bayou facility, 374 MW of capacity at our Webster facility and all 174 MW of capacity at our Deepwater facility through at least May 2003. Please read "— Recent Plant Mothballing."

Base-Load and Intermediate Facilities

W.A. Parish. Our W.A. Parish facility is the largest coal and gas-fired power facility in the United States based on total MW of net generating capacity. The facility consists of a coal-fired plant and a gas-fired plant each located near Thompsons, Texas. The coal-fired plant includes four steam generating units for base-load service with an aggregate net generating capacity of 2,470 MW. Two of these units are 650 MW steam

units that were placed in commercial service in December 1977 and December 1978, respectively. The other two units are 560 MW and 610 MW steam units that were placed in commercial service in June 1980 and December 1982, respectively.

The gas-fired plant includes five generating units with an aggregate net generating capacity of 1,191 MW. Two of these units are 174 MW steam units that were placed in commercial service in June 1958 and December 1958, respectively. These units were converted for daily cyclic operation and the life of the units was extended in 1990 and 1991. The third unit at this plant is a 278 MW steam unit that was placed in commercial service in March 1961. These three units provide cyclic capacity. The fourth unit is a 552 MW steam unit for intermediate service that was placed in service in June 1968. This plant also has a 13 MW gas turbine generator unit available for peaking and emergency start-up purposes that was placed in service in July 1967.

Limestone. Our Limestone facility is a lignite-fired base-load facility located approximately 120 miles northwest of Houston. This plant includes two steam generating units with an aggregate net generating capacity of 1,612 MW. The first unit is an 846 MW steam unit that was placed in commercial service in December 1985. The second unit is a 766 MW steam unit that was placed in commercial operation in December 1986.

Cedar Bayou. Our Cedar Bayou facility is a gas and oil-fired intermediate facility located east of Baytown, Texas. This plant includes three generating units with an aggregate net generating capacity of 2,260 MW. Two of the units are 750 MW steam units that were placed in service in December 1970 and March 1972, respectively. The third unit is a 760 MW steam unit that was placed in service in December 1974.

P.H. Robinson. Our P. H. Robinson facility is a gas-fired intermediate facility located east of San Leon, Texas. This plant consists of four steam generating units with an aggregate net generating capacity of 2,213 MW. Two of the units are 461 MW units that were placed in service in June 1966 and April 1967, respectively. The third unit is a 552 MW unit that was placed in service in December 1968. The fourth unit is a 739 MW unit that was placed in service in December 1973.

San Jacinto. Our San Jacinto facility is a 162 MW gas-fired intermediate facility located in LaPorte, Texas that produces both steam and power. This plant includes two cogeneration units and associated equipment. Both units began commercial operation in April 1995. Each unit consists of a gas turbine that drives an air-cooled generator with the exhaust from the gas turbine being sent to a heat recovery steam generator.

Cyclic and Peaking Facilities

T.H. Wharton. Our T. H. Wharton facility is a gas and oil-fired cyclic and peaking facility located in Houston. This plant consists of 18 steam and gas turbine units with an aggregate net generating capacity of 1,254 MW. This facility includes a 229 MW steam unit for cyclic service that was placed in commercial operation in June 1960 and a 13 MW small gas turbine unit for peaking service that was placed in commercial operation in July 1967. In addition, six 57 MW gas turbines were placed in service at this facility in July 1972. An additional two 57 MW gas turbines and two 104 MW steam turbines were installed in August 1974 and were combined with the six gas turbines already in service to develop two combined cycle units for intermediate service. An additional six 58 MW gas turbines for peaking service were placed in service in November 1975.

S.R. Bertron. Our S. R. Bertron facility is a gas and oil-fired cyclic and peaking facility located in Deer Park, Texas. This plant consists of four steam electric generating units, one auxiliary boiler for cyclic operations, and two gas turbine generators with an aggregate net generating capacity of 844 MW. The first two units at this plant are 174 MW steam units for cyclic service that commenced commercial operation in April 1956 and March 1958, respectively. Both of these units underwent cyclic conversion and life extension in 1989 and 1990. The third and fourth units at this plant are 230 MW steam units that commenced commercial operation in April 1959 and March 1960, respectively. Both of these units are capable of swinging from an overnight minimum of 40 MW to their rated maximum capacity during peak load hours. This facility also has

a 23 MW gas turbine generator and a 13 MW gas turbine generator. Both of these units provide peaking service and commenced commercial operation in July 1967.

Greens Bayou. Our Greens Bayou facility is a gas and oil-fired cyclic and peaking facility located northeast of Houston. This plant consists of one 406 MW steam turbine unit, three 54 MW gas turbine units and three 64 MW gas turbine units and has an aggregate net generating capacity of 760 MW. The 406 MW steam turbine unit provides cyclic service and was placed in commercial service in June 1973. The six gas turbine units provide peaking service and were placed in commercial service in December 1976.

Webster. Our Webster facility is a gas-fired cyclic and peaking facility located southeast of Houston between the towns of Webster and League City. This plant has two units with an aggregate net generating capacity of 387 MW. One of these units is a 374 MW steam unit for cyclic service that was placed in service in May 1965 and the other is a 13 MW gas turbine for peaking service that was placed in commercial operation in July 1967.

Deepwater. Our Deepwater facility is a gas-fired cyclic facility located in southeastern Harris County, Texas. This facility consists of a 174 MW steam unit that commenced commercial operation in 1955 and underwent a life extension and conversion for cyclic operation in 1992.

H.O. Clarke. Our H.O. Clarke facility is a gas-fired peaking facility located in Houston that began operation in 1943. This plant currently consists of six simple-cycle air-cooled gas turbine generating units with an aggregate net generating capacity of 78 MW that were placed in service in June 1968.

Recent Plant Mothballing

In October 2002, we announced our plan to temporarily remove from service, or "mothball," approximately 3,400 MW of our gas-fired generating units through at least May 2003. We decided to mothball these units because of unfavorable market conditions in the ERCOT market, including a surplus of generating capacity and a lack of bids for the output of these units in our previous capacity auctions. In connection with our plan, the ERCOT ISO has determined that the mothballed units are not required for system reliability reasons through May 2003.

The mothballed units represent approximately a third of our total gas-fired generating capacity. The capacity to be mothballed includes all 2,213 MW of capacity at our P.H. Robinson facility, 229 MW of capacity at our T.H. Wharton facility, 406 MW of capacity at our Greens Bayou facility, 374 MW of capacity at our Webster facility and all 174 MW of capacity at our Deepwater facility. Based upon the results of our recent capacity auctions, we will return some or all of the mothballed facilities to service during the summer of 2003.

In connection with the decision to mothball 3,400 MW of our gas-fired generating units, we extended a voluntary early retirement package in November 2002 which was accepted by 94 of our employees. We do not believe the cost of this package will have a material impact on our results of operations, financial condition or cash flows.

South Texas Project

General. The South Texas Project is one of the largest nuclear powered generating facilities in the United States based on total MW of net generating capacity. This facility is located near Bay City, Texas and consists of two 1,250 MW generating units, the first of which commenced operation in August 1988 and the second in June 1989. We own a 30.8% interest in the South Texas Project and bear a corresponding 30.8% share of the capital and operating costs associated with the project. The South Texas Project is owned as a tenancy in common among us and three other co-owners. Each co-owner retains its undivided ownership interest in the two nuclear-fueled generating units and the electrical output from those units. We and the other three co-owners organized STP Nuclear Operating Company (STPNOC) to operate and maintain the South Texas Project. STPNOC is managed by a board of directors comprised of one director appointed by each of the co-owners, along with the chief executive officer of STPNOC.

The two South Texas Project generating units operate under licenses granted by the Nuclear Regulatory Commission (NRC) that expire in 2027 and 2028. These licenses could potentially be extended for additional twenty-year terms if the project satisfies NRC requirements.

Beginning in September 2002, an outage was commenced for one of the generating units at the South Texas Project to replace its steam generators with a model that is less susceptible to tube cracking. We expect this change will restore the design life of the unit and increase the potential for an extension of the South Texas Project's license. This unit was briefly returned to service in December 2002. However, as a result of certain non-safety related mechanical failures, the unit was removed from service in December 2002 and is expected to return to service in the first quarter of 2003. The steam generators in the other generating unit at the plant were replaced in the spring of 2000.

Decommissioning Trust. CenterPoint Houston has been authorized to collect $2.9 million per year from customers using its transmission and distribution services and is obligated to deposit the amount collected into an external trust created to fund our 30.8% share of the decommissioning costs for the South Texas Project. As of December 31, 2002, the amount in the external trust established to fund our 30.8% interest was $163 million.

In July 1999, an outside consultant estimated our 30.8% share of the decommissioning costs to be approximately $363 million in 1998 dollars. The consultant's calculation of decommissioning costs for financial planning purposes used the "DECON" methodology, one of the three alternatives acceptable to the NRC, and assumed deactivation of the project's two generating units upon the expiration of their 40-year operating licenses. The DECON methodology involves removal of all radioactive material from the site following permanent shutdown. The facility operator may then have unrestricted use of the site with no further requirement for a license. The consultant's calculation also assumed that the remainder of the plant systems and structures on site, not previously removed in support of license termination, are dismantled and the site restored.

The owners of the South Texas Project must provide a report on the status of decommissioning funding to the NRC every two years. The report compares external trust funding levels to minimum decommissioning amounts calculated in accordance with NRC requirements. We first determine our decommissioning cost estimate by escalating the NRC's estimated decommissioning cost of $105 million per unit, expressed in 1986 dollars, for the effects of inflation between 1986 and the recent year-end and then multiplying by 30.8% to reflect our share of each unit of the South Texas Project. We then use this estimate to determine the minimum required level of funding as of the most recent year-end. The calculation of the NRC minimum funding level reflects that funding of the external trusts occurs over the operating lives of the generating units. Therefore, the minimum funding level is generally less than the estimated decommissioning cost. The last report was submitted to the NRC in March 2001 and showed that, as of December 31, 2000, the aggregate NRC minimum funding level was $52.1 million. While the trust's funding levels have historically exceeded minimum NRC funding requirements, we cannot assure you that the amounts held in trust will be adequate to cover the actual decommissioning costs of the South Texas Project. These costs may vary because of changes in the assumed date of decommissioning and changes in regulatory requirements, technology and costs of labor, materials and equipment.

The investment of the funds in the external trust is managed in accordance with applicable laws and regulations and by a committee composed of our representatives and representatives of CenterPoint Energy. Pursuant to the terms of an agreement between Reliant Energy and Reliant Resources and the applicable NRC regulations, the responsibility for the decommissioning trust transferred to us at the time of Reliant Energy's corporate restructuring. In the event that funds from the trust are inadequate to decommission the facilities, CenterPoint Houston will be required to collect through rates or other authorized charges all additional amounts required to fund our obligations relating to the decommissioning of the South Texas Project. CenterPoint Energy is contractually obligated to indemnify us from and against any obligations relating to the decommissioning not otherwise satisfied through collections by CenterPoint Houston. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trust, the excess will be refunded to the rate payers of CenterPoint Houston or its successor.

Technical Services and Support Facilities

We have a central support facility that we use to support our generation facilities and refer to as our "EDC facility." This facility includes office space, a maintenance shop, a chemical lab, a warehouse facility and a fleet maintenance garage. Reliant Resources leases a portion of this facility from us.

Under our technical services agreement with Reliant Resources, it is obligated to provide engineering and technical support services and certain environmental, safety and industrial health services to support the operation and maintenance of our facilities. Reliant Resources is also obligated to provide systems, technical, programming and consulting support services and hardware maintenance, excluding plant-specific hardware, necessary to provide generation system planning, dispatch, and settlement and communication with the ERCOT ISO. We paid Reliant Resources approximately $28.3 million for providing these services during 2002.

Fuel Supplies

We rely primarily on natural gas, coal, lignite and uranium to fuel our generation facilities. The fuel mix of our generating portfolio, based on actual fuel usage during 2002, was approximately 60% coal and lignite, 28% natural gas, and 12% nuclear for the year 2002. As of December 31, 2002, the fuel mix of our generating portfolio based on the capacity of our facilities was approximately 66% natural gas, 29% coal and lignite and 5% nuclear. Based on our current assumptions regarding the cost and availability of fuel, plant operation schedules, load growth, load management and the impact of environmental regulations, we do not expect the mix of fuel used by our generating portfolio will vary materially during 2003 from prior levels. As a result of new air emissions standards imposed by federal and state law, we anticipate having higher levels of plant maintenance in 2003 and subsequent years associated with the installation of environmental equipment. These factors could affect the mix of our future fuel usage.

As a result of the Texas electric restructuring law, most of our energy sales are now based on generation capacity entitlement auctions. Successful bidders in these auctions are able to dispatch energy from their entitlements within specified operational constraints. Under the terms of the capacity auctions, successful bidders are required to make energy payments to cover a variety of charges related to the fuel and ancillary services scheduled through the auctioned entitlements.

Natural Gas

We have long-term natural gas supply contracts with several suppliers. Substantially all of our long-term contracts contain pricing provisions based on fluctuating spot market prices. In 2002, we purchased approximately 60% of our natural gas requirements under these long-term contracts, including 42% under a contract with Kinder Morgan Texas Pipelines, Inc. Our contract with Kinder Morgan has expired. However, we have a letter of intent to execute a new long-term contract with Kinder Morgan in the first quarter of 2003. We purchased the remaining 40% of our natural gas requirements in 2002 on the spot market. Based on current market conditions, we believe we will be able to replace the supplies of natural gas covered under our long-term contracts when they expire with gas purchased on the spot market or under new long-term or short-term contracts. Our natural gas consumption and cost information for 2002 was as follows:

2002 average daily consumption	385 Bbtu(1)
2002 peak daily consumption	1,113 Bbtu
2002 average cost of natural gas	$3.32 per MMBtu(2)

(1) Billion British thermal units, or "Bbtu."

(2) Compared to $4.23 per million British thermal units, or "MMBtu," in 2001 and $3.98 per MMBtu in 2000.

We lease gas storage facilities capable of storing 6.3 billion cubic feet of natural gas, of which 4.2 billion cubic feet is working capacity. We use these storage facilities to assist us in:

- managing the volatility of the gas requirements of our generating facilities;
- meeting the gas requirements of our generating facilities during periods of inadequate gas supplies; and
- managing our gas-related costs.

Our natural gas requirements are generally more volatile than our other fuel requirements because we use natural gas to fuel our intermediate, cyclic and peaking facilities and other more economical fuels to fuel our base-load facilities. Since our intermediate and peaking facilities are dispatched to meet the variations of demand for electricity, our gas requirements are highly variable, on both an hour-to-hour and day-to-day basis. Although natural gas supplies have been sufficient in recent years to supply our generating portfolio, available supplies are subject to potential disruption due to weather conditions, transportation constraints and other events. As a result of these factors, supplies of natural gas may become unavailable from time to time or prices may increase rapidly in response to temporary supply constraints or other factors.

Coal and Lignite

In 2002, we purchased approximately 80% of the fuel requirements for our four coal-fired generating units at our W.A. Parish facility under two fixed-quantity long-term supply contracts scheduled to expire in 2010 and 2011. The price for coal was fixed under the first contract through the end of 2002, after which the price is tied to spot market prices. The price for coal under the second contract was approximately three times greater than the spot market prices for coal as of December 31, 2002. The second contract does not contemplate future prices being tied to spot market prices. The terms of this contract result from the market conditions in effect during the 1970's when the contract was entered into, including shortages of natural gas supplies, increased demand for low sulfur coal as a result of new environmental regulations and uncertainty regarding the future availability of long-term sources of coal supply. The energy payments we collect for capacity entitlements with underlying coal-fired capacity are based on a pre-established price based on the Texas Utility Commission's forecasted fuel costs, which incorporate our expected fuel costs under these long-term coal supply contracts. We purchase our remaining coal requirements for our W.A. Parish facility under short-term contracts. Despite the higher coal prices under these long-term contracts, our fuel costs associated with delivering energy from our coal-fired facilities are, based on recent natural gas prices, significantly lower than the fuel costs associated with delivering energy from our gas-fired facilities. We have long-term rail transportation contracts with Burlington Northern Santa Fe Railroad and the Union Pacific Railroad Company to transport coal to our W.A. Parish facility.

We obtain the lignite used to fuel the two generating units of our Limestone facility from a surface mine adjacent to the facility. We own the mining equipment and facilities and a portion of the lignite reserves located at the mine. Mining operations are conducted by the owner of the remaining lignite reserves. In the past, we have obtained our lignite requirements under a long-term contract on a cost-plus basis. Since July 2002, we have obtained our lignite requirements under an amended long-term contract with the owner/operator at a fixed price determined annually that is expected to result in a cost of generation at the Limestone facility equivalent to the cost of generating with low sulfur Western coal. We expect the lignite reserves will be sufficient to provide all of the lignite requirements of this facility through 2015. The energy payments we collect for capacity entitlements with underlying lignite-fired capacity are based on a pre-established price based on the Texas Utility Commission's forecasted fuel costs, which incorporate our expected costs under our lignite supply contract.

During 2002, we conducted a successful test burn of Wyoming coal at the Limestone facility. We anticipate using a blend of lignite and Wyoming coal to fuel our Limestone facility beginning in 2003 as a component of our oxides of nitrogen (NOx) control strategy. A fuel unloading and handling system was installed at the Limestone facility to accommodate the delivery of Wyoming coal. We expect that we will obtain Wyoming coal through spot and long-term market priced contracts. Our Limestone facility is connected with the Burlington Northern Santa Fe Railroad.

Nuclear

The South Texas Project satisfies its fuel supply requirements by acquiring uranium concentrates, converting uranium concentrates into uranium hexafluoride, enriching uranium hexafluoride, and fabricating nuclear fuel assemblies. We are party to a number of contracts covering a portion of the fuel requirements of the South Texas Project for uranium, conversion services, enrichment services and fuel fabrication. Other than a fuel fabrication agreement that extends for the life of the South Texas Project, these contracts have varying expiration dates, and most are short to medium term (less than seven years). We believe that sufficient capacity for nuclear fuel supplies and processing exists to permit normal operations of the South Texas Project's nuclear powered generating units. The energy payments we collect for capacity entitlements with underlying nuclear capacity are based on a pre-established price based on the Texas Utility Commission's forecasted costs, which incorporate our expected costs under these contracts.

Fuel Pipeline

We own an 87-mile fuel pipeline that can transport either fuel oil or gas. As part of our system, we own over five million barrels of oil storage capacity that can supply fuel oil to our Cedar Bayou, Greens Bayou, S.R. Bertron and T.H. Wharton plants. For natural gas supply, our pipeline is connected to six of our generation facilities and is interconnected with several of our suppliers. Our pipeline provides us with added flexibility in managing the fuel supply requirements of our generation facilities.

CPS Joint Operating Agreement

We have a joint operating agreement with the City Public Service Board of San Antonio (CPS) to jointly dispatch our portfolio of generating units with CPS' portfolio of 4,823 MW of generating capacity as a joint operating system to meet our combined obligations. The combined system includes approximately 19,000 MW of generating capacity and provides us with added economies of scale and production cost savings. A large portion of the benefit of joint operations is due to San Antonio's significant amount of capacity at its coal-fired generation facilities. We share the fuel cost savings realized under the agreement with the City of San Antonio. We currently share the cost savings benefits equally with CPS. The current agreement with CPS expires in 2009. Both parties are permitted to sell their capacity outside of the joint operating system if it is economically prudent to do so, in which case the parties would lose the agreement's cost savings benefits with respect to those sales. The capacity of CPS' generating facilities covered by the joint operating agreement is not included in the capacity auctions described under "Capacity Auctions and Opportunity Sales" above.

Competition

The ERCOT market is highly competitive. We have approximately 80 competitors which include generation companies affiliated with Texas-based utilities, independent power producers, municipal or co-operative generators and wholesale power marketers. These competitors compete with us and each other by buying and selling wholesale power in the ERCOT market, entering into bilateral contracts and/or selling to aggregated retail customers. As of December 31, 2002, our facilities provided less than 20% of the aggregate net generating capacity serving the ERCOT market. Our competition is based primarily on price but we also may compete based on product flexibility. A number of our competitors are building efficient, combined cycle power plants that are generally not able to provide the operational flexibility, ancillary services and fuel risk mitigation that our large diversified portfolio of generating facilities can provide. In addition, we believe that there may be significant excess generating capacity constructed in the ERCOT market over the next several years. This overbuilding could result in lower prices for wholesale power in the ERCOT market. For more information regarding this trend and other competitive factors in the ERCOT market, please read "The ERCOT Market" above.

Customers

Since January 1, 2002, we have sold power to wholesale purchasers, including retail electric providers, at unregulated rates through our capacity auctions. In addition to retail electric providers, our customers in the ERCOT market include municipal utilities, electric co-operatives, power trading organizations and other power generating companies. We are also a significant provider to the ancillary services market operated by the ERCOT ISO. We expect our mix of customers and the mix of participants will change significantly as the ERCOT market evolves from one dominated by vertically integrated electric utilities to one with utility-affiliated retail electric providers, new-entrant retail electric providers, a greater participation by unregulated energy merchants, and more generation capacity from independent generation companies. Sales to Reliant Resources represented approximately 66% of Texas Genco's total revenues in 2002.

Insurance

General

We carry insurance coverage consistent with companies engaged in similar commercial operations with similar properties. Our insurance coverage includes:

- public liability insurance, covering liabilities to third parties for bodily injury and property damage resulting from our operations;
- automobile liability insurance, for all owned, non-owned and hired vehicles, covering liabilities to third parties for bodily injury and property damage; and
- property insurance, subject to replacement cost of insured real and personal property, including coverage for boiler and machinery breakdowns, earthquake and flood damage, subject to certain sublimits.

We also maintain substantial excess liability insurance coverage above the established primary limits for public general liability and automobile liability insurance. Limits and deductibles are comparable to those carried by other electric generation companies of similar size. However, our insurance policies are subject to certain limits and deductibles and do not include business interruption coverage. Adequate insurance coverage may not be available in the future on commercially reasonable terms. Also, the insurance proceeds received for any loss of or any damage to any of our generation facilities may not be sufficient to restore the loss or damage without negative impact on our financial condition and results of operations. The costs of our insurance coverage have increased significantly during the past year and may continue to increase in the future.

Nuclear

We and the other owners of the South Texas Project maintain nuclear property and nuclear liability insurance coverage as required by law and periodically review available limits and coverage for additional protection. The owners of the South Texas Project currently maintain $2.75 billion in property damage insurance coverage, which is above the legally required minimum, but is less than the total amount of insurance currently available for such losses.

Under the Price Anderson Act, the maximum liability to the public of owners of nuclear power plants was $9.3 billion as of December 31, 2002. Owners are required under the Price Anderson Act to insure their liability for nuclear incidents and protective evacuations. We and the other owners of the South Texas Project currently maintain the required nuclear liability insurance and participate in the industry retrospective rating plan under which the owners of the South Texas Project are subject to maximum retrospective assessments in the aggregate per incident of up to $88 million per reactor. The owners are jointly and severally liable at a rate not to exceed $10 million per incident per year. In addition, the security procedures at this facility have recently been enhanced to provide additional protection against terrorist attacks.

We cannot assure you that all potential losses or liabilities associated with the South Texas Project will be insurable, or that the amount of insurance will be sufficient to cover them. Any substantial losses not covered by insurance would have a material adverse effect on our financial condition, results of operations and cash flows.

Background of the Distribution of Texas Genco Shares

Reliant Energy's Business Separation Plan

The Texas electric restructuring law requires the restructuring of electric utilities in Texas in order to separate their power generation, transmission and distribution, and retail electric businesses into separate units. In March 2001, the Texas Utility Commission approved a business separation plan for Reliant Energy involving the separation of Reliant Energy's generation, transmission and distribution, and retail businesses into three separate companies. Effective August 31, 2002, Reliant Energy consummated a restructuring transaction in accordance with its business separation plan in which it, among other things:

- conveyed all of its electric generating facilities to us;
- became a subsidiary of CenterPoint Energy; and
- converted into a limited liability company named CenterPoint Energy Houston Electric, LLC, which we refer to as "CenterPoint Houston."

Although our portfolio of generating facilities was formerly owned by the unincorporated electric utility division of Reliant Energy, for convenience, we describe our business in this report as if we had owned and operated our generation facilities prior to the date they were conveyed to us. The book value of the net assets conveyed to us by Reliant Energy on August 31, 2002 was approximately $2.8 billion.

CenterPoint Houston's Stranded Cost Recovery

Under the Texas electric restructuring law, transmission and distribution utilities whose generation assets were "unbundled" pursuant to the law, including CenterPoint Houston, are entitled to recover their "stranded costs" associated with those assets. The Texas electric restructuring law defines stranded costs as the positive excess of the regulatory net book value of the utility's unbundled generation assets over the market value of those assets, after taking specified factors into account. The law allows alternate methods for establishing a market value for generation assets, including outright sale, full or partial stock market valuation and asset exchanges. Under Reliant Energy's business separation plan, Reliant Energy agreed that the fair market value of our generating assets will be determined using the partial stock market valuation method. CenterPoint Energy made the distribution in order to establish a public market value for our shares that will be used in 2004 to calculate how much CenterPoint Houston will be able to recover as stranded costs and to comply with CenterPoint Energy's contractual obligations to Reliant Resources.

Beginning in January 2004, on a schedule established by the Texas Utility Commission, investor-owned utilities in Texas may file to commence true-up proceedings. One of the purposes of the true-up proceeding for CenterPoint Energy will be to quantify the amount of stranded costs associated with our generation assets. In the proceeding, the regulatory net book value of our generating assets will be compared to the market value based on the partial stock valuation method. The resulting difference, if positive, is stranded cost that will be recoverable by CenterPoint Houston either through a transition charge, which is a non-bypassable charge assessed to CenterPoint Houston's customers, or through a securitization of such cost. Texas Genco is not entitled to receive any payment or other benefits in connection with CenterPoint Houston's recovery of stranded costs. In the true-up proceeding, the market value of our assets will be based on the average daily closing price of Texas Genco's common stock on The New York Stock Exchange for the 30 consecutive trading days chosen by the Texas Utility Commission out of the last 120 days immediately preceding the true-up filing, plus a control premium, up to a maximum of 10%, to the extent included in the valuation determination made by the Texas Utility Commission.

Reliant Resources Option

One of the objectives of Reliant Energy's business separation plan was to separate Reliant Energy's operations into two unaffiliated publicly traded companies with one company, CenterPoint Energy, holding Reliant Energy's regulated energy delivery businesses and the other company, Reliant Resources, holding its competitive energy services operations. As part of the business separation plan, Reliant Resources was granted an option that may be exercised between January 10, 2004 and January 24, 2004 to purchase all of the shares of Texas Genco common stock owned by CenterPoint Energy. For more information regarding the Reliant Resources Option, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Related Party Transactions — Reliant Resources Option" in Item 7 of this report.

Regulation

We are subject to regulation by various federal, state and local governmental agencies, including the regulations described below and under "The ERCOT Market," "Capacity Auctions and Opportunity Sales — State Mandated Auctions" and "Environmental Matters — Regulation" below.

Public Utility Holding Company Act of 1935

As a subsidiary of a registered public utility holding company, we are subject to a comprehensive regulatory scheme imposed by the SEC in order to protect customers, investors and the public interest. Although the SEC does not regulate rates and charges under the 1935 Act, it does regulate the structure, financing, lines of business and internal transactions of public utility holding companies and their system companies. In order to obtain financing, acquire additional public utility assets or stock, or engage in other significant transactions, we are generally required to obtain approval from the SEC under the 1935 Act.

Prior to the restructuring of Reliant Energy pursuant to its business separation plan, CenterPoint Energy and Reliant Energy obtained an order from the SEC that authorized the restructuring transactions and granted CenterPoint Energy certain authority with respect to system financing, dividends and other matters. The financing authority granted by that order will expire on June 30, 2003, and CenterPoint Energy must obtain a further order from the SEC under the 1935 Act, related, among other things, to the financing activities of CenterPoint Energy and its subsidiaries, including us, subsequent to June 30, 2003.

In a July 2002 order, the SEC limited the aggregate amount of our external borrowings to $500 million. Our ability to pay dividends is restricted by the SEC's requirement that common equity as a percentage of total capitalization must be at least 30% after the payment of any dividend. In addition, the order restricts our ability to pay dividends out of capital accounts to the extent current or retained earnings are insufficient for those dividends. Under these restrictions, we are permitted to pay dividends in excess of our current or retained earnings in an amount up to $100 million.

In 2002, CenterPoint Energy Resources Corp., a subsidiary of CenterPoint Energy, obtained authority from each state in which such authority was required to restructure in a manner that would allow CenterPoint Energy to claim an exemption from registration under the 1935 Act. CenterPoint Energy has concluded that a restructuring would not be beneficial and has elected to remain a registered holding company under the 1935 Act.

Nuclear Regulatory Commission

We are subject to regulation by the NRC with respect to the operation of the South Texas Project. This regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstrations to the NRC that plant operations meet applicable requirements are also required. The NRC has the ultimate authority to determine whether any nuclear powered generating unit may operate.

We and the other owners of the South Texas Project are required by NRC regulations to estimate from time to time the amounts required to decommission that nuclear generating facility and are required to

maintain funds to satisfy that obligation when the plant ultimately is decommissioned. CenterPoint Houston currently collects through its electric rates amounts calculated to provide sufficient funds at the time of decommissioning to discharge these obligations. Funds collected will be deposited into a nuclear decommissioning trust. The beneficial ownership in the decommissioning trust is held by us, as the licensee of the facility. While current funding levels exceed NRC minimum requirements, no assurance can be given that the amounts held in trust will be adequate to cover the actual decommissioning costs of the South Texas Project. Such costs may vary because of changes in the assumed date of decommissioning and changes in regulatory requirements, technology and costs of labor, materials and waste burial. For additional information regarding the decommissioning trust, please read "Our Generation Portfolio — South Texas Project — Decommissioning Trust" above.

Environmental Matters

Regulation

We are subject to a number of federal, state and local laws and regulations relating to the protection of the environment and the safety and health of personnel and the public. These requirements relate to a broad range of our activities, including:

- the discharge of pollutants into the air, water and soil;
- the identification, generation, storage, handling, transportation, disposal, record keeping, labeling and reporting of, and the emergency response in connection with, hazardous and toxic materials and wastes, including asbestos, associated with our operations;
- noise emissions from our facilities; and
- safety and health standards, practices and procedures that apply to the workplace and the operation of our facilities.

In order to comply with these requirements, we may need to spend substantial amounts and devote other resources from time to time to:

- construct or acquire new equipment;
- acquire permits and/or marketable allowance or other emission credits for facility operations;
- modify or replace existing and proposed equipment; and
- clean up or decommission waste disposal areas, fuel storage and management facilities, and other locations and facilities, including generation facilities.

If we do not comply with environmental requirements that apply to our operations, regulatory agencies could seek to impose on us civil, administrative and/or criminal liabilities as well as seek to curtail our operations. Under some statutes, private parties could also seek to impose upon us civil fines or liabilities for property damage, personal injury and possibly other costs.

Under the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA), owners and operators of facilities from which there has been a release or threatened release of hazardous substances, together with those who have transported or arranged for the disposal of those substances, are liable for:

- the costs of responding to that release or threatened release; and
- the restoration of natural resources damaged by any such release.

Air Emissions

NOx Reduction Program. As part of the 1990 amendments to the Federal Clean Air Act, requirements and schedules for compliance were developed for attainment of health-based standards. As part of this

process, standards for NOx emissions, a product of the combustion process associated with power generation, are being developed or have been finalized. The Texas Commission on Environmental Quality (TCEQ) standards requires reduction of emissions from our power generating units. The Texas electric restructuring law, as well as regulations adopted by TCEQ in 2001, requires substantial reductions in NOx emissions from electric generating units. We are currently installing cost-effective controls at our generating plants to comply with these requirements. As of December 31, 2002, we had invested $551 million for NOx emission controls and we are planning to make expenditures of at least $131 million in the years 2003 through 2005, with possible additional expenditures after 2005. NOx control estimates for 2006 and 2007 have not been finalized. The Texas Utility Commission has initially approved our NOx emission reduction plan in the amount of $699 million as the most cost-effective alternative in achieving compliance with applicable air quality standards for our generation facilities. In addition, we are required to fund NOx reduction projects for pipelines in East Texas at a cost of $16.2 million, which is included in the amounts described above.

The Environmental Protection Agency (EPA) has announced its determination to regulate hazardous air pollutants, including mercury, from coal-fired and oil-fired steam electric generating units under the Clean Air Act. The EPA plans to develop maximum achievable control technology (MACT) standards for these types of units as well as for turbines, engines and industrial boilers. The rulemaking for coal- and oil-fired steam electric generating units must be completed by December 2004. Compliance with the rules will be required within three years thereafter. The MACT standards that will be applicable to our units cannot be predicted at this time and may adversely impact our operations. The rulemaking for turbines is expected to be complete in August 2003 and for engines and industrial boilers in 2004. Based on the rules currently proposed, we do not anticipate a material adverse impact on our operations.

In 1998, the United States signed the United Nations Framework Convention on Climate Change (Kyoto Protocol). The Kyoto Protocol calls for developed nations to reduce their emissions of greenhouse gases. Carbon dioxide, which is a major byproduct of the combustion of fossil fuel, is considered to be a greenhouse gas. In 2002, President Bush withdrew the United States' support for the Kyoto Protocol. Since this withdrawal, Congress has explored a number of other alternatives for regulating domestic greenhouse gas emissions. If the country re-enters and the United States Senate ultimately ratifies the Kyoto Protocol and/or if the United States Congress adopts other measures for the control of greenhouse gases, any resulting limitations on power plant carbon dioxide emissions could have a material adverse impact on all fossil fuel fired facilities, including ours.

The EPA is conducting a nationwide investigation regarding the historical compliance of coal-fueled electric generating stations with various permitting requirements of the Clean Air Act. Specifically, the EPA and the U.S. Department of Justice have initiated formal enforcement actions and litigation against several other utility companies that operate these stations, alleging that these companies modified their facilities without proper preconstruction permit authority. To date, we have not received requests for information related to work activities conducted at our facilities. The EPA has not filed an enforcement action or initiated litigation in connection with our facilities. Nevertheless, any litigation, if pursued successfully by the EPA, could accelerate the timing of emission reductions currently contemplated for the facilities and result in the imposition of penalties.

In February 2001, the United States Supreme Court upheld previously adopted EPA ambient air quality standards for fine particulate matter and ozone. While attaining these new standards may ultimately require expenditures for air quality control system upgrades for our facilities, regulations establishing required controls are not expected until after 2005. Consequently, it is not possible to determine the impact on our operations at this time.

In July 2002, the White House sent to the United States Congress a Bill proposing the "Clear Skies Act of 2002" (Clear Skies Act), which is designed to achieve long-term reductions of multiple pollutants produced from fossil fuel-fired power plants. If enacted, the Clear Skies Act would target reductions averaging 70% for sulfur dioxide, NOx and mercury emissions and would create a gradually imposed market-based compliance program that would come into effect initially in 2008 with full compliance required by 2018. Fossil fuel-fired power plants owned by companies like us would be affected by the adoption of this program, or other

legislation currently pending in Congress addressing similar issues. To comply with such programs, we and other regulated entities could pursue a variety of strategies including the installation of pollution controls, the purchase of emission allowances, or the curtailment of operations.

Water

In July 2000, the EPA issued final rules for the implementation of the total maximum daily load (TMDL) program. The goal of the TMDL program is to restore waters designated as impaired by identifying and restricting the loading of pollutants contributing to the impairment. While we are not aware of any of our facilities being directly affected by the current TMDL developments, there is the potential that the establishment of TMDLs may eventually result in more stringent discharge limits in our plant discharge permits. Such limits could require our facilities to install additional water treatment facilities or equipment, modify operational practices or implement other water quality improvement measures. In October 2001, the EPA signed a final rule delaying the effective date of the TMDL rule until April 30, 2003. In December 2002, the EPA published a proposal rulemaking that would withdraw the July 2000 rule.

In April 2002, the EPA proposed rules under Section 316(b) of the Clean Water Act relating to the design and operation of cooling water intake structures. This proposal is the second of three current phases of rulemaking dealing with Section 316(b) and generally would affect existing facilities that use significant quantities of cooling water. Under the amended court deadline, the EPA is to issue final rules for these Phase II facilities by February 2004. While the requirements of the final rule cannot be predicted at this time, we may be required to incur significant capital expenditures. We anticipate that substantial comments and, if necessary, litigation will be filed by affected parties to attempt to achieve an acceptable final regulation.

The EPA and the State of Texas periodically update water quality standards in response to new toxicological data and the development of enhanced analytical techniques that allow lower detection levels. The lowering of water quality criteria for parameters such as arsenic, mercury and selenium could affect generating facility discharge limitations and require our facilities to install additional treatment equipment.

Asbestos

As a result of their age, many of our facilities contain significant amounts of asbestos insulation, other asbestos-containing materials and lead-based paint. Existing state and federal rules require the proper management and disposal of these potentially toxic materials. We have developed a management plan that includes proper maintenance of existing non-friable asbestos installations, and removal and abatement of asbestos containing materials where necessary because of maintenance, repairs, replacement or damage to the asbestos itself. We have planned for the proper management, abatement and disposal of asbestos and lead-based paint at our facilities.

Our facilities are the subject of a number of lawsuits filed by a large number of individuals who claim injury due to exposure to asbestos while working at sites along the Texas Gulf Coast. Most of these claimants have been third party workers who participated in construction of various industrial facilities, including power plants, and some of the claimants have worked at locations owned by us. We anticipate that additional claims like those received may be asserted in the future, and we intend to continue our practice of vigorously contesting claims that we do not consider to have merit. Although their ultimate outcome cannot be predicted at this time, we do not believe, based on our experience to date, that these matters, either individually or in the aggregate, will have a material adverse effect on our financial position, results of operations or cash flows.

Employees

As of December 31, 2002, we employed approximately 1,639 people. Of these employees, approximately 1,102 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers Local 66 that extends through September 2003.

EXECUTIVE OFFICERS
(As of March 1, 2003)

Name	Age	Position
David M. McClanahan	53	Chairman and Director
David G. Tees	58	President, Chief Executive Officer and Director
Scott E. Rozzell	53	Executive Vice President, General Counsel and Corporate Secretary
Gary L. Whitlock	53	Executive Vice President and Chief Financial Officer
James S. Brian	55	Senior Vice President and Chief Accounting Officer
Joseph B. McGoldrick	49	Corporate Vice President, Strategic Planning

David M. McClanahan is the Chairman of our board of directors. Mr. McClanahan has also served on the board of directors and as the President and Chief Executive Officer of CenterPoint Energy since September 2002. He served as the Vice Chairman of Reliant Energy from October 2000 to September 2002 and as President and Chief Operating Officer of Reliant Energy's Delivery Group since 1999. He also served as the President and Chief Operating Officer of Reliant Energy HL&P from 1997 to 1999. He has served in various other executive capacities with Reliant Energy since 1986. He previously served as Chairman of the Board of Directors of ERCOT and Chairman of the Board of the University of St. Thomas. He currently serves on the boards of the Edison Electric Institute, American Gas Association and Interstate Natural Gas Association of America.

David G. Tees is our President and Chief Executive Officer and a member of our board of directors. He served as Senior Vice President, Generation Operations of Reliant Energy from 1998 through August 2002. He also served as Vice President of Energy Production of Reliant Energy HL&P from 1986 through 1998. Mr. Tees has also served on the executive committee of the Edison Electric Institute Energy Supply Subcommittee and presently represents CenterPoint Energy as a Research Advisory Committee Member of the Electric Power Research Institute and is the Chairman of the Board of the STP Nuclear Operating Company.

Scott E. Rozzell is our Executive Vice President, General Counsel and Corporate Secretary. Mr. Rozzell has also served as the Executive Vice President, General Counsel and Corporate Secretary of CenterPoint Energy since September 2002. He served as Executive Vice President and General Counsel of the Delivery Group of Reliant Energy from March 2001 to September 2002. Prior to joining Reliant Energy, Mr. Rozzell was a senior partner in the law firm of Baker Botts L.L.P.

Gary L. Whitlock is our Executive Vice President and Chief Financial Officer. Mr. Whitlock has also served as the Executive Vice President and Chief Financial Officer of CenterPoint Energy since September 2002. He served as Executive Vice President and Chief Financial Officer of the Delivery Group of Reliant Energy from July 2001 to September 2002. Mr. Whitlock served as the Vice President, Finance and Chief Financial Officer of Dow AgroSciences, a subsidiary of The Dow Chemical Company from 1998 to 2001.

James S. Brian is our Senior Vice President and Chief Accounting Officer. Mr. Brian has also served as the Senior Vice President and Chief Accounting Officer of CenterPoint Energy since August 2002. He served as Senior Vice President, Finance and Administration of the Delivery Group of Reliant Energy from 1999 to August 2002, and as Vice President and Chief Financial Officer of Reliant Energy HL&P from 1997 to 1999. He has served in various executive capacities with Reliant Energy since 1983.

Joseph B. McGoldrick is our Corporate Vice President, Strategic Planning. Mr. McGoldrick has also served as Corporate Vice President, Strategic Planning of CenterPoint Energy since September 2002. He served as Corporate Vice President, Strategic Planning of the Delivery Group of Reliant Energy from November 2001 to August 2002. He served as Senior Vice President, Finance & Administration for Reliant Energy Retail from 2000 to 2001. He has served in various executive capacities with Reliant Energy since 1993.

RISK FACTORS

Market Risks

Our revenues and results of operations are impacted by market risks that are beyond our control.

We sell electric generation capacity, energy and ancillary services in the ERCOT market. Under the Texas electric restructuring law, we and other power generators in Texas are not subject to traditional cost-based regulation and therefore may sell electric generation capacity, energy and ancillary services to wholesale purchasers at prices determined by the market. As a result, we are not guaranteed any rate of return on our capital investments through mandated rates, and our revenues and results of operations depend, in large part, upon prevailing market prices for electricity in the ERCOT market. Market prices for electricity, generation capacity, energy and ancillary services may fluctuate substantially. Our gross margins are primarily derived from the sale of capacity entitlements associated with our large, solid fuel base-load generating units, including our Limestone and W. A. Parish facilities and our interest in the South Texas Project. The gross margins generated from payments associated with the capacity of these units are directly impacted by natural gas prices. Since the fuel costs for our base-load units are largely fixed under long-term contracts, they are generally not subject to significant daily and monthly fluctuations. Because natural gas is the marginal fuel for facilities serving the ERCOT market during most hours, gas prices have a significant influence on the price of electric power. As a result, the price customers are willing to pay for entitlements to our solid fuel-fired base-load capacity generally rises and falls with natural gas prices.

Market prices in the ERCOT market may also fluctuate substantially due to other factors. Such fluctuations may occur over relatively short periods of time. Volatility in market prices may result from:

- oversupply or undersupply of generation capacity;
- power transmission or fuel transportation constraints or inefficiencies;
- weather conditions;
- seasonality;
- availability and market prices for natural gas, crude oil and refined products, coal, enriched uranium and uranium fuels;
- changes in electricity usage;
- additional supplies of electricity from existing competitors or new market entrants as a result of the development of new generation facilities or additional transmission capacity;
- illiquidity in the ERCOT market;
- availability of competitively priced alternative energy sources;
- natural disasters, wars, embargoes, terrorist attacks and other catastrophic events; and
- federal and state energy and environmental regulation and legislation.

There is currently a surplus of generating capacity in the ERCOT market and we expect the market for wholesale power to be highly competitive.

The reserve margin in the ERCOT market has exceeded 20% since 2001, and the Texas Utility Commission and the ERCOT ISO have forecasted the reserve margin for 2003 to continue to exceed 20%. The commencement of commercial operation of new facilities in the ERCOT market will increase the competitiveness of the wholesale power market, which could have a material adverse effect on our business, results of operations, financial condition and cash flows and the market value of our assets.

Our competitors include generation companies affiliated with Texas-based utilities, independent power producers, municipal and co-operative generators and wholesale power marketers. The unbundling of vertically integrated utilities into separate generation, transmission and distribution and retail businesses

pursuant to the Texas electric restructuring law could result in a significant number of additional competitors participating in the ERCOT market. Some of our competitors may have greater financial resources, lower cost structures, more effective risk management policies and procedures, greater ability to incur losses, greater potential for profitability from ancillary services, or greater flexibility in the timing of their sale of generating capacity and ancillary services than we do.

We are subject to operational and market risks associated with our capacity auctions.

We are obligated to sell substantially all of our available capacity and related ancillary services through 2003 pursuant to capacity auctions. In these auctions, we sell firm entitlements on a forward basis to capacity and ancillary services dispatched within specified operational constraints. Although we have reserved a portion of our aggregate net generation capacity from our capacity auctions for planned or forced outages at our facilities, unanticipated plant outages or other problems with our generation facilities could result in our firm capacity and ancillary services commitments exceeding our available generation capacity. As a result, we could be required to obtain replacement power from third parties in the open market to satisfy our firm commitments, that could result in significant additional costs. In addition, an unexpected outage at one of our lower cost facilities could require us to run one of our higher cost plants in order to satisfy our obligations even though the energy payments for the dispatched power are based on the cost of our lower-cost facilities.

We sell capacity entitlements in state mandated auctions and in our other contractually mandated auctions. The mechanics, regulations and agreements governing our capacity auctions are complex, and the auction process in which we sell entitlements to our capacity is relatively new. The state mandated auctions require, among other things, our capacity entitlements to be sold in pre-determined amounts. The characteristics of the capacity entitlements we sell in state mandated auctions are defined by rules adopted by the Texas Utility Commission and therefore cannot be changed to respond to market demands or operational requirements without approval by the Texas Utility Commission.

If the ERCOT market does not function in the manner contemplated by the Texas electric restructuring law, our business prospects, results of operations, financial condition and cash flows could be adversely impacted.

The initiatives under the Texas electric restructuring law have had a significant impact on the nature of the electric power industry in Texas and the manner in which participants in the ERCOT market conduct their business. These changes are ongoing and we cannot predict the future development of the ERCOT market or the ultimate effect that this changing regulatory environment will have on our business. Some restructured markets in other states have recently experienced supply problems and extreme price volatility. If the ERCOT market does not function as planned once the deregulation initiatives called for by the Texas electric restructuring law have taken their full effect, our results of operations, financial condition and cash flows could be adversely affected. In addition, any market failures could lead to revisions or reinterpretations of the Texas electric restructuring law, the adoption of new laws and regulations applicable to us or our facilities and other future changes in laws and regulations that may have a detrimental effect on our business.

As part of the transition to retail competition in Texas, the ERCOT market has changed from operating with multiple control areas, each managed by one of the utilities in the state, to a single control area managed by the ERCOT ISO. The ERCOT ISO is responsible for maintaining reliable operations of the bulk electric power supply system in the new combined control area. If the ERCOT ISO is unable to successfully manage these functions, the ERCOT market may not operate properly and our results of operations could be adversely affected. In addition, the ERCOT ISO may impose or the Texas Utility Commission may require price limitations, bidding rules and other mechanisms that could impact wholesale prices in the ERCOT market and the outcomes of our capacity auctions.

Operating Risks

The operation of our power generation facilities involves risks that could adversely affect our revenues, costs, results of operations and cash flows.

General. We are subject to various risks associated with operating our power generation facilities, any of which could adversely affect our revenues, costs, results of operations, financial condition and cash flows. These risks include:

- operating performance below expected levels of output or efficiency;
- breakdown or failure of equipment or processes;
- disruptions in the transmission of electricity;
- shortages of equipment, material or labor;
- labor disputes;
- fuel supply interruptions;
- limitations that may be imposed by regulatory requirements, including, among others, environmental standards;
- limitations imposed by the ERCOT ISO;
- violations of permit limitations;
- operator error; and
- catastrophic events such as fires, hurricanes, explosions, floods, terrorist attacks or other similar occurrences.

A significant portion of our facilities was constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to keep it operating at high efficiency and to meet regulatory requirements. This equipment is also likely to require periodic upgrading and improvement. Any unexpected failure to produce power, including failure caused by breakdown or forced outage, could result in reduced earnings.

The cost of repairing damage to our facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events may adversely impact our results of operations, financial condition and cash flows. The occurrence or risk of occurrence of future terrorist activity may impact our results of operations and financial condition in unpredictable ways. These actions could also result in adverse changes in the insurance markets and disruptions of power and fuel markets. In addition, our power generation facilities and fuel supply could be directly or indirectly harmed by future terrorist activity. The occurrence or risk of occurrence of future terrorist attacks or related acts of war could also adversely affect the United States economy. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues and margins and limit our future growth prospects. Also, these risks could cause instability in the financial markets and adversely affect our ability to access capital.

We employ experienced personnel to maintain and operate our facilities and carry insurance to mitigate the effects of some of the operating risks described above. Our insurance policies, however, are subject to certain limits and deductibles and do not include business interruption coverage. Should one or more of the events described above occur, revenues from our operations may be significantly reduced or our costs of operations may significantly increase.

We rely on power transmission facilities that we do not own or control and are subject to transmission constraints within the ERCOT market. If these facilities fail to provide us with adequate transmission capacity, we may not be able to deliver wholesale electric power to our customers and we may incur additional costs.

We depend on transmission and distribution facilities owned and operated by our affiliate, CenterPoint Houston, and on transmission and distribution systems owned by others to deliver the wholesale electric power we sell from our power generation facilities to our customers, who in turn deliver power to the end users. If transmission is disrupted, or if transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale electric energy may be adversely impacted.

The single control area of the ERCOT market is currently organized into four congestion zones, referred to as the North, South, West and Houston zones. These congestion zones are determined by physical constraints on the ERCOT transmission system that make it difficult or impossible at times to move power from a zone on one side of the constraint to the zone on the other side of the constraint. All but two of our facilities are located in the Houston congestion zone. Our Limestone facility is located in the North congestion zone and the South Texas Project is located in the South congestion zone. We sell a portion of the entitlements offered in our state mandated auctions to customers located in congestion zones other than the Houston zone. Transmission congestion between these zones could impair our ability to schedule power for transmission across zonal boundaries, which are defined by the ERCOT ISO, thereby inhibiting our efforts to match our facility scheduled outputs with our customer scheduled requirements.

The ERCOT ISO has instituted rules that directly assign congestion costs to the parties causing the congestion. Therefore, power generators participating in the ERCOT market could be liable for the congestion costs associated with transferring power between zones. We schedule our anticipated requirements based on our own forecasted needs, which rely in part on demand forecasts made by our customers. These forecasts may prove to be inaccurate. We could be deemed responsible for congestion costs if we schedule delivery of power between congestion zones during times when the ERCOT ISO expects congestion to occur between the zones. If we are liable for congestion costs, our financial results could be adversely affected. For more information about the ERCOT market, please read "Our Business — ERCOT Market Framework" above.

Our results of operations, financial condition and cash flows could be adversely impacted by a disruption of our fuel supplies.

We rely primarily on natural gas, coal, lignite and uranium to fuel our generation facilities. We purchase our fuel from a number of different suppliers under long-term contracts and on the spot market. Under our capacity auctions, we sell firm entitlements to capacity and ancillary services. Therefore, any disruption in the delivery of fuel could prevent us from operating our facilities to meet our auction commitments, which could adversely affect our results of operations, financial condition and cash flows.

Delivery of natural gas to each of our natural gas-fired facilities typically depends on the natural gas pipelines or distributors for that location. As a result, we are subject to the risk that a natural gas pipeline or distributor may suffer disruptions or curtailments in our ability to deliver natural gas to it or that the amounts of natural gas we request are curtailed. These disruptions or curtailments could adversely affect our ability to operate our natural gas-fired generating facilities. We lease gas storage facilities capable of storing approximately 6.3 billion cubic feet of natural gas, of which 4.2 billion cubic feet is working capacity.

We purchase coal from a limited number of suppliers. Generally, we seek to maintain average coal reserves sufficient to operate our coal-fired facilities for 30 days. We also have long-term rail transportation contracts with two rail transportation companies to transport coal to our coal-fired facilities. Any extended disruption in our coal supply, including those caused by transportation disruptions, adverse weather conditions, labor relations or environmental regulations affecting our coal suppliers, could adversely affect our ability to operate our coal-fired facilities. We are also exposed to the risk that suppliers that have agreed to provide us with fuel could breach their obligations. Should these suppliers fail to perform, we may be forced to enter into alternative arrangements at then-current market prices. As a result, our results of operations, financial condition and cash flows could be adversely affected.

To date, we have sold a substantial portion of our auctioned capacity entitlements to subsidiaries of Reliant Resources. Accordingly, our results of operations, financial condition and cash flows could be adversely affected if Reliant Resources declined to participate in our future auctions or failed to make payments when due under Reliant Resources' purchased entitlements.

By participating in our contractually mandated auctions, subsidiaries of Reliant Resources purchased entitlements to 63% of the aggregate 2002 capacity and 58% of the aggregate 2003 capacity that we sold to date through our capacity auctions. Reliant Resources has made these purchases either through the exercise of its contractual rights to purchase 50% of the entitlements we auction in our contractually mandated auctions or through the submission of bids. In the event Reliant Resources declined to participate in our future auctions or failed to make payments when due, our results of operations, financial condition and cash flows could be adversely affected. In this regard, Reliant Resources has reported that it is facing large maturities of debt over the next year, and its securities ratings are now below investment grade.

We may incur substantial costs and liabilities as a result of our ownership of nuclear facilities.

We own a 30.8% interest in the South Texas Project, a nuclear powered generation facility. As a result, we are subject to the risks associated with the ownership and operation of nuclear facilities. These risks include:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives;

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines, shut down a unit, or both, depending upon our assessment of the severity of the situation, until compliance is achieved. Any revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants. In addition, although we have no reason to anticipate a serious nuclear incident at the South Texas Project, if an incident did occur, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Other Risks

Our historical financial results covering periods prior to 2002 represent our results as part of an integrated utility operating in a regulated market and are not representative of our results as a separate company operating in the recently deregulated ERCOT market. Consequently, our future financial condition and results of operations are likely to vary materially from the financial condition and results of operations presented in the historical financial information included herein.

We have limited experience operating as a stand-alone wholesale electric power generation company in a deregulated market. Our generation facilities were formerly owned by Reliant Energy, which conveyed these facilities to us in accordance with a business separation plan adopted in response to the Texas electric restructuring law.

The historical financial information covering periods prior to 2002 does not reflect what our financial position, results of operations and cash flows would have been had our generation facilities been operated under the current deregulated ERCOT market. Although our generation facilities had a significant operating history at the time they were conveyed to us, the historical financial information relating to the operation of these facilities during periods prior to 2002 reflects the sale of the power generated by the facilities as part of an integrated utility at regulated rates. We currently sell the power generated by these facilities at market-based prices in capacity auctions, and our revenues currently depend, in large part, upon prevailing market

prices for electricity in the ERCOT market and the related results of the auctions. To date, our capacity auctions have been consummated at market-based prices that have resulted in returns substantially below the historical regulated return on our facilities.

The historical financial information we have included herein also does not reflect what our financial position, results of operations and cash flows would have been had we been a separate entity during the periods presented. Our historical costs and expenses included in our financial statements reflect charges from Reliant Energy for centralized corporate services and operating infrastructure costs as well as allocated costs of capital. These allocations have been determined based on what we and Reliant Energy considered to be reasonable reflections of the utilization of services provided to us or for the benefits received by us. We may experience significant changes in our cost structure, capitalization and operations as a result of our separation from Reliant Energy, including increased costs associated with reduced economies of scale and with being a publicly traded company.

We may not have access to sufficient capital in the amounts and at the times needed to finance our business.

To date, our capital has been provided by internally generated cash flows and borrowings from a "money pool" through which we and certain of our affiliates can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The money pool's net funding requirements are generally met with short-term borrowings of CenterPoint Energy. In the event CenterPoint Energy were to experience liquidity problems or otherwise failed to perform, we may be unable to obtain third party financing. At December 31, 2002, we had borrowings of $86.2 million from the money pool. We can give no assurances that our current and future capital structure, operating performance, financial condition and cash flows will permit us to access the capital markets or to obtain other financing as needed to meet our working capital requirements and projected future capital expenditures on favorable terms. The amount of any debt issuance by us is expected to be affected by the market's perception of our creditworthiness, market conditions and factors affecting our industry. Our projected future capital expenditures are substantial. Our ability to secure third party credit lines or other debt financing may be adversely impacted by the factors described in this section, including the nature of our business, which may lead to volatility in our financial results and cash flows. CenterPoint Energy has agreed to lend funds to us from time to time upon our request until the earlier of the closing date on which Reliant Resources acquires Texas Genco common stock from CenterPoint Energy pursuant to the Reliant Resources option or upon the expiration of the Reliant Resources option. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Future Sources and Uses of Cash — Capital Requirements."

In addition, our ability to raise capital is restricted under our agreements with CenterPoint Energy. These restrictions limit our ability to:

- issue additional equity securities;
- encumber our assets; or
- incur indebtedness, except to satisfy requirements for operating and maintenance expenditures and other capital expenditures contemplated under our agreements with CenterPoint Energy, to meet our working capital needs, or to refinance indebtedness incurred for the foregoing purposes.

In connection with CenterPoint Energy's registration as a public utility holding company under the 1935 Act, the SEC has limited the aggregate amount of our external borrowings to $500 million. The SEC's financing order issued to CenterPoint Energy under the 1935 Act also restricts our ability to pay dividends out of capital accounts. Under these restrictions, we are permitted to pay dividends out of our current or retained earnings, and we may also pay dividends in an amount of up to $100 million in excess of our current or retained earnings. This financing order expires on June 30, 2003. If CenterPiont Energy is unable to obtain an extension of the financing order, we would generally be unable to engage in any financing transactions, including the refinancing of existing obligations after June 30, 2003.

We are an 81% owned subsidiary of CenterPoint Energy. As a result of this relationship, the financial condition of CenterPoint Energy could affect our access to capital, our credit standing and our financial condition.

Our operations are subject to extensive regulation. If we fail to comply with applicable regulations or obtain or maintain any necessary governmental permit or approval, we may be subject to civil, administrative and/or criminal penalties which could adversely impact our results of operations, financial condition and cash flows.

Our operations are subject to complex and stringent energy, environmental and other governmental laws and regulations. The acquisition, ownership and operation of power generation facilities require numerous permits, approvals and certificates from federal, state and local governmental agencies. These facilities are subject to regulation by the Texas Utility Commission regarding non-rate matters. Existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or any of our generation facilities or future changes in laws and regulations may have a detrimental effect on our business.

Operation of the South Texas Project is subject to regulation by the NRC. This regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstrations to the NRC that plant operations meet applicable requirements are also required. The NRC has the ultimate authority to determine whether any nuclear powered generating unit may operate.

Water for certain of our facilities is obtained from public water authorities. New or revised interpretations of existing agreements by those authorities or changes in price or availability of water may have a detrimental effect on our business.

If we fail to comply with regulatory requirements that apply to our operations, regulatory agencies could seek to impose civil, administrative and/or criminal liabilities or could take other actions seeking to curtail our operations. These liabilities or actions could adversely impact our results of operations, financial condition and cash flows.

Our costs of compliance with environmental laws are significant and the cost of compliance with new environmental laws and our exposure to potential liabilities associated with the environmental condition of our facilities could adversely affect our profitability.

Our business is subject to extensive environmental regulation by federal, state and local authorities. We are required to comply with numerous environmental laws and regulations, and to obtain numerous governmental permits, in operating our facilities. We may incur significant additional costs to comply with these requirements. If we fail to comply with these requirements, we could be subject to civil or criminal liability and fines. Existing environmental regulations could be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur, including potential regulatory and enforcement developments related to air emissions. If any of these events occurs, our business, results of operations, financial condition and cash flows could be adversely affected.

We may not be able to obtain or maintain from time to time all required environmental regulatory approvals. If there is a delay in obtaining any required environmental regulatory approvals or if we fail to obtain and comply with them, we may not be able to operate our facilities or we may be required to incur additional costs.

We are generally responsible for all on-site liabilities associated with the environmental condition of our power generation facilities, regardless of when the liabilities arose and whether the liabilities are known or unknown. These liabilities may be substantial.

Changes in technology may make our power generation facilities less competitive, which could adversely impact their value and the results of our operations.

A significant portion of our generation facilities were constructed many years ago and rely on older technologies. Some of our competitors may have newer generation facilities and technologies that allow them to produce and sell power more efficiently, which could adversely affect our results of operations, financial condition and cash flows. In addition, research and development activities are ongoing to improve alternate technologies to produce electricity, including fuel cells, microturbines, windmills and photovoltaic (solar) cells. It is possible that advances in these or other technologies will reduce the current costs of electricity production to a level that is below that of our generation facilities. If this occurs, our generation facilities will be less competitive and the value of our power plants could be significantly impaired. Also, electricity demand could be reduced by increased conservation efforts and advances in technology that could likewise significantly reduce the value of our power generation facilities.

Our insurance coverage may not be sufficient. Insufficient insurance coverage and increased insurance costs could adversely impact our results of operations, financial condition and cash flows.

We have insurance covering certain of our facilities, including property damage insurance, commercial general public liability insurance, boiler and machinery coverage and available replacement capacity in amounts that we consider appropriate. However, our insurance policies are subject to certain limits and deductibles and do not include business interruption coverage. We cannot assure you that insurance coverage will be available in the future on commercially reasonable terms or that the insurance proceeds received for any loss of or any damage to any of our generation facilities will be sufficient to restore the loss or damage without negative impact on our results of operations, financial condition and cash flows. The costs of our insurance coverage have increased significantly during the past year and may continue to increase in the future.

We and the other owners of the South Texas Project maintain nuclear property and nuclear liability insurance coverage as required by law and periodically review available limits and coverage for additional protection. The owners of the South Texas Project currently maintain $2.75 billion in property damage insurance coverage, which is above the legally required minimum, but is less than the total amount of insurance currently available for such losses. Under the federal Price Anderson Act, the maximum liability to the public of owners of nuclear power plants was $9.3 billion as of December 31, 2002. Owners are required under the Price Anderson Act to insure their liability for nuclear incidents and protective evacuations. We and the other owners of the South Texas Project currently maintain the required nuclear liability insurance and participate in the industry retrospective rating plan. In addition, the security procedures at this facility have recently been enhanced to provide additional protection against terrorist attacks. All potential losses or liabilities associated with the South Texas Project may not be insurable, and the amount of insurance may not be sufficient to cover them.

Risks Related to Our Relationships With CenterPoint Energy and Reliant Resources

We will be controlled by CenterPoint Energy as long as it owns a majority of our common stock, and our minority shareholders will be unable to affect the outcome of shareholder voting during that time. If Reliant Resources exercises its option to acquire our stock owned by CenterPoint Energy that is exercisable in January 2004, we will likewise be controlled by Reliant Resources and our minority shareholders will be unable to affect the outcome of a shareholder vote.

As a result of the January 6, 2003 distribution, CenterPoint Energy indirectly owns approximately 81% of our outstanding common stock. As long as CenterPoint Energy owns a majority of our outstanding common stock, it will continue to be able to elect our entire board of directors, and our public shareholders, by themselves, will not be able to affect the outcome of any shareholder vote. Similarly, our public shareholders, by themselves, will not be able to affect the outcome of any shareholder vote if Reliant Resources exercises its option to acquire our common stock owned by CenterPoint Energy that is exercisable in January 2004, as Reliant Resources would own approximately 81% of our common stock in that event. For convenience, we

sometimes refer to CenterPoint Energy or Reliant Resources, as applicable, as our "majority shareholder" when referring to either of them as the owner of 81% or more of our common stock. In addition, CenterPoint Energy has stated that if Reliant Resources does not exercise its option, CenterPoint Energy will consider strategic alternatives for its interest in Texas Genco, including a possible sale, which could result in a third party becoming the majority shareholder of Texas Genco. Reliant Resources may choose not to exercise its option for a number of reasons, including unfavorable market conditions or a lack of access to capital.

Our majority shareholder, subject to any fiduciary duty owed to our minority shareholders under Texas law and restrictions under a master separation agreement between CenterPoint Energy and Reliant Resources, will be able to control all matters affecting us.

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

We may have potential business conflicts of interest with CenterPoint Energy with respect to our past and ongoing relationships, and because of CenterPoint Energy's controlling ownership interest, we may not be able to resolve these conflicts on terms possible in arm's length transactions.

Conflicts of interest may arise between CenterPoint Energy and us in a number of areas relating to our past and ongoing relationships, including proceedings, actions and decisions of legislative bodies and administrative agencies, and our dividend policy. The agreements we have entered into with CenterPoint Energy may be amended in the future upon agreement of the parties. While we are controlled by CenterPoint Energy, CenterPoint Energy may be able to require us to amend these agreements. We may not be able to resolve any potential conflicts with CenterPoint Energy, and even if we do, the resolution may be less favorable than if we were dealing with an unaffiliated party.

Contractual restrictions on the operation of our business may adversely affect our ability to compete with companies that are not subject to similar restrictions.

Effective December 31, 2000, Reliant Resources and Reliant Energy entered into a master separation agreement that now governs the rights and obligations of CenterPoint Energy and Reliant Resources in connection with the business separation plan of Reliant Energy adopted in response to the Texas electric restructuring law. Reliant Resources also has an option to purchase the shares of our stock owned by us that is exercisable in January 2004. We have agreed to comply with certain restrictions governing our operations as contemplated by the master separation agreement and option agreement. These restrictions limit our ability to:

- merge or consolidate with another entity;
- sell assets;
- enter into long-term agreements and commitments for the purchase of fuel or the purchase or sale of power outside the ordinary course of business;
- engage in other businesses;
- construct or acquire new generation plants or capacity;
- engage in certain hedging transactions;
- encumber our assets;
- issue additional equity securities;
- pay special dividends; and
- make certain loans, investments or advances to, or engage in certain transactions with, our affiliates.

If Reliant Resources exercises its option to acquire our stock owned by CenterPoint Energy in 2004, the tax basis of our assets will be adjusted upwards or downwards to reflect the fair market value of our business at the time of the purchase.

We would be required to step up or step down the tax basis in all of our assets following the date of the sale to be equivalent generally to the value of the equity of our business, based upon the purchase price, plus the principal amount of indebtedness at the time of the purchase. The resulting step-up or step-down in the basis of our assets would impact our future tax liabilities. A step-up would reduce our future tax liabilities, while a step-down would increase our liabilities. We cannot currently project the impact of this tax election because it is dependent on Reliant Resources' exercise of its option in 2004, and the purchase price to be paid by Reliant Resources in 2004, which is not known at this time.

Item 2. *Properties.*

Our central support facility includes office space, a maintenance shop, a chemical lab, a warehouse facility and a fleet maintenance garage. This facility includes a total of approximately 521,000 square feet of space, of which approximately 407,000 square feet is occupied by us and approximately 114,000 square feet is leased to Reliant Resources. We also lease approximately 7,100 square feet at CenterPoint Energy's principal office building.

In addition, we lease or own various real property and facilities relating to our generation assets and other vacant real property unrelated to our generation assets. We have described our principal generation and support facilities under "Our Generation Portfolio" in Item 1 of this report, which description is incorporated herein by reference. We believe we have satisfactory title to our facilities in accordance with standards generally accepted in the electric power industry, subject to exceptions that, in our opinion, would not have a material adverse effect on the use or value of the facilities.

Item 3. *Legal Proceedings.*

We are, from time to time, a party to litigation arising in the normal course of our business, most of which involves contract disputes or claims for personal injury and property damage incurred in connection with our operations. We are not currently involved in any litigation that we expect will have a material adverse effect on our financial condition, results of operations and cash flows. For a description of a number of lawsuits involving claims of asbestos exposure at properties owned by us, please read "Environmental Matters — Asbestos" in Item 1 of this report, which description is incorporated herein by reference.

Item 4. *Submission of Matters to a Vote of Security Holders.*

In December 2002, CenterPoint Energy, as holder of all of the then outstanding shares of common stock of Texas Genco, approved by written consent (i) the amendment of Texas Genco's articles of incorporation to effect an 80,000-for-one stock split, and (ii) the subsequent amendment and restatement of Texas Genco's articles of incorporation.

PART II

Item 5. *Market for Common Stock and Related Stockholder Matters.*

As of February 25, 2003, our common stock was held by approximately 55,169 shareholders of record. Our common stock is listed on the New York Stock Exchange and is traded under the symbol "TGN."

On January 6, 2003, CenterPoint Energy distributed approximately 19% of the 80,000,000 outstanding shares of Texas Genco common stock to CenterPoint Energy's shareholders of record as of the close of business on December 20, 2002, the record date for the distribution. Our common stock began trading regular-way on the New York Stock Exchange on January 7, 2003. Accordingly, no high and low sales price information is available for any full quarterly period within the two most recent fiscal years.

We intend to pay regular quarterly cash dividends on our common stock. Our board of directors will determine the amount of future dividends in light of:

- any applicable contractual restrictions governing our ability to pay dividends, including our agreements with CenterPoint Energy to ensure its compliance with the terms of the Reliant Resources option agreement;
- applicable legal requirements;
- our earnings and cash flows;
- our financial condition; and
- other factors our board of directors deems relevant.

On February 7, 2003, our board of directors declared an initial quarterly cash dividend of $0.25 per share of common stock payable on March 20, 2003 to shareholders of record as of the close of business on February 26, 2003.

In February 2003, CenterPoint Energy and Reliant Resources amended the agreement governing the Reliant Resources option. Under the terms of the amended agreement, Texas Genco is required to establish a dividend policy under which it will distribute to its shareholders a dividend based on Texas Genco's earnings and cashflows, subject to any limitations under corporate law or applicable regulatory restrictions, its financial condition and other factors deemed relevant by Texas Genco's board of directors. The dividend policy is required to be set annually for each calendar year, with the initial annual dividend for 2003 expected to be $1.00. The established annual dividend amount may be revised during any calendar year in the event Texas Genco's board of directors reasonably concludes that circumstances would warrant a change or that an adjustment is required to the dividend to satisfy its obligations to Texas Genco. However, the annual dividend amount may only be increased by up to 10% once during any calendar year. The annual dividend amount is required to be paid through regular quarterly cash dividends. Under the amended option agreement, Reliant Resources has agreed that this dividend policy will be maintained so long as it owns less than 100% of Texas Genco's outstanding common stock. The agreement also prohibits Texas Genco from paying any dividends in cash, stock or property, other than pursuant to the dividend policy described above or dividends payable solely in Texas Genco common stock.

In connection with CenterPoint Energy's registration as a public utility holding company under the 1935 Act, the SEC has limited our ability to pay dividends out of capital accounts. Under these restrictions, we are permitted to pay dividends out of our current or retained earnings, and we may also pay dividends in an amount of up to $100 million in excess of our current or retained earnings.

CenterPoint Energy currently owns approximately 81% of Texas Genco's outstanding common stock. In February 2003, CenterPoint Energy reached an agreement with a syndicate of banks on a second amendment to its $3.85 billion bank facility. Under the terms of the amendment, CenterPoint Energy agreed with the banks to grant a security interest in its 81% stock ownership of Texas Genco to secure its borrowings under the bank facility, which would require SEC approval under the 1935 Act. CenterPoint Energy is seeking approval from the SEC to grant the security interest.

Item 6. ***Selected Financial Data.***

The following tables present our selected financial data. The data set forth below should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our historical financial statements and the notes to those statements included in this report. Our selected financial data for each of the four years in the period ended December 31, 2002 are derived from our audited financial statements. Our selected financial data for the year ended December 31, 1998 has been derived from our unaudited financial statements. Our financial statements for periods prior to January 1, 2002 are presented on a carve-out basis and represent the historical financial position, results of operations and net cash flows of the historically regulated generation-related business of Reliant Energy. Therefore, the historical information included in our financial statements is not indicative of our future performance and does not reflect what our financial position and results of operations would have been had we operated as a separate, stand-alone wholesale electric power generation company in a deregulated market during the periods presented. Prior to January 1, 2002, our historical financial information reflects the sale of power generated by our facilities as part of an integrated utility at regulated rates. Since January 1, 2002, we have sold power at market-based prices in capacity auctions. In addition, our historical costs and expenses reflect charges from CenterPoint Energy for centralized corporate services and operating infrastructure costs as well as allocated costs of capital. We may experience significant changes in our cost structure, capitalization and operations as a result of our separation from CenterPoint Energy, including increased costs associated with reduced economies of scale, obtaining third-party financing and being a publicly traded company.

	Year Ended December 31,				
	1998(1)	1999	2000	2001	2002
			(in millions)		
Income Statement Data:					
Revenues	$2,908	$2,816	$3,334	$3,411	$1,541
Expenses:					
Fuel costs	1,065	1,170	1,644	1,304	989
Purchased power	390	395	753	1,223	94
Operation and maintenance	383	384	393	402	391
Depreciation and amortization	582	393	151	154	157
Taxes other than income taxes	88	79	63	63	43
Total	2,508	2,421	3,004	3,146	1,674
Operating Income (Loss)	400	395	330	265	(133)
Other Income	3	14	1	2	3
Interest Expense, net	103	71	59	65	26
Income (Loss) Before Income Taxes and Extraordinary Item	300	338	272	202	(156)
Income Tax Expense (Benefit)	101	113	100	74	(63)
Income (Loss) Before Extraordinary Item	199	225	172	128	(93)
Extraordinary Item, net of tax(2)	—	(518)	—	—	—
Net Income (Loss)	$ 199	$ (293)	$ 172	$ 128	$ (93)
Earnings (Loss) Per Share(3)	$ 2.49	$(3.66)	$ 2.15	$ 1.60	$(1.16)

(1) Interest expense for 1998 has been adjusted from the amounts previously reported based on a revised allocation for interest costs.

(2) Represents a loss related to an accounting impairment of certain generating facilities.

(3) The earnings per share figures are computed by dividing the net income (loss) for each period by 80,000,000, the number of shares of Texas Genco common stock outstanding after the 80,000-for-one stock split declared by Texas Genco's Board of Directors, as effected on December 18, 2002.

	Year Ended December 31, 2000	2001	2002
	(in millions)		
Statement of Cash Flow Data:			
Cash provided by (used in):			
Operating Activities	$ 433	$ 236	$(152)
Investing Activities	(252)	(409)	(245)
Financing Activities	(181)	173	398

	1998	1999	December 31, 2000	2001	2002
			(in millions)		
Balance Sheet Data:					
Property, Plant and Equipment, net	$4,717	$3,583	$3,667	$3,905	$3,981
Total Assets	5,003	3,914	4,032	4,323	4,389
Capitalization(1)	3,102	2,331	2,323	2,624	—
Shareholder's Equity(1)	—	—	—	—	2,824

(1) Upon the restructuring of Reliant Energy pursuant to its business separation plan, effective August 31, 2002, our equity structure was changed to reflect the contribution of CenterPoint Energy's electric generating facilities to us.

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

The following discussion and analysis should be read in combination with our consolidated financial statements and notes contained in Item 8 herein.

OVERVIEW

We are one of the largest wholesale electric power generating companies in the United States. As of December 31, 2002, the aggregate net generating capacity of our portfolio of assets was 14,175 MW. We sell electric generation capacity, energy and ancillary services in the Electric Reliability Council of Texas (ERCOT) market, which is the largest power market in the State of Texas. The ERCOT market consists of the majority of the population centers in the State of Texas and facilitates reliable grid operations for approximately 85% of the demand for power in the state.

Our Separation from CenterPoint Energy

Legislation enacted by the Texas legislature in 1999 (Texas electric restructuring law) requires the restructuring of electric utilities in Texas in order to separate their power generation, transmission and distribution, and retail electric provider businesses into separate units. In March 2001, the Public Utility Commission of Texas (Texas Utility Commission) approved a business separation plan for Reliant Energy involving the separation of Reliant Energy's generation, transmission and distribution, and retail businesses into three separate companies. Effective August 31, 2002, Reliant Energy consummated a restructuring transaction (Reliant Restructuring) in accordance with its business separation plan in which it, among other things:

- conveyed all of its electric generating facilities to us;
- became a subsidiary of CenterPoint Energy; and
- converted into a limited liability company named CenterPoint Energy Houston Electric, LLC (CenterPoint Houston).

Although our portfolio of generating facilities was formerly owned by the unincorporated electric utility division of Reliant Energy, for convenience, we describe our business as if we had owned and operated our generation facilities prior to the date they were conveyed to us. The book value of the net assets conveyed to us by Reliant Energy on August 31, 2002 was approximately $2.8 billion.

On January 6, 2003, CenterPoint Energy distributed approximately 19% of the 80 million outstanding shares of Texas Genco's common stock to CenterPoint Energy's shareholders (distribution). As used herein, CenterPoint Energy also refers to the former Reliant Energy for dates prior to the Reliant Restructuring.

The following discussion and analysis of our results of operations have been derived from our audited historical financial statements and the notes to those financial statements included herein, which we refer to collectively as "our financial statements." Our financial statements were developed using a number of assumptions to separate our operations from those of Reliant Energy, which until January 1, 2002, operated our generation assets together with its transmission and distribution facilities and retail operations as a vertically integrated utility company. Please read Note 1 to our financial statements for a discussion of these assumptions and the methodologies used to prepare our financial statements. The historical financial information for 2000 and 2001 included in our financial statements may not be indicative of our future performance and does not reflect what our financial position and results of operations would have been had we operated as a separate, stand-alone wholesale electric power generation company in a deregulated market during the periods presented.

Prior to January 1, 2002, our revenues were calculated by unbundling the generation component of revenue from CenterPoint Energy's historical bundled rate for the generation and transmission, distribution and sale of energy and adding any additional generation-related revenues of CenterPoint Energy, such as wholesale activities that include ancillary services, trading and capacity sales.

Our energy costs consist primarily of our fuel costs associated with consuming nuclear fuel, gas, oil, lignite and coal to generate energy, as well as our power purchases from the wholesale marketplace. The recent deregulation of the ERCOT market has impacted our energy costs in several ways. As a result of requirements under the Texas electric restructuring law and the terms of our agreements with CenterPoint Energy, we are obligated to sell substantially all of our available capacity and related ancillary services through 2003. In these auctions, we sell on a forward basis firm entitlements to capacity and ancillary services dispatched within specified operational constraints. Although we have reserved a portion of our aggregate net generation capacity from our capacity auctions for planned or forced outages at our facilities, unanticipated plant outages or other problems with our generation facilities could result in our firm capacity and ancillary services commitments exceeding our available generation capacity. As a result, we could be required to obtain replacement power from third parties in the open market to satisfy our firm commitments which could involve the incurrence of significant additional costs. In addition, an unexpected outage at one of our lower cost facilities could require us to run one of our higher cost plants in order to satisfy our obligations. High wholesale power prices for replacement power in the ERCOT market could increase our energy costs and affect earnings and net cash flow.

In 2002, our capacity auctions were consummated at market-based prices that have resulted in returns substantially below the historical regulated return on our facilities that we have experienced in the past. However, we have begun to see improvement in auction prices for our 2003 capacity entitlements. Since the pricing of our generation products is sensitive to gas prices, higher gas prices in the latter part of 2002 have positively influenced the prices in our recent capacity auctions. Because we have a significant amount of low-cost base-load solid fuel and nuclear generating units, higher gas prices generally increase the profitability of our base-load capacity entitlements since prospective purchasers face higher-cost gas-fired generation alternatives. With the higher market prices and our efforts to reduce our operating costs, we expect to show an improvement in profitability for 2003. However, we do not expect this improvement will recover to the levels of our historical regulated returns in the near future due in part to the current surplus of generating capacity in the ERCOT market and changes to the economic conditions affecting our industry that have occurred since our base-load facilities were originally constructed, including the development of high efficiency gas-fired generating units.

With an increasingly competitive wholesale energy market, the composition and level of our operation and maintenance expense is likely to change. To develop our historical financial statements prior to 2002, we have separated the operation and maintenance expense of the generation-related portion of CenterPoint Energy's business from CenterPoint Energy's historical financial statements. These expenses were either

specifically identified by function and reported accordingly or various allocations were used to disaggregate common expenses.

RESULTS OF OPERATIONS

Net Income (Loss)

The following table indicates our net income (loss) for the periods shown (in millions):

	Year Ended December 31,		
	2000	2001	2002
Net Income (Loss)	$172	$128	$(93)

Our net income for the year ended December 31, 2002 decreased $221 million from the comparable 2001 period. This decrease primarily resulted from the implementation of deregulation of the wholesale power segment of the ERCOT market under the Texas electric restructuring law in 2002 resulting in substantially lower revenues partially offset by reduced operations and maintenance, and other tax expense.

Our net income for the year ended December 31, 2001 decreased $44 million from the comparable 2000 period. This decrease was a result of the reduction in rate base on which the regulatory return was calculated.

Revenues

Revenues decreased $1.9 billion or 55% for the year ended December 31, 2002 from the comparable 2001 period. The decrease was primarily due to the change from a regulatory method used to allocate the integrated utility revenue of CenterPoint Energy for the 2001 period to the revenue generated in 2002 in the deregulated ERCOT market. Our 2001 revenue was derived based on actual recoverable operating expenses plus an allowed regulatory rate of return based on the rate base while our 2002 revenue was derived from open market sales of capacity and energy products at auction and spot market prices.

Revenues increased $77 million or 2% for the year ended December 31, 2001 from the comparable 2000 period. The increase was primarily due to an increase in recoverable fuel related revenues of $131 million related to increased fuel costs discussed below, partially offset by the reduction in the rate base on which the regulatory return was calculated due to additional depreciation expense related to these assets of $36 million and a decrease in other recoverable operating expenses of $18 million.

Fuel and Purchased Power Expenses

Fuel and purchased power expenses decreased $1.4 billion or 57% for the year ended December 31, 2002 from the comparable 2001 period. The decrease is due primarily to lower natural gas prices ($4.23 and $3.32 per MMBtu or $842 million and $468 million in 2001 and 2002, respectively) and a reduction in purchased power ($44.42 and $24.50 per MWh or $1.2 billion and $94 million in 2001 and 2002, respectively) related to overall demand reductions for output from our facilities.

Fuel and purchased power expenses increased $130 million or 5% for the year ended December 31, 2001 from the comparable 2000 period. The increase was due primarily to increased purchased power volumes related to load balancing requirements associated with the ERCOT market adopting a single control area and a slightly higher average cost for purchased power ($44.26 and $44.42 per MWh or $727 million and $1.2 billion in 2000 and 2001, respectively). This was offset by a decline in the volume of natural gas used at a slightly higher average price ($3.98 and $4.23 per MMBtu or $1.2 billion and $842 million in 2000 and 2001, respectively).

Operation and Maintenance Expense

Operation and maintenance expense decreased $11 million or 3% for the year ended December 31, 2002 from the comparable 2001 period. The decrease was primarily due to an absence of major maintenance

outages at our W. A. Parish and Limestone solid fuel plants, several gas plants and the South Texas Project in 2002 ($36 million in 2001). The decrease was partially offset by costs related to an early retirement program implemented in 2002 ($12 million), business separation expenses ($7 million) and computer systems necessary for operation in the deregulated market ($6 million).

Operation and maintenance expense increased $9 million or 2% for the year ended December 31, 2001 from the comparable 2000 period. The increase was primarily due to major maintenance outages at our Limestone, Cedar Bayou, San Jacinto and T. H. Wharton generation facilities resulting in costs of $16 million during 2001 without corresponding outages in 2000. The outage cycles are a part of our normal maintenance practice to ensure the reliability of our generating portfolio. There are years in which the cycles result in more outages occurring simultaneously than in other years. The increase was partially offset by lower labor costs of $7 million related to lower staffing levels.

Depreciation and Amortization Expense

Depreciation and amortization expense increased $3 million or 2% for the year ended December 31, 2002 from the comparable 2001 period. Depreciation and amortization expense increased $3 million or 2% for the year ended December 31, 2001 from the comparable 2000 period. The increases were due to normal increases in property, plant and equipment.

Interest Expense

Interest expense decreased $39 million or 60% for the year ended December 31, 2002 from the comparable 2001 period. The decrease was due to the change from the allocation method based on capital structure used to calculate interest expense in 2001 to the allocation of interest in 2002 based on the remaining electric utility debt not specifically identified with CenterPoint Energy's transmission and distribution utility upon deregulation. In connection with the Reliant Restructuring and the conveyance of all of CenterPoint Energy's electric generating facilities to us in August 2002, we did not assume any of CenterPoint Energy's long-term debt.

Interest expense increased $6 million or 11% for the year ended December 31, 2001 from the comparable 2000 period. The increase was due to the underlying change in the capital structure on which interest was allocated.

Income Tax Expense (Benefit)

The effective tax rates for 2002 and 2001 were 40.3% and 36.5%, respectively. The increase in the effective rate for 2002 compared to 2001 was primarily the result of a reduced benefit from the amortization of investment tax credits, offset by a decrease in state income taxes. The Company's state tax liability changed from an income-based tax for 2001, to a capital-based tax for 2002, primarily as a result of the 2002 pre-tax loss, which resulted in the reporting of the state tax as a component of the pre-tax loss for 2002 compared to reporting the state tax expense as a component of income tax expense for 2001.

The effective tax rates for 2001 and 2000 were 36.5% and 36.8%, respectively.

RELATED PARTY TRANSACTIONS

Our Relationships With CenterPoint Energy

Separation Agreement. In connection with the distribution, we entered into a separation agreement with CenterPoint Energy. This agreement contains provisions governing our relationship with CenterPoint Energy following the distribution and specifies the related ancillary agreements between us and CenterPoint Energy. In addition, the separation agreement provides for cross-indemnities intended to place sole financial responsibility on us and our subsidiaries for all liabilities associated with the current and historical business and operations we conduct, regardless of the time those liabilities arose, and to place sole financial responsibility for liabilities associated with CenterPoint Energy's other businesses with CenterPoint Energy

and its other subsidiaries. The separation agreement also contains indemnification provisions under which we and CenterPoint Energy each indemnify the other with respect to breaches by the indemnifying party of the separation agreement or any ancillary agreements.

Transition Services Agreement. We have entered into a transition services agreement with CenterPoint Energy under which CenterPoint Energy will provide us through the earlier of such time as all services under the agreement are terminated or CenterPoint Energy ceases to own a majority of our common stock, various corporate support services that include accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs and human resources, as well as information technology services and other previously shared services such as corporate security, facilities management, accounts receivable, accounts payable and payroll, office support services and purchasing and logistics. These services will consist generally of the same types of services as have been provided on an intercompany basis prior to this distribution. The charges we will pay for the services will be on a basis generally intended to allow CenterPoint Energy to recover the fully allocated direct and indirect costs of providing the services, plus all out-of-pocket costs and expenses, but without any profit to CenterPoint Energy, except to the extent routinely included in traditional utility cost of capital. Pursuant to a separate lease agreement, CenterPoint Energy has agreed to lease office space in its principal office building in Houston, Texas to us for an interim period expected to end no later than December 31, 2004.

Tax Allocation Agreement. We are members of the CenterPoint Energy consolidated group for tax purposes, and we will continue to file a consolidated federal income tax return with CenterPoint Energy while CenterPoint Energy retains its 81% interest in us. Accordingly, we have entered into a tax allocation agreement with CenterPoint Energy to govern the allocation of U.S. income tax liabilities and to set forth agreements with respect to certain other tax matters. CenterPoint Energy will be responsible for preparing and filing any U.S. income tax returns required to be filed for any company or group of companies of the CenterPoint Energy consolidated group, including all tax returns for Texas Genco for so long as we are members of the CenterPoint Energy consolidated group. CenterPoint Energy will also be responsible for paying the taxes related to the returns it is responsible for filing. We will be responsible for paying CenterPoint Energy our allocable share of such taxes. CenterPoint Energy will determine all tax elections for tax periods during which we are a member of the CenterPoint Energy consolidated group. Generally, if there are tax adjustments related to us which relate to a tax return filed for a period when we were a member of the CenterPoint Energy consolidated group, we will be responsible for any increased taxes and we will receive the benefit of any tax refunds.

Employee Benefit Plans. Our eligible employees currently participate in CenterPoint Energy's employee benefit plans and programs in accordance with the terms and conditions of such plans and programs, as may be amended or terminated by CenterPoint Energy at any time.

Reliant Resources Option

As part of Reliant Energy's business separation plan, Reliant Resources was granted an option that may be exercised between January 10, 2004 and January 24, 2004 to purchase all of the approximately 81% of the outstanding shares of Texas Genco common stock currently owned by CenterPoint Energy. The terms of the option agreement were amended in February 2003. The per share exercise price under the Reliant Resources option will equal the average daily closing price of Texas Genco common stock on The New York Stock Exchange over the 30 consecutive trading days out of the last 120 trading days ending January 9, 2004 which result in the highest average closing price. In addition, a control premium, up to a maximum of 10%, will be added to the price to the extent a control premium is included in the valuation determination made by the Texas Utility Commission relating to the market value of Texas Genco. If the option closing has not occurred within sixteen months of the option exercise, rights under the option agreement will terminate. Reliant Resources will be entitled to rescind its exercise of the option by giving notice to CenterPoint Energy on or before the 45th day following the option exercise date if Reliant Resources has been unable by that date to secure financing for its purchase of the shares of Texas Genco common stock on terms reasonably acceptable to Reliant Resources. Upon the giving of such notice of rescission, the option period will be deemed to have expired without exercise of the option.

The exercise price formula is based upon the generation asset valuation methodology in the Texas electric restructuring law that we will use to calculate the market value of Texas Genco. The exercise price is also subject to adjustment based on the difference between the per share dividends we pay to CenterPoint Energy during the period from January 6, 2003 through the option closing date and our actual per share earnings during that period. To the extent our per share dividends are less than our actual per share earnings during that period, the per share option price will be increased. To the extent our per share dividends exceed our actual per share earnings, the per share option price will be reduced.

Reliant Resources has agreed that if it exercises its option, Reliant Resources will purchase from CenterPoint Energy all notes and other payables owed by us to CenterPoint Energy as of the option closing date, at their principal amount plus accrued interest. Similarly, if there are notes or payables owed to us by CenterPoint Energy as of the option closing date, Reliant Resources will assume those obligations in exchange for a payment from CenterPoint Energy of an amount equal to the principal plus accrued interest.

In the event Reliant Resources exercises its option, we would be required to step-up or step-down the tax basis in all of its assets following the date of the sale to be equivalent generally to the value of the equity of Texas Genco, based upon the purchase price, plus the principal amount of Texas Genco's indebtedness at the time of the purchase.

In connection with the Reliant Resources option, we are obligated to operate and maintain our assets and otherwise conduct our business in the ordinary course in a manner consistent with past practice and to make expenditures for operations, maintenance, repair and capital expenditures necessary to keep our assets in good condition and in compliance with applicable laws, in a manner consistent with good electric generation industry practice. We are also required to maintain customary levels of insurance, comply with laws and contractual obligations and pay taxes when due. We may not permanently retire generation units, but may "mothball" units if economically warranted.

Under an agreement with Reliant Resources, CenterPoint Energy has agreed to maintain ownership of its approximate 81% interest in Texas Genco following the distribution until exercise or expiration of the Reliant Resources option. Reliant Resources has granted a waiver that would permit CenterPoint Energy to grant a security interest in its 81% interest in Texas Genco to CenterPoint Energy's creditors. In addition, we have agreed that we will not issue additional equity securities. CenterPoint Energy has agreed to lend funds to us for operating needs upon request from time to time following the distribution. We may also obtain third-party financing if we so desire. Our agreements with CenterPoint Energy contain covenants restricting our ability to:

- merge or consolidate with another entity;
- sell assets;
- enter into long-term agreements and commitments for the purchase of fuel or the purchase or sale of power outside the ordinary course of business;
- engage in other businesses;
- construct or acquire new generation plants or capacity;
- engage in hedging transactions;
- encumber our assets;
- issue additional equity securities;
- pay special dividends; and
- make certain loans, investments or advances to, or engage in certain transactions with, our affiliates.

Exercise of the Reliant Resources option will be subject to various regulatory approvals, including Hart-Scott-Rodino antitrust clearance and NRC license transfer approval. In certain circumstances involving a change in control of us, the time at which the Reliant Resources option may be exercised and the period over

which the exercise price is determined are accelerated, with corresponding changes to the time and manner of payment of the exercise price.

For a description of the limitations on our ability to pay dividends, please read "Market for Common Stock and Related Stockholder Matters" in Item 5 of this report.

Technical Services Agreement with Reliant Resources

Under a technical services agreement, Reliant Resources is obligated to provide engineering and technical support services and environmental, safety and industrial health services to support the operation and maintenance of our facilities. Reliant Resources is also obligated to provide systems, technical, programming and consulting support services and hardware maintenance (but excluding plant-specific hardware) necessary to provide dispatch planning, dispatch, and settlement and communication with the ERCOT ISO, as well as general information technology services for us. The fees Reliant Resources charges for these services are designed to allow it to recover its fully allocated direct and indirect costs and to obtain reimbursement of all out-of-pocket expenses. Expenses associated with capital investment in systems and software that benefit both the operation of Reliant Resources' facilities and our facilities will be allocated on an installed MW basis.

The technical services agreement will terminate on the first to occur of:

- the closing date on which Reliant Resources acquires the Texas Genco shares from CenterPoint Energy, if the Reliant Resources option is exercised;
- CenterPoint Energy's sale of Texas Genco, or all or substantially all of our assets, if the Reliant Resources option is not exercised; or
- May 31, 2005, provided that if the Reliant Resources option is not exercised, we may extend the term of this agreement until December 31, 2005.

Capacity Auctions

Through 2003, Reliant Resources has the contractual right, but not the obligation, to purchase 50% (but not less than 50%) of each type of capacity entitlement we auction in our contractually mandated auctions at the prices established in the auctions. To exercise this right, Reliant Resources is required to notify us whether it elects to purchase 50% of the capacity auctioned no later than three business days prior to the date of the auction. We exclude the amount of capacity specified in Reliant Resources' notice from the auction. We auction any portion of the capacity that Reliant Resources does not reserve through its notice with the balance of the capacity we auction in the contractually mandated auctions.

Upon determination of the auction prices for the capacity entitlements we auction, Reliant Resources is obligated to purchase the capacity it elected to reserve from the auction process at the prices set during the auction for that entitlement. If we auction capacity and ancillary services separately, Reliant Resources is entitled to participate in 50% of the offered capacity of each. In addition to its reservation of capacity, and whether or not it has reserved capacity in the auction, Reliant Resources is entitled to participate in each contractually mandated auction. If Reliant Resources exercises the Reliant Resources option, we will not conduct any capacity auctions, other than as required by Texas Utility Commission rules, between the option exercise date and the option closing date without obtaining Reliant Resources' consent, which it may not unreasonably withhold. If Reliant Resources does not exercise its option, we will cease to be required to conduct contractually mandated auctions following the option exercise period.

We sold 91% of our available capacity for 2002 and 74% of our available capacity for 2003. Reliant Resources purchased entitlements to 63% of the available 2002 capacity and through January 2003 has purchased 58% of the available 2003 capacity. These purchases were made either through the exercise by Reliant Resources of its contractual rights to purchase 50% of the entitlements auctioned in the contractually mandated auctions or through the submission of bids in those auctions. In either case, these purchases were made at market-based prices.

South Texas Project Decommissioning Trust

We are the beneficiary of the decommissioning trust that has been established to provide funding for decontamination and decommissioning of the South Texas Project in which we own a 30.8% interest. CenterPoint Houston collects, through rates or other authorized charges to its electric utility customers, amounts designated for funding the decommissioning trust, and deposits these amounts into the decommissioning trust. Upon decommissioning of the facility, in the event funds from the trust are inadequate, CenterPoint Houston or its successor will be required to collect through rates or other authorized charges to customers as contemplated by the Texas Utilities Code all additional amounts required to fund our obligations relating to the decommissioning of the facility. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trust, the excess will be refunded to the ratepayers of CenterPoint Houston or its successor.

Common Director

Our Chairman, David M. McClanahan, is also a director and the chief executive officer of CenterPoint Energy. As a result, he may need to recuse himself and not participate in board meetings where actions are taken in connection with transactions or other relationships involving both companies.

CERTAIN FACTORS AFFECTING FUTURE EARNINGS

Our past earnings and results of operations are not necessarily indicative of our future earnings and results of operations. Any of the following factors could adversely affect our business prospects, financial condition, operating results and cash flows:

- state and federal legislative and regulatory actions or developments, including deregulation; re-regulation and restructuring of the ERCOT market; and changes in, or application of, environmental and other laws or regulations to which we are subject;
- the effects of competition, including the extent and timing of the entry of additional competitors in the ERCOT market;
- the results of our capacity auctions;
- the timing and extent of changes in commodity prices, particularly natural gas;
- weather variations and other natural phenomena;
- unanticipated changes in operating expenses and capital expenditures;
- financial distress of our customers, including Reliant Resources;
- our access to capital and credit;
- political, legal and economic conditions and developments in the United States; and
- other factors discussed in this report under "Risk Factors."

LIQUIDITY AND CAPITAL RESOURCES

Historical Cash Flows

The net cash provided by/used in our operating, investing and financing activities for 2000, 2001 and 2002 is as follows (in millions):

	Year Ended December 31,		
	2000	2001	2002
Cash provided by (used in):			
Operating activities	$ 433	$ 236	$(152)
Investing activities	(252)	(409)	(245)
Financing activities	(181)	173	398

Cash Provided by Operating Activities

Net cash provided by operating activities in 2002 decreased $388 million compared to 2001. The decrease primarily resulted from lower revenues in the deregulated ERCOT market, increased accounts receivable from the sale of power in the 2002 deregulated electricity market and lower taxes payable.

Net cash provided by operating activities in 2001 decreased $197 million compared to 2000. This decrease primarily resulted from a reduction in base revenue related to a decline in the rate base on which the regulatory return was calculated and a decrease in fuel accounts payable related to the decrease in the price of natural gas in 2001 as compared to 2000.

Cash Used in Investing Activities

Net cash used in investing activities decreased $164 million during 2002 compared to 2001.

Net cash used in investing activities increased $157 million during 2001 compared to 2000.

The decrease in 2002 compared to 2001 is from completing a major portion of the NOx work on our solid fuel units at W.A. Parish and the re-scheduling of the NOx installation on our gas units. The increase in 2001 compared to 2000 was due primarily to increased capital expenditures for installation of equipment to reduce emissions of oxides of nitrogen (NOx) from our generating units.

Cash Provided by Financing Activities

Cash provided by financing activities increased $225 million during 2002 compared to 2001.

Cash provided by financing activities increased $354 million in 2001 compared to 2000.

The changes in cash flows provided by (used in) financing activities in each of the periods discussed above were a result of transfers to and from our parent company to support our various requirements for working capital and capital expenditures.

Future Sources and Uses of Cash

We expect to meet our future capital requirements with cash flows from operations, as well as a combination of intercompany loans from our affiliates and external funding as necessary. From time to time we may use the proceeds of our third party borrowings to repay intercompany indebtedness, make dividend payments or for other corporate purposes. We have obtained consent from Reliant Resources to grant security interests in our assets to lenders under third party facilities. We believe that our cash flows from operations, intercompany loans from our affiliates and our borrowing capability will be sufficient to meet the operational needs of our business for the next twelve months. For a discussion of factors that may impact our access to capital, please read "Risk Factors — Other Risks."

In February 2003, CenterPoint Energy reached an agreement with a syndicate of banks on a second amendment to its $3.85 billion bank facility. Under the terms of the amended bank facility, CenterPoint Energy agreed with the banks not to permit us to incur indebtedness for borrowed money in an aggregate principal amount at any one time outstanding in excess of $250 million. In addition, CenterPoint Energy agreed that proceeds from the sale of any material portion of our assets, subject to certain requirements, or our incurrence of indebtedness for borrowed money in excess of specified levels would be used to prepay outstanding indebtedness under the bank facility. Although we are not contractually bound by these limitations, CenterPoint Energy would likely cause its representatives on our board of directors to direct our business so as not to breach the terms of the agreement.

Prior to the restructuring of Reliant Energy pursuant to its business separation plan, CenterPoint Energy and Reliant Energy obtained an order from the SEC that granted CenterPoint Energy certain authority with respect to financing, dividends and other matters. The financing authority granted by that order will expire on June 30, 2003, and CenterPoint Energy must obtain a further order from the SEC under the 1935 Act in order for it and its subsidiaries, including us, to engage in financing activities subsequent to that date. For more information regarding the restrictions on our activities under the financing order, please read "Our Business — Regulation — Public Utility Holding Company Act of 1935" in Item 1 of this report.

Capital Requirements. The following table sets forth our capital requirements for 2002, and estimates of our capital requirements for 2003 through 2007 (in millions).

	2002	2003	2004	2005	2006	2007
Environmental capital requirements	$220	$ 98	$ 33	$ —	$ —	$ —
Other capital requirements	60	52	63	68	51	64
Total capital requirements	$280	$150	$ 96	$ 68	$ 51	$ 64

Environmental expenditures for installation of equipment to reduce NOx emissions are expected to decline between 2003 and 2004 in accordance with our NOx emission reduction plan approved by the Texas Utility Commission. Environmental compliance cost estimates for 2006 and 2007 have not been finalized.

Contractual Obligations. The following table sets forth estimates of our contractual obligations as of December 31, 2002 to make future payments for 2003 through 2007 and thereafter (in millions):

Contractual Obligations	Total	2003	2004	2005	2006	2007	2008 and thereafter
Fuel commitments	$1,410	$292	$165	$169	$174	$167	$443
Operating lease commitments	$ 110	$ 11	$ 11	$ 11	$ 10	$ 10	$ 57

Revenues derived from our capacity auctions come from two sources: capacity payments and energy payments. Energy payments consist of a variety of charges related to the fuel and ancillary services scheduled through our auctioned capacity entitlements. We bill for these energy payments on a monthly basis in arrears. We expect future collected energy payments will cover all of our future fuel commitments.

Cash Flows From Operations — Reliant Resources as a Significant Customer. To date, we have sold a substantial portion of our auctioned capacity entitlements to subsidiaries of Reliant Resources. For more information regarding the impact that Reliant Resources' financial condition may have on our cash flows, please read Risk Factors — Factors Related to Operating Risks."

Dividend Policy. We intend to pay regular quarterly cash dividends on our common stock. Our board of directors will determine the amount of future dividends in light of:

- any applicable contractual restrictions governing our ability to pay dividends, including our agreements with CenterPoint Energy to ensure its compliance with the terms of the Reliant Resources option agreement;

- applicable legal requirements;
- our earnings and cash flows;
- our financial condition; and
- other factors our board of directors deems relevant.

On February 7, 2003, our board of directors declared an initial quarterly cash dividend of $0.25 per share of common stock payable on March 20, 2003 to shareholders of record as of the close of business on February 26, 2003. For a description of certain contractual provisions governing Texas Genco's ability to pay dividends, please read "Market for Common Stock and Related Stockholder Matters" in Item 5 of this report.

We expect our liquidity and capital requirements will be affected by our:

- capital requirements related to environmental compliance and other maintenance projects;
- dividend policy;
- debt service requirements; and
- working capital requirements.

Money Pool. At December 31, 2002, we had $86.2 million borrowed from affiliates. We participate in a "money pool" through which we and certain of our affiliates can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The money pool's net funding requirements are generally met by borrowings of CenterPoint Energy. The terms of the money pool are in accordance with requirements applicable to registered public utility holding companies under the 1935 Act. The money pool may not provide sufficient funds to meet our cash needs.

Pension Plan. As discussed in Note 6(a) to the consolidated financial statements, we participate in CenterPoint Energy's qualified non-contributory pension plan covering substantially all employees. Pension expense for 2003 is estimated to be $17 million based on an expected return on plan assets of 9.0% and a discount rate of 6.75% as of December 31, 2002. Future changes in plan asset returns, assumed discount rates and various other factors related to the pension will impact our future pension expense and liabilities. We cannot predict with certainty what these factors will be in the future.

CRITICAL ACCOUNTING POLICIES

A critical accounting policy is one that is both important to the presentation of our financial condition and results of operations and requires management to make difficult, subjective or complex accounting estimates. An accounting estimate is an approximation made by management of a financial statement element, item or account in the financial statements. Accounting estimates in our historical consolidated financial statements measure the effects of past business transactions or events, or the present status of an asset or liability. The accounting estimates described below require us to make assumptions about matters that are highly uncertain at the time the estimate is made. Additionally, different estimates that we could have used or changes in an accounting estimate that are reasonable likely to occur could have a material impact on the presentation of our financial condition or results of operations. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. We believe the following critical accounting policies involve the application of accounting estimates for which a change in the estimate is inseparable from the effect of a change in accounting principle.

Allocation Methodologies Used to Derive Our Financial Statements On a Carve-Out Basis

In 2000 and 2001, we employed various allocation methodologies to separate the results of operations and financial condition of the generation-related portion of CenterPoint Energy's business from CenterPoint Energy's historical financial statements in order to prepare our financial statements. For 2000 and 2001,

revenues were allocated based on actual costs plus an allowed regulatory rate of return based on regulated invested capital granted to CenterPoint Energy's electric utility by the Texas Utility Commission. The allowed regulatory rate of return was 9.844% for 2000 and 2001. Expenses, such as fuel, purchased power, operations and maintenance, and depreciation and amortization, and assets, such as property, plant and equipment, and inventory, were specifically identified by function and allocated accordingly for our operations. We used various allocations to disaggregate other common expenses, assets and liabilities between our operations and CenterPoint Energy's regulated transmission and distribution operations. We calculated interest expense based upon an allocation methodology that charged us with financing and equity costs from CenterPoint Energy in proportion to our share of total net assets prior to the effects of deregulation discussed below. These methodologies reflect the impact of deregulation on our assets and liabilities as of June 30, 1999; however, all existing regulatory assets which are expected to be recovered as "stranded costs" by our affiliated transmission and distribution utility, CenterPoint Houston, after deregulation have been excluded from these financial statements.

Beginning January 1, 2002, CenterPoint Energy's generation business was segregated from its electric utility as a separate reporting business segment and began selling electricity in the ERCOT market at prices determined by the market. Accordingly, for 2002, net income reflects the results of market prices for power. Included in operations for 2002 are allocations from CenterPoint Energy for corporate services that included accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs and human resources, as well as information technology services and other previously shared services such as corporate security, facilities management, accounts receivable, accounts payable and payroll, office support services and purchasing and logistics.

Management believes the estimates inherent in these allocation methodologies to be reasonable. Had we actually existed as a separate company, our results could have significantly differed from those presented herein. In addition, the historical financial information included in our financial statements is not indicative of our future performance and does not reflect what our financial position and results of operations would have been had we operated as a separate, stand-alone wholesale electric power generation company in a deregulated market during the periods presented.

Revenue Recognition

Starting January 1, 2002, we have two primary components of revenue: (1) capacity revenues, which entitle the owner to power, and (2) energy revenues, which are intended to cover the costs of fuel for the actual electricity produced. Capacity payments are billed and collected one month prior to actual energy deliveries and are recorded as deferred revenue until the month of actual energy delivery. At that point, the deferred revenue is reversed, and both capacity and energy payment revenues are recognized. As of December 31, 2002 $49 million of deferred capacity revenue was recorded in our Consolidated Balance Sheet.

Impairment of Long-Lived Assets

Long-lived assets, which primarily include property, plant and equipment (PP&E), comprise $4.0 billion or 91% of our total assets as of December 31, 2002. We make judgments and estimates in conjunction with the carrying value of these assets, including amounts to be capitalized, depreciation and amortization methods and useful lives. We evaluate our PP&E for impairment whenever indicators of impairment exist. During 2002, no such indicators of impairment existed. Accounting standards require that if the sum of the undiscounted expected future cash flows from a company's asset is less than the carrying value of the asset, an asset impairment must be recognized. The amount of impairment recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset.

As a result of the distribution of approximately 19% of Texas Genco's common stock to CenterPoint Energy's shareholders on January 6, 2003, we re-evaluated these assets for impairment as of December 31, 2002 in accordance with SFAS No. 144. As of December 31, 2002, no impairment had been indicated.

an exit or disposal activity when it is incurred. A liability is incurred when a transaction or event occurs that leaves an entity little or no discretion to avoid the future transfer or use of assets to settle the liability. Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. In addition, SFAS No. 146 also requires that a liability for a cost associated with an exit or disposal activity be recognized at its fair value when it is incurred. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002 with early application encouraged. We will apply the provisions of SFAS No. 146 to all exit or disposal activities initiated after December 31, 2002.

Item 7A. *Qualitative and Quantitative Disclosures About Market Risk.*

Interest Rate Risk

As discussed in Note 8(c) to our financial statements, we contributed $14.8 million per year in 2000 and 2001 to a trust established to fund our share of the decommissioning costs for the South Texas Project. In 2002, we began contributing $2.9 million per year to this trust. The securities held by the trust for decommissioning costs had an estimated fair value of $163 million as of December 31, 2002, of which approximately 49% were debt securities that subject us to risk of loss of fair value with movements in market interest rates. If interest rates were to increase by 10% from their levels at December 31, 2002, the decrease in fair value of the debt securities would be approximately $1 million. In addition, the risk of an economic loss is mitigated because CenterPoint Energy has agreed to indemnify us for any shortfall of the trust to cover decommissioning costs.

Equity Market Value Risk

As discussed above under "— Interest Rate Risk," we contribute to a trust established to fund our share of the decommissioning costs for the South Texas Project, which held debt and equity securities as of December 31, 2002. The equity securities expose us to losses in fair value. If the market prices of the individual equity securities were to decrease by 10% from their levels at December 31, 2002, the resulting loss in fair value of these securities would be approximately $8 million. Currently, the risk of an economic loss is mitigated because CenterPoint Energy has agreed to indemnify us for any shortfall of the trust to cover decommissioning costs.

Commodity Price Risk

Our gross margins are dependent upon the market price for power in the ERCOT market. Our gross margins are primarily derived from the sale of capacity entitlements associated with our large, solid fuel base-load generating units, including our Limestone and W.A. Parish facilities and our interest in the South Texas Project. The gross margins generated from payments associated with the capacity of these units are directly impacted by natural gas prices. Since the fuel costs for our base-load units are largely fixed under long-term contracts, they are generally not subject to significant daily and monthly fluctuations. However, the market price for power in the ERCOT market is directly affected by the price of natural gas. Because natural gas is the marginal fuel of facilities serving the ERCOT market during most hours, its price has a significant influence on the price of electric power. As a result, the price customers are willing to pay for entitlements to our solid fuel base-load capacity generally rises and falls with natural gas prices.

Item 8. ***Financial Statements and Supplementary Data of the Company.***

TEXAS GENCO HOLDINGS, INC.

STATEMENTS OF CONSOLIDATED OPERATIONS
(Thousands of Dollars)

	Year Ended December 31, 2000	2001	2002
Revenues:			
Revenues	$3,333,550	$3,410,945	$ —
Energy revenues	—	—	1,093,714
Capacity and other revenues	—	—	447,261
Total	3,333,550	3,410,945	1,540,975
Expenses:			
Fuel costs	1,644,301	1,303,981	989,560
Purchased power	752,455	1,222,552	93,841
Operation and maintenance	392,489	401,677	391,465
Depreciation and amortization	151,098	154,248	156,740
Taxes other than income taxes	63,301	63,378	42,930
Total	3,003,644	3,145,836	1,674,536
Operating Income (Loss)	329,906	265,109	(133,561)
Other Income	1,379	2,100	3,423
Interest Expense, net	58,550	65,017	25,637
Income (Loss) Before Income Taxes	272,735	202,192	(155,775)
Income Tax Expense (Benefit)	100,346	73,804	(62,832)
Net Income (Loss)	$ 172,389	$ 128,388	$ (92,943)
Basic and Diluted Earnings Per Share	$ 2.15	$ 1.60	$ (1.16)

See Notes to the Company's Consolidated Financial Statements

TEXAS GENCO HOLDINGS, INC.

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars)

	December 31, 2001	December 31, 2002
ASSETS		
Current Assets:		
Cash and cash equivalents	$ —	$ 578
Customer accounts receivable	—	68,604
Accounts receivable, other	38,173	4,544
Inventory	180,249	156,167
Prepayments and other current assets	3,008	4,024
Total current assets	221,430	233,917
Property, Plant and Equipment, net	3,904,853	3,980,770
Other Assets:		
Nuclear decommissioning trust	168,982	162,576
Other	27,481	11,584
Total other assets	196,463	174,160
Total Assets	$4,322,746	$4,388,847
LIABILITIES, CAPITALIZATION AND SHAREHOLDER'S EQUITY		
Current Liabilities:		
Accounts payable, affiliated companies, net	$ 48,426	$ 22,652
Accounts payable, fuel	100,725	76,399
Accounts payable, other	95,210	43,877
Notes payable, affiliated companies, net	—	86,186
Taxes and interest accrued	122,687	38,591
Other	14,661	15,918
Total current liabilities	381,709	283,623
Other Liabilities:		
Accumulated deferred income taxes, net	900,746	813,246
Unamortized investment tax credit	182,713	170,569
Nuclear decommissioning reserve	137,542	139,664
Deferred capacity auction revenue	—	48,721
Benefit obligations	33,174	15,751
Accrued reclamation costs	28,431	39,765
Notes payable, affiliated companies, net	—	18,995
Other	34,415	34,470
Total other liabilities	1,317,021	1,281,181
Commitments and Contingencies (Note 8)		
Capitalization	2,624,016	—
Shareholder's Equity:		
Capital stock	—	1
Additional paid-in capital	—	2,878,502
Retained deficit	—	(54,460)
Total Shareholder's Equity	—	2,824,043
Total Capitalization and Shareholder's Equity	2,624,016	2,824,043
Total Liabilities, Capitalization and Shareholder's Equity	$4,322,746	$4,388,847

See Notes to the Company's Consolidated Financial Statements

TEXAS GENCO HOLDINGS, INC.

STATEMENTS OF CONSOLIDATED CASH FLOWS
(Thousands of Dollars)

	Year Ended December 31, 2000	2001	2002
Cash Flows from Operating Activities:			
Net income (loss)	$ 172,389	$ 128,388	$ (92,943)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and amortization	151,098	154,248	156,740
Fuel-related amortization	17,746	16,740	12,729
Deferred income taxes	19,639	(29,194)	(27,161)
Investment tax credit	(13,082)	(13,106)	(12,144)
Changes in other assets and liabilities:			
Accounts receivable	3,245	(19,554)	(34,975)
Inventory	(8,696)	(16,483)	24,082
Accounts payable	142,669	(95,490)	(75,659)
Accounts payable, affiliate	19,227	19,743	(25,774)
Taxes and interest accrued	(37,767)	60,608	(84,096)
Accrued reclamation costs	1,162	8,505	11,334
Benefit obligations	5,984	2,453	(17,423)
Deferred revenue from capacity auctions	—	—	48,721
Other current assets	656	(491)	(1,016)
Other current liabilities	4,020	(665)	1,257
Other long-term assets	(15,904)	(5,822)	15,757
Other long-term liabilities	(29,405)	26,209	(51,756)
Net cash provided by (used in) operating activities	432,981	236,089	(152,327)
Cash Flows from Investing Activities:			
Capital expenditures	(252,301)	(409,002)	(245,246)
Net cash used in investing activities	(252,301)	(409,002)	(245,246)
Cash Flows from Financing Activities:			
Net change in capitalization activity	(180,680)	172,913	292,970
Increase in short-term notes payables, affiliate	—	—	86,186
Increase in long-term notes payable, affiliate	—	—	18,995
Net cash provided by (used in) financing activities	(180,680)	172,913	398,151
Net Increase in Cash and Cash Equivalents	—	—	578
Cash and Cash Equivalents at Beginning of Period	—	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —	$ 578
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest	$ 58,597	$ 64,267	$ 4,270
Income taxes	87,413	60,963	—

See Notes to the Company's Consolidated Financial Statements

TEXAS GENCO HOLDINGS, INC.

STATEMENTS OF CONSOLIDATED CAPITALIZATION AND SHAREHOLDER'S EQUITY
(Thousands of Dollars)

	Capital Stock	Additional Paid-In Capital	Retained Deficit	Total Shareholder's Equity	Capitalization	Total Capitalization and Shareholder's Equity
Balance as of December 31, 1999	$—	$ —	$ —	$ —	$ 2,331,006	$2,331,006
Net income (1)	—	—	—	—	172,389	172,389
Net transfers to parent	—	—	—	—	(180,680)	(180,680)
Balance as of December 31, 2000	—	—	—	—	2,322,715	2,322,715
Net income (1)	—	—	—	—	128,388	128,388
Net transfers from parent	—	—	—	—	172,913	172,913
Balance as of December 31, 2001	—	—	—	—	2,624,016	2,624,016
Net loss (2)	—	—	(54,460)	(54,460)	(38,483)	(92,943)
Net transfers from parent	1	2,878,502	—	2,878,503	(2,585,533)	292,970
Balance as of December 31, 2002	$ 1	$2,878,502	$(54,460)	$2,824,043	$ —	$2,824,043

(1) Net income included in Capitalization for 2000 and 2001, reflects the net income derived from the allocation of revenue, operating expenses, other income, interest expense and income tax expense from the rate regulated electric utility of Reliant Energy, Incorporated, (Reliant Energy) the predecessor of CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which was comprised of transmission and distribution, generation and retail components. For further discussion related to the basis of presentation, See Note 1.

(2) Beginning January 1, 2002, Reliant Energy's electric generation business was segregated in an unincorporated division from its other electric utility operations as a separate reporting business segment. In June 1999, the Texas legislature enacted a law that substantially amended the regulatory structure governing electric utilities in Texas in order to encourage retail electric competition (the Texas electric restructuring law). Under the Texas electric restructuring law, the Company and other power generators in Texas ceased to be subject to traditional cost-based regulation on January 1, 2002. Since that date, the Company has been selling generation capacity, energy and ancillary services to wholesale purchasers at prices determined by the market. Accordingly, for 2002, net loss reflects revenue received from market-based power sales. Retained deficit at December 31, 2002 reflects the Company's net loss since August 31, 2002, the date of the restructuring as discussed in Note 1. The Company's net loss prior to the restructuring is reflected as a component of capitalization.

See Notes to the Company's Consolidated Financial Statements

TEXAS GENCO HOLDINGS, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

Background. In June 1999, the Texas legislature enacted an electric restructuring law which substantially amended the regulatory structure governing electric utilities in Texas in order to encourage retail electric competition. In December 2001, the shareholders of Reliant Energy, Incorporated (Reliant Energy) approved a restructuring proposal that was submitted in response to the Texas electric restructuring law and pursuant to which Reliant Energy would, among other things, (1) convey its Texas electric generation assets to an affiliated company, (2) become an indirect, wholly owned subsidiary of a new public utility holding company, CenterPoint Energy, Inc. (CenterPoint Energy), (3) be converted into a Texas limited liability company named CenterPoint Energy Houston Electric, LLC (CenterPoint Houston) and (4) distribute the capital stock of its operating subsidiaries to CenterPoint Energy. Texas Genco Holdings, Inc. (Texas Genco or the Company) represents the portfolio of generating facilities owned during the periods presented by these financial statements by the unincorporated electric utility division of Reliant Energy.

On August 24, 2001, Reliant Energy incorporated Texas Genco, a Texas corporation, as a wholly owned subsidiary. In February 2002, the Company issued 1,000 shares of its $1.00 par value common stock to Reliant Energy in exchange for $1,000. In February 2002, Reliant Energy made a capital contribution of $3,000 to the Company. During the period ended June 30, 2002, Reliant Energy made a capital contribution of $14,000 to the Company for payment of general and administrative expenses associated with maintaining its corporate structure. The Company did not conduct any activities other than those mentioned above through August 31, 2002.

Effective August 31, 2002, Reliant Energy completed the restructuring described above. As a result, on that date Reliant Energy conveyed all of its electric generating facilities to the Company, which was accounted for as a business combination of entities under common control. The Company subsequently became an indirect wholly owned subsidiary of CenterPoint Energy. CenterPoint Energy is subject to regulation by the Securities and Exchange Commission as a "registered holding company" under the Public Utility Holding Company Act of 1935. As used herein, CenterPoint Energy also refers to the former Reliant Energy for dates prior to the restructuring.

As of January 1, 2002, CenterPoint Energy's electric utility unbundled its businesses in order to separate its power generation, transmission and distribution, and retail electric businesses into separate units. Under the Texas electric restructuring law, as of January 1, 2002, the Company ceased to be subject to traditional cost-based regulation. Since that date, the Company has been selling generation capacity, energy and ancillary services to wholesale purchasers at prices determined by the market. To facilitate a competitive market, each power generation company affiliated with a transmission and distribution utility is required to sell at auction firm entitlements to 15% of the output of its installed generating capacity on a forward basis for varying terms of up to two years (state mandated auctions). The Company's first state mandated auction was held in September 2001 for power delivered beginning January 1, 2002. This obligation continues until January 1, 2007 unless before that date the Public Utility Commission of Texas (Texas Utility Commission) determines that at least 40% of the quantity of electric power consumed in 2000 by residential and small commercial customers in CenterPoint Houston's service area is being served by retail electric providers not affiliated with CenterPoint Energy. Reliant Resources, Inc. (Reliant Resources) is deemed to be an affiliate of CenterPoint Energy for purposes of this test. Reliant Resources has an option (Reliant Resources Option) to purchase the shares of the Company's common stock owned by CenterPoint Energy that is exercisable in January 2004. In addition to the state mandated auctions, the Company is contractually obligated to auction entitlements to all of its capacity and related ancillary services available, subject to certain permitted reserves, until the date on which the Reliant Resources Option is either exercised or expires (contractually mandated auctions). Reliant Resources is entitled to purchase 50% (but no less than 50% if it exercises this purchase entitlement) of each type of capacity entitlement auctioned by the Company in the contractually mandated auctions at the prices established in the auctions.

Basis of Presentation. The consolidated financial statements include the operations of Texas Genco Holdings, Inc. and its subsidiaries, which manage and operate the Company's electric generation operations. The consolidated financial statements of the Company are presented on a carve-out basis, and present the historical financial position, results of operations and net cash flows of the historically regulated generation-related business of CenterPoint Energy, and are not indicative of the financial position, results of operations or net cash flows that would have existed had the Company been an independent company operating in the Texas deregulated electricity market (ERCOT market) for the two years ended December 31, 2001. Beginning January 1, 2002, CenterPoint Energy's generation business was segregated from CenterPoint Energy's electric utility as a separate reporting business segment and began selling electricity in the ERCOT market at prices determined by the market. Accordingly, for 2002, net loss reflects the results of market prices for power. Included in operations for 2002 are allocations from CenterPoint Energy for corporate services that included accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs and human resources, as well as information technology services and other previously shared services such as corporate security, facilities management, accounts receivable, accounts payable and payroll, office support services and purchasing and logistics.

Certain information in these consolidated financial statements as of December 31, 2002 and for each of the years in the two-year period ended December 31, 2002 relating to the results of operations and financial condition was derived from the historical financial statements of CenterPoint Energy which have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). Various allocation methodologies were employed during these periods to separate the results of operations and financial condition of the generation-related portion of CenterPoint Energy's business from CenterPoint Energy's historical financial statements. For 2000 and 2001, revenues were allocated based on the allowed regulatory rate of return on regulated invested capital granted to CenterPoint Energy's electric utility by the Texas Utility Commission. The allowed regulatory rate of return was 9.844% for 2000 and 2001. Expenses during 2000 and 2001, such as fuel, purchased power, operations and maintenance and depreciation and amortization, and assets, such as property, plant and equipment and inventory, were specifically identified by function and allocated accordingly for the Company's operations. Various allocations were used to disaggregate other common expenses, assets and liabilities between the Company and CenterPoint Energy's regulated transmission and distribution operations as of December 31, 2001 and for the two-year period then ended. Interest expense was calculated based upon an allocation methodology that charged the Company with financing and equity costs from CenterPoint Energy in proportion to its share of total net assets. Interest expense in 2002 through August 31, 2002 was allocated based upon the remaining electric utility debt not specifically identified with Reliant Energy's transmission and distribution utility upon deregulation. Effective with the restructuring of Reliant Energy, no long-term debt was assumed by the Company and interest is incurred on borrowings from CenterPoint Energy. These methodologies reflect the impact of deregulation on the Company's assets and liabilities as of June 30, 1999; however, all existing regulatory assets which are expected to be recovered by the transmission and distribution utility after deregulation have been excluded from these consolidated financial statements.

Management believes these allocation methodologies to be reasonable. Had the Company actually existed as a separate company, its results could have significantly differed from those presented herein. In addition, future results of operations, financial position and net cash flows are expected to materially differ from the historical results presented.

Texas Genco's Board of Directors declared an 80,000-for-one stock split that was effected on December 18, 2002. On January 6, 2003, CenterPoint Energy distributed approximately 19% of the 80 million outstanding shares of Texas Genco's common stock to CenterPoint Energy's shareholders. Earnings per share has been presented as if the 80,000,000 shares were outstanding for all historical periods in accordance with Statement of Financial Accounting Standards (SFAS) No. 128, "Earnings Per Share."

(2) Summary of Significant Accounting Policies

(a) Use of Estimates

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Also, such estimates relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts. In addition to these estimates, see Note 1 (Background and Basis of Presentation) for a discussion of the estimates used and methodologies employed to derive the Company's historical financial statements.

(b) Inventory

Inventory consists principally of materials and supplies, coal and lignite, natural gas and fuel oil. Inventories used in the production of electricity are valued at the lower of average cost or market except for coal and lignite, which are valued under the last-in, first-out method. Below is a detail of inventory:

	December 31, 2001	December 31, 2002
	(in thousands)	
Materials and supplies	$ 93,442	$ 92,869
Coal and lignite	57,826	42,791
Natural gas	19,620	16,733
Fuel oil	9,361	3,774
Total inventory	$180,249	$156,167

(c) Property, Plant and Equipment

Property, plant and equipment are recorded at historical cost. Repair and maintenance costs are charged to the appropriate expense accounts as incurred. Property, plant and equipment includes the following:

	Estimated Useful Lives (Years)	December 31, 2001	December 31, 2002
		(in thousands)	
Gas-fired generation facilities	30–60	$ 2,175,689	$ 2,274,317
Coal and lignite-fired generation facilities	50	3,678,723	3,820,208
Nuclear generation facilities	40	2,884,394	2,905,242
Nuclear fuel		320,312	344,003
Other	5–50	303,256	266,570
Total		9,362,374	9,610,340
Accumulated depreciation and amortization		(5,457,521)	(5,629,570)
Property, plant and equipment, net		$ 3,904,853	$ 3,980,770

Prior to the restructuring described in Note 1 (Background and Basis of Presentation), substantially all of the Company's physical assets used in the conduct of the business and operations of electric generation were subject to liens securing CenterPoint Energy's First Mortgage Bonds. In connection with the restructuring, these assets were released from the liens.

(d) Depreciation and Amortization

Depreciation is computed using the straight-line method based on economic lives or a regulatory mandated method prior to June 30, 1999. Depreciation and amortization expense for 2000, 2001 and 2002 was $151 million, $154 million and $157 million, respectively.

(e) Capitalized Interest

Capitalized interest is reflected as a reduction to interest expense in the Consolidated Statements of Operations. During the years ended December 31, 2000, 2001 and 2002, the Company capitalized interest of $3.9 million, $4.4 million and $6.6 million, respectively.

(f) Long-lived Assets and Intangibles

The Company periodically evaluates long-lived assets when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. An impairment analysis of generating facilities requires estimates of possible future market prices, load growth, competition and many other factors over the lives of the facilities. A resulting impairment loss is highly dependent on these underlying assumptions.

As a result of the distribution of approximately 19% of Texas Genco's common stock to CenterPoint Energy's shareholders on January 6, 2003, the Company re-evaluated these assets for impairment as of December 31, 2002 in accordance with SFAS No. 144. As of December 31, 2002, no impairment had been indicated.

(g) Revenue Recognition

Prior to January 1, 2002, revenues were derived based on actual costs plus an allowed regulatory rate of return based on regulated invested capital. For the periods subsequent to January 1, 2002, the Company has been accounted for as a separate business segment of CenterPoint Energy selling electricity to wholesale purchasers in the ERCOT market. Accordingly, revenues represent actual results of CenterPoint Energy's generation business segment in 2002 operating in a deregulated market. As of January 1, 2002, the Company has two primary components of revenue: (1) capacity payments, which entitles the owner to power, and (2) energy payments, which are intended to cover the costs of fuel for the actual electricity produced. Capacity payments are billed and collected one month prior to actual energy deliveries and are recorded as deferred revenue until the month of actual energy delivery. At that point, the deferred revenue is reversed, and both capacity and energy payment revenues are recognized. Prior to 2002, all purchased power was part of the total load used to serve retail customers of the integrated utility. Beginning in 2002, fuel costs and purchased power are costs incurred to support sales of energy in the state mandated auctions and contractually mandated auctions required by the Texas Utility Commission, and the corresponding revenues are recorded as Energy revenues.

(h) Reclamation Costs

The Company records liabilities related to future reclamation costs when the activities are probable and the costs can be reasonably estimated. As of December 31, 2001 and 2002, the Company has accrued costs related to future reclamation obligations related to its lignite mine at its Limestone generating facility of $28 million and $40 million, respectively.

(i) Income Taxes

The Company is included in the consolidated income tax returns of CenterPoint Energy. The Company calculates its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy. The Company uses the liability method of accounting for deferred income taxes and measures deferred income taxes for all significant income tax temporary differences. Current federal and state income taxes payable are payable to or receivable from CenterPoint Energy.

(j) Statement of Consolidated Cash Flows

For purposes of reporting cash flows, the Company considers cash equivalents to be short-term, highly liquid investments readily convertible to cash.

(k) New Accounting Pronouncements

In July 2001, the FASB issued SFAS No. 142, which provides that goodwill and certain intangibles with indefinite lives will not be amortized into results of operations, but instead will be reviewed periodically for impairment and written down and charged to results of operations only in the periods in which the recorded value of goodwill and certain intangibles with indefinite lives is more than its fair value. Adoption of SFAS No. 142 on January 1, 2002 did not have any impact on the Company's consolidated financial statements.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 requires the fair value of an asset retirement obligation to be recognized as a liability is incurred and capitalized as part of the cost of the related tangible long-lived assets. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. SFAS No. 143 requires entities to record a cumulative effect of change in accounting principle in the income statement in the period of adoption. The Company adopted SFAS No. 143 on January 1, 2003.

The Company has completed an assessment of the applicability and implications of SFAS No. 143. As a result of the assessment, the Company has identified retirement obligations for nuclear decommissioning at the South Texas Nuclear Project (South Texas Project) and for lignite mine operations at the Jewett mine supplying the Limestone electric generation facility. Nuclear decommissioning and the lignite mine have recorded liabilities under the Company's previous method of accounting. Liabilities recorded for estimated decommissioning obligations were $138 million and $140 million at December 31, 2001 and 2002, respectively. Liabilities recorded for estimated lignite mine reclamation costs were $28 million and $40 million at December 31, 2001 and 2002, respectively. The Company has also identified other asset retirement obligations that cannot be calculated because the assets associated with the retirement obligations have an indeterminate life.

The Company used an expected cash flow approach to measure its assets retirement obligations under SFAS No. 143. The following amounts represent the Company's asset retirement obligations on a pro-forma basis as if it had adopted SFAS No. 143 as of the respective dates:

	December 31,	
	2001	2002
	(in millions)	
Nuclear decommissioning	$178	$187
Jewett lignite mine	2	4
Total	$180	$191

The net difference between the amounts determined under SFAS No. 143 and the Company's previous method of accounting for estimated nuclear decommissioning costs of $16 million will be recorded as a liability. The net difference between the amounts determined under SFAS No. 143 and the Company's previous method of accounting for estimated mine reclamation costs of $37 million will be recorded as a cumulative effect of accounting change.

The Company has previously recognized removal costs as a component of depreciation expense. Upon adoption of SFAS No. 143, the Company will reverse $115 million of previously recognized removal costs as a cumulative effect of accounting change.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). SFAS No. 144 provides new guidance on the recognition of impairment losses on long-lived assets to be held and used or to be disposed of and also broadens the definition of what constitutes a discontinued operation and how the results of a discontinued operation are to be measured and presented. Adoption of SFAS No. 144 on January 1, 2002 did not have a material impact on the Company's consolidated financial statements. See Note 2(f) for a discussion of the impairment test performed at December 31, 2002.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS No. 145). SFAS No. 145 eliminates the current requirement that gains and losses on debt extinguishment must be classified as extraordinary items in the income statement. Instead, such gains and losses will be classified as extraordinary items only if they are deemed to be unusual and infrequent. SFAS No. 145 also requires that capital leases that are modified so that the resulting lease agreement is classified as an operating lease be accounted for as a sale-leaseback transaction. The changes related to debt extinguishment will be effective for fiscal years beginning after May 15, 2002, and the changes related to lease accounting will be effective for transactions occurring after May 15, 2002. The Company has applied this guidance prospectively as it relates to lease accounting and will apply the accounting provisions related to debt extinguishment in 2003.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS No. 146). SFAS No. 146 nullifies Emerging Issues Task Force (EITF) No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)" (EITF No. 94-3). The principal difference between SFAS No. 146 and EITF No. 94-3 relates to the requirements for recognition of a liability for cost associated with an exit or disposal activity. SFAS No. 146 requires that a liability be recognized for a cost associated with an exit or disposal activity when it is incurred. A liability is incurred when a transaction or event occurs that leaves an entity little or no discretion to avoid the future transfer or use of assets to settle the liability. Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. In addition, SFAS No. 146 also requires that a liability for a cost associated with an exit or disposal activity be recognized at its fair value when it is incurred. SFAS No. 146 is effective for exit or disposal activities that are

initiated after December 31, 2002 with early application encouraged. The Company will apply the provisions of SFAS No. 146 to all exit or disposal activities initiated after December 31, 2002.

In June 2002, the EITF reached a consensus on EITF No. 02-03 that all mark-to-market gains and losses on energy trading contracts should be shown net in the income statement whether or not settled physically. An entity should disclose the gross transaction volumes for those energy-trading contracts that are physically settled. The EITF did not reach a consensus on whether recognition of dealer profit, or unrealized gains and losses at inception of an energy-trading contract, is appropriate in the absence of quoted market prices or current market transactions for contracts with similar terms. The FASB staff indicated that until such time as a consensus is reached, the FASB staff will continue to hold the view that previous EITF consensus do not allow for recognition of dealer profit, unless evidenced by quoted market prices or other current market transactions for energy trading contracts with similar terms and counterparties. The consensus on presenting gains and losses on energy trading contracts net is effective for financial statements issued for periods ending after July 15, 2002. Upon application of the consensus, comparative financial statements for prior periods should be reclassified to conform to the consensus. Adoption of EITF No. 02-03 did not have any impact on the Company's financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation No. (FIN) 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 requires that a liability be recorded in the guarantor's balance sheet upon issuance of certain guarantees. In addition, FIN 45 requires disclosures about the guarantees that an entity has issued. The provision for initial recognition and measurement of the liability will be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure provisions of FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002. The adoption of FIN 45 is not expected to materially affect the Company's consolidated financial statements. The Company has adopted the additional disclosure provisions of FIN 45 in its consolidated financial statements as of December 31, 2002.

In January 2003, the FASB issued FIN No. 46 "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51" (FIN 46). FIN 46 requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. FIN 46 is effective for all new variable interest entities created or acquired after January 31, 2003. For variable interest entities created or acquired prior to February 1, 2003, the provisions of FIN 46 must be applied for the first interim or annual period beginning after June 15, 2003. The Company is currently evaluating the effect that the adoption of FIN 46 will have on its results of operations and financial condition.

(3) Related Party Transactions

As of December 31, 2002, the Company had $86.2 million in short-term borrowings and $19.0 million in long-term borrowings from CenterPoint Energy and its subsidiaries. Such borrowings are used for working capital purposes. Interest expense associated with the borrowings for 2002 was $7.0 million. The effective interest rate on the borrowings was 6.20%. In addition, through August 31, 2002 (the Restructuring), $25.2 million of interest expense was allocated to the Company related to the remaining electric utility debt not specifically identified with CenterPoint Energy's transmission and distribution utility upon deregulation.

From time to time, the Company has advanced money to, or borrowed money from, CenterPoint Energy or its subsidiaries. As of December 31, 2002, the Company had net accounts payable to affiliates of $23 million.

During 2002, the sales and services by the Company to CenterPoint Energy and its affiliates totaled $53 million. Purchases of natural gas by the Company from CenterPoint Energy and its affiliates were $41 million in 2002.

CenterPoint Energy provides some corporate services to the Company. The costs of services have been directly charged to the Company using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment, and proportionate corporate formulas based on assets, operating expenses and employees. These charges are not necessarily indicative of what would have been incurred had the Company not been an affiliate. Amounts charged to the Company for these services were $47 million for 2002 and are included primarily in operation and maintenance expenses.

The 1935 Act generally prohibits borrowings by CenterPoint Energy from its subsidiaries, including the Company.

Separation Agreement. In connection with the distribution, the Company entered into a separation agreement with CenterPoint Energy. This agreement contains provisions governing the Company's relationship with CenterPoint Energy following the distribution and specifies the related ancillary agreements between the Company and CenterPoint Energy. In addition, the separation agreement provides for cross-indemnities intended to place sole financial responsibility on the Company and its subsidiaries for all liabilities associated with the current and historical business and operations the Company conducts, regardless of the time those liabilities arose, and to place sole financial responsibility for liabilities associated with CenterPoint Energy's other businesses with CenterPoint Energy and its other subsidiaries. The separation agreement also contains indemnification provisions under which the Company and CenterPoint Energy each indemnify the other with respect to breaches by the indemnifying party of the separation agreement or any ancillary agreements.

Transition Services Agreement. The Company has entered into a transition services agreement with CenterPoint Energy under which CenterPoint Energy will provide the Company through the earlier of such time as all services under the agreement are terminated or CenterPoint Energy ceases to own a majority of the Company's common stock, various corporate support services that include accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs and human resources, as well as information technology services and other previously shared services such as corporate security, facilities management, accounts receivable, accounts payable and payroll, office support services and purchasing and logistics. These services will consist generally of the same types of services as have been provided on an intercompany basis prior to this distribution. The charges the Company will pay for the services will be on a basis generally intended to allow CenterPoint Energy to recover the fully allocated direct and indirect costs of providing the services, plus all out-of-pocket costs and expenses, but without any profit to CenterPoint Energy, except to the extent routinely included in traditional utility cost of capital. Pursuant to a separate lease agreement, CenterPoint Energy has agreed to lease office space in its principal office building in Houston, Texas to the Company for an interim period expected to end no later than December 31, 2004.

Tax Allocation Agreement. The Company is a member of the CenterPoint Energy consolidated group for tax purposes, and the Company will continue to file a consolidated federal income tax return with CenterPoint Energy while CenterPoint Energy retains its 81% interest in the Company. Accordingly, the Company has entered into a tax allocation agreement with CenterPoint Energy to govern the allocation of U.S. income tax liabilities and to set forth agreements with respect to certain other tax matters. CenterPoint Energy will be responsible for preparing and filing any U.S. income tax returns required to be filed for any company or group of companies of the CenterPoint Energy consolidated group, including all tax returns for the Company for so long as it is a member of the CenterPoint Energy consolidated group. CenterPoint Energy will also be responsible for paying the taxes related to the returns it is responsible for filing. The Company will be responsible for paying CenterPoint Energy its allocable share of such taxes. CenterPoint Energy will determine all tax elections for tax periods during which the Company is a member of the CenterPoint Energy consolidated group. Generally, if there are tax adjustments related to the Company which relate to a tax return

filed for a period when the Company was a member of the CenterPoint Energy consolidated group, the Company will be responsible for any increased taxes and the Company will receive the benefit of any tax refunds.

(4) Capitalization

CenterPoint Energy has provided the necessary capital to finance the Company's generation related business. The Company had net capitalization of $2.6 billion at December 31, 2001. These amounts represent the amount of capital investments made by Reliant Energy in its generation-related business and the Company's allocated capitalization prior to the formation of the Company as a separate entity. Interest expense for the two years ended December 31, 2001 was calculated based upon an allocation methodology that charged the Company with financing and equity costs from Reliant Energy in proportion to its share of total net assets. Interest expense in 2002 through August 31, 2002 was allocated based upon the remaining electric utility debt not specifically identified with Reliant Energy's transmission and distribution utility upon deregulation. Effective with the restructuring of Reliant Energy on August 31, 2002, no long-term debt was assumed by the Company, and from that point interest has been incurred only on short-term borrowings from CenterPoint Energy.

(5) Jointly Owned Electric Utility Plant

The Company owns a 30.8% interest in the South Texas Project, which consists of two 1,250 MW nuclear generating units, and bears a corresponding 30.8% share of capital and operating costs associated with the project. The South Texas Project is owned as a tenancy in common among the Company and three other co-owners, with each owner retaining its undivided ownership interest in the two nuclear-fueled generating units and the electrical output from those units. The Company is severally liable, but not jointly liable, for the expenses and liabilities of the South Texas Project. CenterPoint Energy and the other three co-owners organized STP Nuclear Operating company (STPNOC) to operate and maintain the South Texas Project. STPNOC is managed by a board of directors comprised of one director appointed by each of the four owners, along with the chief executive officer of STPNOC. The Company's share of direct expenses of the South Texas Project is included in the corresponding operating expense categories in the accompanying financial statements. As of December 31, 2001, the total utility plant in service and construction work in progress for the total South Texas Project was $5.8 billion and $120 million, respectively. As of December 31, 2002, the total utility plant in service and construction work in progress for the total South Texas Project was $5.8 billion and $158 million, respectively. As of December 31, 2001 and 2002, Texas Genco's investment in the South Texas Project was $316 million and $323 million, respectively, (net of $2.2 billion accumulated depreciation which includes an impairment loss recorded in 1999 of $745 million). As of December 31, 2001 and 2002, Texas Genco's investment in nuclear fuel was $35 million (net of $286 million amortization) and $42 million (net of $302 million amortization), respectively.

(6) Employee Benefit Plans

(a) Pension

Substantially all of the Company's employees participate in CenterPoint Energy's qualified non-contributory pension plan. The benefit accrual is in the form of a cash balance of a specified percentage of annual pay plus accrued interest. CenterPoint Energy's funding policy is to review amounts annually in accordance with applicable regulations in order to achieve adequate funding of projected benefit obligations. Pension expense is allocated to the Company based on covered employees. Assets of the plan are not segregated or restricted by CenterPoint Energy's participating subsidiaries and accrued obligations for the Company employees would be the obligation of the retirement plan if the Company were to withdraw. Pension benefit was $5 million and $1 million for the years ended December 31, 2000 and 2001, respectively. The

Company recognized pension expense of $15 million for the year ended December 31, 2002, which includes $9 million of non-recurring expenses related to an early retirement program.

In addition to the plan, the Company participates in CenterPoint Energy's non-qualified pension plan, which allows participants to retain the benefits to which they would have been entitled under the retirement plan except for federally mandated limits on these benefits or on the level of salary on which these benefits may be calculated. The expense associated with the non-qualified pension plan was less than $1 million in 2000, 2001 and 2002.

(b) Savings Plan

The Company participates in CenterPoint Energy's qualified savings plan, which includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended. Under the plan, participating employees may contribute a portion of their compensation, on a pre-tax or after-tax basis, generally up to a maximum of 16% of compensation. CenterPoint Energy matches 75% of the first 6% of each employee's compensation contributed. CenterPoint Energy may contribute an additional discretionary match of up to 50% of the first 6% of each employee's compensation contributed. These matching contributions are fully vested at all times. A substantial portion of the matching contribution is initially invested in CenterPoint Energy common stock. CenterPoint Energy allocates to the Company the savings plan benefit expense related to the Company's employees.

Savings plan benefit expense was $10 million, $6 million and $9 million for the years ended December 31, 2000, 2001 and 2002, respectively.

(c) Postretirement Benefits

The Company's employees participate in CenterPoint Energy's plans which provide certain healthcare and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees become eligible for these benefits if they have met certain age and service requirements at retirement, as defined in the plans. Under plan amendments effective in early 1999, health care benefits for future retirees were changed to limit employer contributions for medical coverage. Such benefit costs are accrued over the active service period of employees.

The Company is required to fund a portion of its obligations in accordance with rate orders. All other obligations are funded on a pay-as-you-go basis.

The net postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2000	2001	2002
	(in millions)		
Service cost — benefits earned during the period	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	6	6	3
Expected return on plan assets	(3)	(4)	(1)
Net amortization	2	4	1
Benefit enhancement	—	—	3
Net postretirement benefit cost	$ 6	$ 7	$ 7

Following are the Company's reconciliations of beginning and ending balances of its postretirement benefit plans benefit obligation, plan assets and funded status for 2001 and 2002.

	Year Ended December 31, 2001	Year Ended December 31, 2002
	(in millions)	
Change in Benefit Obligation		
Benefit obligation, beginning of year	$ 82	$ 89
Service cost	1	1
Interest cost	6	3
Benefits paid	(1)	—
Participant contributions	1	—
Benefit enhancement	—	3
Transfer to affiliate	—	(52)
Actuarial (gain) loss	—	(3)
Benefit obligation, end of year	$ 89	$ 41
Change in Plan Assets		
Plan assets, beginning of year	$ 34	$ 37
Benefits paid	(1)	—
Employer contributions	7	1
Participant contributions	1	—
Transfer to affiliate	—	(22)
Actual investment return	(4)	(1)
Plan assets, end of year	$ 37	$ 15
Reconciliation of Funded Status		
Funded status	$(52)	$(26)
Unrecognized transition obligation	31	8
Unrecognized prior service cost	14	13
Unrecognized actuarial loss	(10)	(5)
Net amount recognized at end of year	$(17)	$(10)
Actuarial Assumptions		
Discount rate	7.25%	6.75%
Expected long-term rate of return on assets	9.5%	9.0%

For the year ended December 31, 2001, the assumed health care cost trend rates were 7.5% for participants under age 65 and 8.5% for participants age 65 and over. For the year ended December 31, 2002, the assumed health cost trend rate was increased to 12% for all participants. The health care cost trend rates decline by .75% annually to 5.5% by 2011.

If the health care cost trend rate assumptions were increased or decreased by 1%, the accumulated postretirement benefit obligation as of December 31, 2002 and the annual effect on the total of the service and interest costs would be unchanged.

The Company's postretirement obligation is presented as a liability in the Consolidated Balance Sheet under the caption Benefit Obligations.

(d) Postemployment Benefits

The Company provides postemployment benefits through CenterPoint Energy plans for former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily health care and life insurance benefits for participants in the long-term disability plan). Postemployment benefits costs were less than $1 million for 2001 and 2002. The Company recognized postemployment benefit income of $2 million for the year ended December 31, 2000.

(e) Other Non-Qualified Plans

The Company participates in CenterPoint Energy's deferred compensation plans which permit eligible participants to elect each year to defer a percentage of up to 100% of that year's salary and that year's annual bonus. Employees may elect to receive an early distribution of their deferral plus interest after at least four years or any year, up to and including their age 65 retirement year. In general, employees who attain the age of 60 during employment and participate in CenterPoint Energy's deferred compensation plans may elect to have their deferred compensation amounts repaid in (a) 15 equal annual installments commencing at the later of age 65 or termination of employment or (b) a lump-sum distribution following termination of employment at age 65. Interest generally accrues on deferrals at a rate equal to the average Moody's Long-Term Corporate Bond Index plus 2%, determined annually until termination when the rate is fixed at the rate in effect for the plan year immediately prior to which a participant attains age 65. The Company recorded interest expense related to its deferred compensation obligation of $2 million, $0.8 million and $0.5 million for the years ended December 31, 2000, 2001 and 2002, respectively. The discounted deferred compensation obligation recorded by the Company was $12 million and $4 million as of December 31, 2001 and 2002, respectively.

(f) Other Employee Matters

As of December 31, 2002, the Company employed approximately 1,639 people. Of these employees, approximately 1,102 are covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers Local 66 that extends through September 2003.

(7) Income Taxes

The Company's current and deferred components of income tax expense were as follows:

	Year Ended December 31,		
	2000	2001	2002
		(in millions)	
Current			
Federal	$ 59,346	$ 90,665	$(23,526)
State	34,444	25,415	—
Total current	93,790	116,080	(23,526)
Deferred			
Federal	6,628	(42,199)	(39,306)
State	(72)	(77)	—
Income tax expense (benefit)	$100,346	$ 73,804	$(62,832)

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	Year Ended December 31,		
	2000	2001	2002
		(in millions)	
Income (loss) before income taxes	$272,735	$202,192	$(155,775)
Federal statutory rate	35%	35%	35%
Income tax expense (benefit) at statutory rate	95,457	70,767	(54,521)
Increase (decrease) in tax resulting from:			
State income taxes, net of federal income tax benefit	22,342	16,470	—
Amortization of investment tax credit	(13,082)	(13,106)	(7,894)
Excess deferred taxes	(3,581)	(4,353)	—
Other, net	(790)	4,026	(417)
Total	4,889	3,037	(8,311)
Income tax expense (benefit)	$100,346	$ 73,804	$ (62,832)
Effective Rate	36.8%	36.5%	40.3%

Following were the Company's tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases:

	December 31,	
	2001	2002
	(in millions)	
Deferred tax assets:		
Non-current:		
Employee benefits	$ 1,668	$ 4,588
Environmental reserves	9,950	13,918
Other	2,174	3,865
Total non-current deferred tax assets	13,792	22,371
Deferred tax liabilities:		
Non-current:		
Depreciation	908,387	829,125
Other	6,151	6,492
Total non-current deferred tax liabilities	914,538	835,617
Accumulated deferred income taxes, net	$900,746	$813,246

The Company is included in the consolidated income tax returns of CenterPoint Energy. CenterPoint Energy's consolidated federal income tax returns have been audited and settled through the 1996 tax year. The 1997, 1998 and 1999 consolidated federal income tax returns are currently under audit. No audit adjustments that would impact the Company have been proposed for the current audit cycle.

(8) Commitments and Contingencies

(a) Fuel and Purchased Power Commitments

Fuel commitments include several long-term coal, lignite and natural gas contracts. Minimum payment obligations related to coal and transportation agreements and lignite mining and lease agreements that extend through 2012 are approximately $292 million in 2003, $165 million in 2004, $169 million in 2005, $174 million in 2006 and $167 million in 2007. Purchase commitments related to purchased power are not material to the Company's operations. As of December 31, 2002, the pricing provisions in some of these contracts were above market.

(b) Lease Commitments

The following table sets forth information concerning the Company's obligations under non-cancelable long-term operating leases at December 31, 2002, which primarily consist of rental agreements for building space, data processing equipment and vehicles, including major work equipment (in millions).

2003	$ 11
2004	11
2005	11
2006	10
2007	10
2008 and beyond	57
Total	$110

Total lease expense for all operating leases was $10 million, $10 million and $11 million during 2000, 2001 and 2002, respectively.

(c) Environmental, Legal and Other

Clean Air Standards. Based on current limitations of the Texas Commission on Environmental Quality (TCEQ) regarding emission of oxides of nitrogen (NOx) in the Houston area, the Company anticipates investing up to $682 million for emission control equipment through 2005, including $551 million expended from January 1, 1999 through December 31, 2002, with possible additional expenditures after 2005. NOx control estimates for 2006 and 2007 have not been finalized.

The Texas Utility Commission has determined that the Company's emission control plan is the most effective control option. In addition, the Company is required to provide $16.2 million in funding for certain NOx reduction projects associated with East Texas pipeline companies.

Nuclear Insurance. The Company and the other owners of the South Texas Project maintain nuclear property and nuclear liability insurance coverage as required by law and periodically review available limits and coverage for additional protection. The owners of the South Texas Project currently maintain $2.75 billion in property damage insurance coverage, which is above the legally required minimum, but is less than the total amount of insurance currently available for such losses.

Under the Price Anderson Act, the maximum liability to the public of owners of nuclear power plants was $9.3 billion as of December 31, 2002. Owners are required under the Price Anderson Act to insure their liability for nuclear incidents and protective evacuations. The Company and the other owners currently maintain the required nuclear liability insurance and participate in the industry retrospective rating plan under which the owners of the South Texas Project are subject to maximum retrospective assessments in the aggregate per incident of up to $88 million per reactor. The owners are jointly and severally liable at a rate not

to exceed $10 million per incident per year. In addition, the security procedures at this facility have recently been enhanced to provide additional protection against terrorist attacks.

There can be no assurance that all potential losses or liabilities associated with the South Texas Project will be insurable, or that the amount of insurance will be sufficient to cover them. Any substantial losses not covered by insurance would have a material effect on the Company's financial condition, results of operations and cash flows.

Nuclear Decommissioning. The Company is the beneficiary of the decommissioning trust that has been established to provide funding for decontamination and decommissioning of the South Texas Project in which the Company owns a 30.8% interest (see Note 5). CenterPoint Houston collects, through rates or other authorized charges to its electric utility customers, amounts designated for funding the decommissioning trust, and pays the amounts to the Company. CenterPoint Energy deposits these amounts into the decommissioning trust. Upon decommissioning of the facility, in the event funds from the trust are inadequate, CenterPoint Houston or its successor will be required to collect through rates or other authorized charges to customers as contemplated by the Texas Utilities Code all additional amounts required to fund the Company's obligations relating to the decommissioning of the facility. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trust, the excess will be refunded to the ratepayers of CenterPoint Houston or its successor. CenterPoint Energy is contractually obligated to indemnify Texas Genco from and against any obligations relating to the decommissioning not otherwise satisfied through collections by CenterPoint Houston.

Joint Operating Agreement with City of San Antonio. The Company has a joint operating agreement with the City Public Service Board of San Antonio (CPS) to share savings from the joint dispatching of each party's generating assets. Dispatching the two generating systems jointly results in savings of fuel and related expenses because there is a more efficient utilization of each party's lowest cost resources. The two parties equally share the savings resulting from joint dispatch. The agreement terminates in 2009.

(d) Option to Purchase CenterPoint Energy's Interest in the Company

Reliant Resources has an option (Reliant Resources Option) to purchase all of the shares of common stock of the Company owned by CenterPoint Energy. The Reliant Resources Option may be exercised between January 10, 2004 and January 24, 2004. The per share exercise price under the option will equal the average daily closing price on the national exchange for publicly held shares of common stock of the Company for the 30 consecutive trading days with the highest average closing price for any 30 day trading period during the last 120 trading days ending January 9, 2004, plus a control premium, up to a maximum of 10%, to the extent a control premium is included in the valuation determination made by the Texas Utility Commission relating to the market value of the Company. The per share exercise price is also subject to adjustment based on the difference between the per share dividends paid to CenterPoint Energy during the period from January 6, 2003 through the option closing date and the Company's actual per share earnings during that period. Reliant Resources has agreed that if it exercises the Reliant Resources Option and purchases the shares of the Company's common stock, Reliant Resources will also purchase from CenterPoint Energy all notes and other payables owed by the Company to CenterPoint Energy as of the option closing date, at their principal amount plus accrued interest. Similarly, if there are notes or payables owed to the Company by CenterPoint Energy as of the option closing date, Reliant Resources will assume those obligations in exchange for a payment from CenterPoint Energy of an amount equal to the principal plus accrued interest.

In the event that Reliant Resources exercises the Reliant Resources Option in 2004, the Company would be required to step up or step down the tax basis in all of its assets following the date of the sale to be equivalent generally to the value of the equity of the Company (based upon the purchase price) plus the principal amount of the Company's indebtedness at the time of the purchase. The resulting step-up or step-

down in the basis of the Company's assets would impact its future tax liabilities. A step-up would reduce the Company's future tax liabilities, while a step-down would increase its liabilities. The Company cannot currently project the impact of this tax election because it is dependent on (1) Reliant Resources' exercise of its option in 2004, and (2) the purchase price to be paid by Reliant Resources in 2004, which is not known at this time.

Exercise of the Reliant Resources Option by Reliant Resources will be subject to various regulatory approvals, including Hart-Scott-Rodino antitrust clearance and United States Nuclear Regulatory Commission license transfer approval.

(9) Unaudited Quarterly Information

Summarized quarterly financial data is as follows:

	Year Ended December 31, 2001			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
		(in millions)		
Revenues	$977	$957	$898	$579
Operating income	29	95	116	25
Net income	5	49	71	3

	Year Ended December 31, 2002			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
		(in millions)		
Revenues	$326	$414	$526	$275
Operating income (loss)	(52)	(29)	7	(59)
Net income (loss)	(29)	(24)	3	(43)

(10) Guarantor Disclosures

As part of its normal business operations, Texas Genco, LP, a wholly owned subsidiary, has also entered into power purchase and sale agreements to buy less expensive power than Texas Genco's marginal cost of generation or to sell power to another party who is willing to pay more than Texas Genco's marginal cost of generation. Texas Genco has guaranteed the payment obligations of Texas Genco, LP under certain of these agreements, typically for a one-year term. As of December 31, 2002, Texas Genco had delivered 7 such guarantees with an aggregate maximum potential exposure of $28.2 million and an aggregate carrying amount of $-0-.

CenterPoint Energy has delivered guarantees in support of Texas Genco's obligations to ERCOT under qualified scheduling entity and transmission congestion rights agreements. These guarantees expire in October, 2003 and as of December 31, 2002, have an aggregate maximum potential exposure of $45 million and an aggregate carrying amount of $-0-.

(11) Subsequent Event

On February 7, 2003, the Company's board of directors declared an initial quarterly cash dividend of $0.25 per share of common stock payable on March 20, 2003 to shareholders of record as of the close of business on February 26, 2003.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of Texas Genco Holdings, Inc.:

We have audited the accompanying consolidated balance sheets of Texas Genco Holdings, Inc., (the Company), an indirect wholly-owned subsidiary of CenterPoint Energy, Inc., as of December 31, 2001 and 2002, and the related statements of consolidated operations, cash flows and capitalization and shareholder's equity for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2001 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2003

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

The information called for by Item 10, to the extent not set forth in "Executive Officers" in Item 1 of this Form 10-K, is or will be set forth in the definitive proxy statement relating to Texas Genco's 2003 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 10 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 11. ***Executive Compensation.***

The information called for by Item 11 is or will be set forth in the definitive proxy statement relating to Texas Genco's 2003 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 11 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

The information called for by Item 12 is or will be set forth in the definitive proxy statement relating to Texas Genco's 2003 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 13. ***Certain Relationships and Related Transactions.***

The information called for by Item 13 is or will be set forth in the definitive proxy statement relating to Texas Genco's 2003 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 13 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

PART IV

Item 14. ***Controls and Procedures.***

Within the 90 days prior to the date of this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-14 of the Securities Exchange Act of 1934. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting them to material information relating to us (including our consolidated subsidiaries) required to be included in our periodic SEC filings. Subsequent to the date of their evaluation, there were no significant changes in our internal controls or in other factors that could significantly affect the internal controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

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

(a)(1) *Financial Statements.*

(a)(2) *Financial Statement Schedules for the Three Years Ended December 31, 2002.*

The following schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements:

I, II, III, IV and V.

(a)(3) *Exhibits*

See Index of Exhibits on page 73.

(b) *Reports on Form 8-K*

On December 23, 2002, we filed a Current Report on Form 8-K dated December 20, 2002, containing Item 5 disclosure reporting that the Board of Directors of CenterPoint Energy had declared a stock distribution of approximately 19% of the 80,000,000 outstanding shares of Texas Genco common stock to CenterPoint Energy shareholders to take place on January 6, 2003.

On January 7, 2003, we filed a Current Report on Form 8-K dated January 6, 2003, containing Item 5 disclosure reporting that CenterPoint Energy had distributed approximately 19% of the 80,000,000 outstanding shares of Texas Genco common stock to CenterPoint Energy's common shareholders of record as of the close of business on December 20, 2002.

On January 27, 2003, we filed a Current Report on Form 8-K dated January 27, 2003, containing Item 5 disclosure reporting that executives of Texas Genco had hosted a live webcast of a conference call at 1:30 p.m. CST in which they presented a general overview of Texas Genco's business.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the twelfth day of March, 2003.

TEXAS GENCO HOLDINGS, INC.
(Registrant)

By: /s/ DAVID G. TEES
David G. Tees
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 12, 2003.

Signature	Title
/s/ DAVID G. TEES (David G. Tees)	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ GARY L. WHITLOCK (Gary L. Whitlock)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ JAMES S. BRIAN (James S. Brian)	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ DAVID M. MCCLANAHAN (David M. McClanahan)	Director

CERTIFICATIONS

I, David G. Tees, certify that:

1. I have reviewed this annual report on Form 10-K of Texas Genco Holdings, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

    a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

    b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

    c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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

    a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 12, 2003

By: /s/ DAVID G. TEES

David G. Tees
President and Chief Executive Officer

I, Gary L. Whitlock, certify that:

1. I have reviewed this annual report on Form 10-K of Texas Genco Holdings, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 12, 2003

By: /s/ GARY L. WHITLOCK

Gary L. Whitlock
Executive Vice President and
Chief Financial Officer

TEXAS GENCO HOLDINGS, INC.

EXHIBITS TO THE ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2002

INDEX OF EXHIBITS

Exhibits not incorporated by reference to a prior filing are designated by a cross (†); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
†3.1	— Amended and Restated Articles of Incorporation			
†3.2	— Amended and Restated Bylaws			
4.1	— Specimen Stock Certificate	Texas Genco Holdings, Inc.'s ("Texas Genco") registration statement on Form 10	001-31449	4.1
†10.1	— Separation Agreement between CenterPoint Energy, Inc. ("CenterPoint Energy") and Texas Genco effective as of August 31, 2002			
10.2	— Texas Genco Option Agreement	CenterPoint Energy Houston Electric, LLC's (formerly Reliant Energy, Incorporated) ("REI") quarterly report on Form 10-Q for the quarter ended March 31, 2001	1-3187	10.4
†10.3	— Transition Services Agreement between CenterPoint Energy and Texas Genco effective as of August 31, 2002			
10.4	— Technical Services Agreement	CenterPoint Houston's quarterly report on Form 10-Q for the quarter ended March 31, 2001	001-31449	10.3
†10.5	— Tax Allocation Agreement between CenterPoint Energy and Texas Genco effective as of August 31, 2002			
10.6(a)	— Executive Benefit Plan of CenterPoint and First and Second Amendments thereto effective as of June 1, 1982, July 1, 1984 and May 7, 1986, respectively	Houston Industries Incorporated's ("HI") Form 10-Q for the quarter ended March 31, 1987	1-7629	10(a)(1),(a)(2) and (a)(3)
10.6(b)	— Third Amendment to Exhibit 10.6(a) dated September 17, 1999	REI's Form 10-K for the year ended December 31, 2000	1-3187	10(a)(2)
10.7(a)	— Executive Life Insurance Plan of CenterPoint effective as of January 1, 1994	HI's Form 10-K for the year ended December 31, 1993	1-7629	10(q)

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10.7(b)	— First Amendment to Exhibit 10.7(a) effective as of January 1, 1994	HI's Form 10-Q for the quarter ended June 30, 1995	1-7629	10
10.7(c)	— Second Amendment to Exhibit 10.7(a) effective as of August 6, 1997	REI's Form 10-K for the year ended December 31, 1997	1-3187	10(s)(3)
10.8(a)	— Long-Term Incentive Compensation Plan of CenterPoint effective as of January 1, 1989	HI's Form 10-Q for the quarter ended June 30, 1989	1-7629	10(c)
10.8(b)	— First Amendment to Exhibit 10.8(a) effective as of January 1, 1990	HI's Form 10-K for the year ended December 31, 1989	1-7629	10(f)(2)
10.8(c)	— Second Amendment to Exhibit 10.8(a) effective as of December 22, 1992	HI's Form 10-K for the year ended December 31, 1992	1-7629	10(u)(3)
10.8(d)	— Third Amendment to Exhibit 10.8(a) effective as of August 6, 1997	REI's Form 10-K for the year ended December 31, 1997	1-3187	10(m)(4)
10.9	— Retention Agreement effective October 15, 2001 between REI and David G. Tees	REI's Form 10-K for the year ended December 31, 2001	1-3187	10(jj)
10.10(a)	— Deferred Compensation Plan of CenterPoint effective as of January 1, 1991	HI's Form 10-K for the year ended December 31, 1990	1-7629	10((d)(3)
10.10(b)	— First Amendment to Exhibit 10.10(a) effective as of January 1, 1991	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(j)(2)
10.10(c)	— Second Amendment to Exhibit 10.10(a) effective as of March 30, 1992	HI's Form 10-Q for the quarter ended March 31, 1992	1-7629	10(g)
10.10(d)	— Third Amendment to Exhibit 10.10(a) effective as of June 2, 1993	HI's Form 10-K for the year ended December 31, 1993	1-7629	10(j)(4)
10.10(e)	— Fourth Amendment to Exhibit 10.10(a) effective as of December 1, 1993	HI's Form 10-K for the year ended December 31, 1993	1-7629	10(j)(5)
10.10(f)	— Fifth Amendment to Exhibit 10.10(a) effective as of September 7, 1994	HI's Form 10-K for the year ended December 31, 1994	1-7629	10(j)(6)
10.10(g)	— Sixth Amendment to Exhibit 10.10(a) effective as of August 1, 1995	HI's Form 10-Q for the quarter ended June 30, 1995	1-7629	10(b)
10.10(h)	— Seventh Amendment to Exhibit 10.10(a) effective as of December 1, 1995	HI's Form 10-Q for the quarter ended June 30, 1996	1-7629	10(d)

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10.10(i)	— Eighth Amendment to Exhibit 10.10(a) effective as of January 1, 1997	HI's Form 10-Q for the quarter ended June 30, 1997	1-7629	10(d)
10.10(j)	— Ninth Amendment to Exhibit 10.10(a) effective in part August 6, 1997, in part October 1, 1997 and in part January 1, 1998	REI's Form 10-K for the year ended December 31, 1997	1-3187	10(1)(10)
10.10(k)	— Tenth Amendment to Exhibit 10.10(a) effective as of September 3, 1997	REI's Form 10-K for the year ended December 31, 1997	1-3187	
10.11	— Assignment and Assumption Agreement for the Technical Services Agreement entered into as of August 31, 2002, by and between Texas Genco, LP and REI	Texas Genco's registration statement on Form 10	1-31449	10.11
10.12	— Undertaking to Comply with Certain Provisions of Option Agreement entered into as of August 31, 2002 by Texas Genco	Texas Genco's registration statement on Form 10	1-31449	10.12
†10.13	— Amendment No. 1 to Texas Genco Option Agreement dated February 21, 2003			
21.1	— Subsidiaries of Texas Genco	Texas Genco's registration statement on Form 10	1-31449	21.1

Texas Genco Investor Information

Annual Meeting
The annual meeting of shareholders will be held at 9 a.m., Central time, on May 29, 2003, in the first floor auditorium, 1111 Louisiana Street, Houston, Texas. All shareholders are invited to attend. A formal notice of the meeting will be mailed to shareholders in April with a proxy statement. The proxy statement describes business items to be considered at the annual meeting, and includes a proxy card that you may use to vote on nominees for director and other matters.

Investor Services
CenterPoint Energy Investor Services is the transfer agent, registrar and dividend disbursing agent for Texas Genco common stock. If you have questions about your Texas Genco investor account please contact:

In Houston: (713) 207-3060
Toll Free: (800) 231-6406
Fax: (713) 207-3169

Investor Services representatives are available from 8 a.m. to 4:30 p.m. Central time, Monday through Friday, to help you with questions about Texas Genco common stock.

Investor information may be found on the company's web site at: www.txgenco.com

Information Requests
Call (888) 424-8401 toll-free for additional copies of:
2002 Annual Report (includes Form 10-K)
2003 Proxy statement

Dividend Payments
Common stock dividends are generally paid quarterly in March, June, September and December. Dividends are subject to declaration by the Board of Directors, which establishes the amount of each quarterly common stock dividend and fixes record and payment dates.

Institutional Investors
Security analysts and other investment professionals should contact Investor Relations at (713) 207-6500.

Stock Listing
Texas Genco Holdings, Inc. common stock is traded under the symbol TGN on the New York Stock Exchange.

Auditors
Deloitte & Touche LLP, Houston, Texas

Corporate Offices, Street Address
Texas Genco Holdings, Inc.
1111 Louisiana Street
Houston, Texas 77002

Mailing Address
P.O. Box 2846
Houston, Texas 77252-2846

Telephone: (713) 207-1111

Web Address: www.txgenco.com

Design: Pegasus Design, Inc. www.pegasusdesign.com

TexasGenco

TEXAS GENCO HOLDINGS, INC.

1111 Louisiana St.

Houston, Texas 77002

713-207-1111

ATTACHMENT 2

2002 ANNUAL REPORT OF RELIANT RESOURCES, INC.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K/A

(Mark One)

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

For the fiscal year ended December 31, 2002

or

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

For the transition period from ________ to ________

Commission File Number 1-16455

Reliant Resources, Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	76-0655566
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1111 Louisiana Street Houston, Texas 77002	(713) 497-3000
(Address and Zip Code of Principal Executive Offices)	(Registrant's Telephone Number, Including Area Code)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $.001 per share, and associated rights to purchase Series A Preferred Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the Registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K/A or any amendment to this Form 10-K/A. ☐

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ☒ No ☐

The aggregate market value of the voting stock held by non-affiliates of the Registrant was $433,427,759 as of June 28, 2002 (computed by reference to the closing sale price of the Registrant's common stock on the New York Stock Exchange on that date), using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers. As of June 28, 2002, the Registrant had 289,663,717 shares of common stock outstanding, excluding 10,140,283 shares of common stock held by the Registrant as treasury stock.

Portions of the definitive proxy statement relating to the 2003 Annual Meeting of Stockholders of the Registrant's, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2002, are incorporated by reference in Item 10, Item 11, Item 12 and Item 13 of Part III of this Form 10-K/A.

We hereby amend our original Form 10-K for the year ended December 31, 2002, to include Schedule I—Condensed Financial Information of Reliant Resources, Inc. and Exhibits 4.3 and 10.42. Except for the foregoing, no attempt has been made in this Form 10-K/A to modify or update other disclosures as presented in the original Form 10-K.

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Cautionary Statement Regarding Forward-Looking Information

This Form 10-K/A includes statements concerning expectations, assumptions, beliefs, plans, projections, objectives, goals, strategies and future events or performance that are intended as "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can identify our forward-looking statements by the words "anticipates," "believes," "continue," "could," "estimates," "expects," "forecast," "goal," "intends," "may," "objective," "plans," "potential," "predicts," "projection," "should," "will" and similar words.

We have based our forward-looking statements on management's beliefs and assumptions based on information available at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events and performance may and often do vary materially from actual results. Therefore, actual results may differ materially from those expressed or implied by our forward-looking statements. For more information regarding the risks and uncertainties that could cause our actual results to differ materially from those expressed or implied in our forward-looking statements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors" in Item 7 of this Form 10-K/A.

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to publicly update or revise any forward-looking statements.

Glossary of Terms

In this Form 10-K/A, "Reliant Resources" refers to Reliant Resources, Inc., and "we," "us" and "our" refer to Reliant Resources, Inc. and its subsidiaries, unless we specify or the context indicates otherwise. In addition, the following terms are used in this Form 10-K/A:

Alliance RTO	the proposed RTO for all or parts of Missouri, Illinois, Indiana, Michigan, Ohio, Kentucky, West Virginia, Pennsylvania, Tennessee, Virginia and North Carolina.
APB No. 25	Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."
Bcf	one billion cubic feet of natural gas.
Cal ISO	California Independent System Operator.
Cal PX	California Power Exchange.
CDWR	California Department of Water.
CenterPoint	CenterPoint Energy, Inc., on and after August 31, 2002 and Reliant Energy, Incorporated prior to August 31, 2002.
CenterPoint Plans	CenterPoint Long-Term Incentive Compensation Plan and certain other incentive compensation plans of CenterPoint.
CERCLA	Comprehensive Environmental Response Corporation and Liability Act of 1980.
CFTC	Commodity Futures Trading Commission.
Channelview	Reliant Energy Channelview L.P.
CPUC	California Public Utility Commission.
Distribution	the distribution of approximately 83% of our common stock owned by CenterPoint to its stockholders on September 30, 2002.
EBIT	earnings (loss) before interest expense, interest income and income taxes.

EBITDA	earnings (loss) before interest expense, interest income, income taxes, depreciation and amortization expense.
ECAR	East Central Area Reliability Coordination Council.
ECAR Market	the wholesale electric market operated by ECAR.
EFL	Electricity Facts Label.
EITF	Emerging Issues Task Force.
EITF No. 02-03	EITF No. 02-03, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities."
EITF No. 94-3	EITF No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity."
EITF No. 98-10	EITF No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities."
Enron	Enron Corp. and its subsidiaries.
EPA	Environmental Protection Agency.
ERCOT	Electric Reliability Council of Texas.
ERCOT ISO	ERCOT Independent System Operator.
ERCOT Region	the electric market operated by ERCOT.
ESPP	Reliant Resources Employee Stock Purchase Plan.
EURIBOR	inter-bank offered rate for Euros.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FIN No. 45	FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Direct Guarantees of Indebtedness of Others."
FIN No. 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51."
FPSC	Florida Public Service Commission.
GAAP	United States generally accepted accounting principles.
GridFlorida RTO	the FERC approved RTO for Florida.
GW	gigawatt.
GWh	gigawatt hour.
Headroom	the difference between the price to beat and the sum of (a) the charges, fees and transportation and distribution utility rates approved by the PUCT and (b) the price paid for electricity to serve price to beat customers.
IPO	our initial public offering in May 2001.
ISO	independent system operator.
KWh	kilowatt hour.
LEP	Liberty Electric Power, LLC.
Liberty	Liberty Electric PA, LLC.
LIBOR	London inter-bank offered rated.
MAIN	Mid-America Interconnected Network.
MAIN Market	the wholesale electric market operated by MAIN.
MISO	Midwest Independent Transmission System Operator.
MMbtu	one million British thermal units.
Mmcf	million cubic feet.
MW	megawatt.
MWh	megawatt hour.
NEA	NEA, B.V., formerly the coordinating body for the Dutch electric generating sector.
NLG	Dutch Guilders.
Nuon	N.V. Nuon, a Netherlands-based electricity distributor.

NYISO	New York Independent System Operator.
NY Market	the wholesale electric market operated by NYISO.
Orion Capital	Orion Power Capital, LLC.
Orion MidWest	Orion Power MidWest, L.P.
Orion NY	Orion Power New York, L.P.
Orion Power	Orion Power Holdings, Inc., one of our subsidiaries that we acquired in February 2002.
OTC	over-the-counter market.
PGET	PG&E Energy Trading-Power, L.P.
PJM	PJM Interconnection, LLC.
PJM Market	the wholesale electric market operated by PJM regional transmission organization in all or part of Delaware, the District of Columbia, Maryland, New Jersey and Virginia.
PJM West Market	the wholesale electric market operated by PJM in the Midwest.
Protocols	structure, agreements, tariffs, rules, regulations, mechanisms and requirements that govern rates, terms and conditions for electricity services.
PUCT	Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act of 1935.
QSPE	qualified special purpose entity.
REDB	Reliant Energy Desert Basin, LLC, one of our subsidiaries.
Reliant Energy	Reliant Energy, Incorporated and its subsidiaries.
REMA	Reliant Energy Mid-Atlantic Power Holdings, LLC, one of our subsidiaries, and its subsidiaries.
REPG	Reliant Energy Power Generation, Inc., one of our subsidiaries.
REPGB	Reliant Energy Power Generation Benelux, N.V., one of our subsidiaries.
RERC Corp.	Reliant Energy Resources Corp.
RTO	regional transmission organizations.
RTO West	the FERC approved RTO for Idaho, Montana, Nevada, Oregon, Utah and Washington.
SEC	Securities and Exchange Commission.
SeTrans RTO	the FERC approved RTO for all or parts of Georgia, Alabama, Louisiana, Mississippi, Arkansas and eastern Texas.
SMD	the standard market design for the wholesale electric market proposed by the FERC.
SFAS	Statement of Financial Accounting Standards.
SFAS No. 5	SFAS No. 5, "Accounting for Contingencies."
SFAS No. 87	SFAS No. 87, "Employers' Accounting for Pensions."
SFAS No. 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions."
SFAS No. 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities."
SFAS No. 123	SFAS No. 123, "Accounting for Stock Based Compensation."
SFAS No. 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.
SFAS No. 140	SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities."
SFAS No. 141	SFAS No. 141, "Business Combinations."
SFAS No. 142	SFAS No. 142, "Goodwill and Other Intangible Assets."
SFAS No. 143	SFAS No. 143, "Accounting for Asset Retirement Obligations."

SFAS No. 144	SFAS No. 144, "Accounting for Impairment or Disposal of Long-Lived Assets."
SFAS No. 145	SFAS No. 145, "Rescission of FASB Statements Nos. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections."
SFAS No. 148	SFAS No. 148, "Accounting for Stock Based Compensation—Transition and Disclosure."
Spark spread	the difference between power prices and natural gas fuel costs.
SRP	Saltwater River Project Agricultural Improvement and Power District of the State of Arizona.
TCE	Texas Commercial Energy, a retail electric provider to ERCOT.
Texas electric restructuring law	Texas Electric Choice Plan adopted by the Texas legislature in June 1999.
Texas Genco	Texas Genco Holdings, Inc., a subsidiary of CenterPoint, and its subsidiaries.
Transition Plan	Reliant Resources Transition Stock Plan, governing CenterPoint awards held by our employees.
West Connect RTO	the FERC approved RTO for all or part of Colorado, Arizona, New Mexico and a portion of Texas.

PART I

ITEM 1. *Business.*

Our Business

General

Our business operations consist of the following four business segments:

- Retail energy—provides electricity and related services to retail customers primarily in Texas and acquires and manages the electric energy, capacity and ancillary services associated with supplying these retail customers;
- Wholesale energy—provides electric energy and energy services in the competitive segments of the United States wholesale energy markets;
- European energy—includes power generation assets in the Netherlands and a related trading and origination business; and
- Other operations—includes our venture capital investment portfolio and unallocated corporate costs.

For information about the revenues, operating income, assets and other financial information relating to our business segments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Earnings Before Interest and Income Taxes by Segment" in Item 7 of this Form 10-K/A and note 20 to our consolidated financial statements. For information about the risks and uncertainties relating to our business, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors" in Item 7 of this Form 10-K/A.

Our website address is www.reliant.com. The information on our website is not incorporated into this Form 10-K/A. A copy of this Form 10-K/A will be available on our website. You may request a copy of this Form 10-K/A, at no cost, by writing or telephoning us at 713-497-7000. Our executive offices are located at 1111 Louisiana Street, Houston, Texas 77002.

Formation, IPO and Distribution

In June 1999, the Texas legislature adopted an electric restructuring law that amended the regulatory structure governing electric utilities in Texas in order to allow retail electric competition with respect to all customer classes beginning in January 2002. In response to this legislation, CenterPoint, formerly Reliant Energy, adopted a business separation plan in order to separate its regulated and unregulated operations. Under the business separation plan, we were incorporated in Delaware in August 2000, and CenterPoint transferred substantially all of its unregulated businesses to us. We completed an IPO of approximately 20% of our common stock in May 2001 and received net proceeds from our IPO of $1.7 billion. We used $147 million of the net proceeds of our IPO to repay certain indebtedness that we owed to CenterPoint. We used the remainder of the net proceeds of our IPO for repayment of third party borrowings, capital expenditures, repurchases of our common stock and general corporate purposes. In September 2002, the Distribution was completed and, as a result, we are no longer a subsidiary of CenterPoint. For additional information regarding our IPO, see notes 1 and 10(a) to our consolidated financial statements. For additional information regarding agreements and transactions between us and CenterPoint, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Related-Party Transactions" in Item 7 of this Form 10-K/A and notes 3 and 4 to our consolidated financial statements.

Orion Power Acquisition

In February 2002, we acquired all of the outstanding common stock of Orion Power for $2.9 billion and assumed debt obligations of $2.4 billion. Orion Power is an independent electric power generating company with

a diversified portfolio of generating assets, both geographically across the states of New York, Pennsylvania, Ohio and West Virginia, and by fuel type, including gas, oil, coal and hydro. The Orion Power facilities constitute our New York regional portfolio and the majority of our Midwest regional portfolio. For additional information regarding our acquisition of Orion Power and its operations, see "—Wholesale Energy—New York Region" and "—Midwest Region," in Item 1 and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors" in Item 7 of this Form 10-K/A and note 5(a) to our consolidated financial statements.

Disposition of European Energy Operations

In February 2003, we signed a share purchase agreement to sell our European energy operations to Nuon. Upon consummation of the sale, we expect to receive cash proceeds from the sale of approximately $1.2 billion (Euro 1.1 billion). As additional consideration for the sale, we will also receive 90% of the dividends and other distributions in excess of approximately $115 million (Euro 110 million) paid by NEA to REPGB following the consummation of the sale. The purchase price payable at closing assumes that our European energy operations will have, on the sale consummation date, net cash of at least $121 million (Euro 115 million). If the amount of net cash is less on such date, the purchase price will be reduced accordingly. The sale is subject to the approval of the Dutch and German competition authorities. We anticipate that the consummation of sale will occur in the summer of 2003. For further information regarding the disposition of our European energy operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors" in Item 7 of the Form 10-K/A and note 21(b) to our consolidated financial statements.

Retail Energy

We are a certified retail electric provider in Texas, which allows us to provide electricity to residential, small commercial and large commercial, industrial and institutional customers. In January 2002, we began to provide retail electric service to all customers of CenterPoint that did not take action to select another retail electric provider and to customers that selected us to provide them electric service. All classes of customers of most investor-owned Texas utilities can choose their retail electric provider. The law also allows municipal utilities and electric cooperatives to participate in the competitive marketplace, but to date, none have chosen to do so.

Our retail energy segment provides standardized electricity and related products and services to residential and small commercial customers with an aggregate peak demand for power up to one MW (*i.e.*, small and mid-sized business customers) and offers customized electric commodity and energy management services to large commercial, industrial and institutional customers with an aggregate peak demand for power in excess of one MW (*e.g.*, refineries, chemical plants, manufacturing facilities, real estate management firms, hospitals, universities, school systems, governmental agencies, multi-site retailers, restaurants, and other facilities under common ownership or franchise arrangements with a single franchiser, which aggregate to one MW or greater of peak demand).

We currently provide retail electric service only in Texas. We have no near-term plans to provide retail electric service to residential customers outside of Texas; however, we are taking steps to provide electricity and related products and services to large commercial, industrial and institutional customers in certain other states. In New Jersey, we are registered as an "electric power supplier," and in Pennsylvania, we are registered as an "electric generation supplier."

For information about the risks and uncertainties relating to our retail energy segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Risks Related to Our Retail Energy Operations" in Item 7 of this Form 10-K/A.

Residential and Small Commercial Services

We have approximately 1.5 million residential customers and over 200,000 small commercial accounts in Texas, making us the second largest retail electric provider in Texas. The majority of our customers are in the Houston metropolitan area, but we also have customers in other metropolitan areas, including Dallas and Corpus Christi, Texas.

In general, the Texas regulatory structure permits retail electric providers to procure electricity from wholesale generators at unregulated rates, sell the electricity at generally unregulated prices to retail customers and pay the local transmission and distribution utilities a regulated tariff rate for delivering the electricity to the customers. By allowing retail electric providers to provide retail electricity at any price, the Texas electric restructuring law is designed to encourage competition among retail electric providers. However, retail electric providers which are affiliates of, or successors in interest to, electric utilities are restricted in the prices they may charge to residential and small commercial customers within the affiliated transmission and distribution utility's traditional service territory. We are deemed to be the affiliated retail electric provider in Centerpoint's Houston area service territory, and we are an unaffiliated retail electric provider in all other areas. The prices that affiliated retail electric providers charge are subject to a specified price, or "price to beat" and the affiliated retail electric providers are not permitted to sell electricity to residential and small commercial customers in the service territory of the affiliated transmission and distribution utility at a price other than the price to beat until January 2005, unless before that date 40% or more electricity consumed in 2000 by the relevant class of customers in the affiliated transmission and distribution utility service territory is committed to be served by other retail electric providers. Unaffiliated retail electric providers may sell electricity to residential and small commercial customers at any price.

In addition, the Texas electric restructuring law requires the affiliated retail electric provider to make the price to beat available to residential and small commercial customers in the affiliated transmission and distribution utility's traditional service territory until January 1, 2007. The price to beat only applies to electric services provided to residential and small commercial customers (i.e., customers with an aggregate peak demand at or below one MW).

The PUCT's regulations allow an affiliated retail electric provider to adjust the price to beat based on the wholesale energy supply cost component or "fuel factor" included in its price to beat. The PUCT's current regulations allow us to request an adjustment of our fuel factor based on the percentage change in the forward price of natural gas or as a result of changes in the price of purchased energy up to two times a year. In a purchased energy request, we may adjust the fuel factor to the extent necessary to restore the amount of headroom that existed at the time the initial price to beat fuel factor was set by the PUCT. During 2002, we requested, and the PUCT approved two such adjustments to our price to beat fuel factor. In January 2003, we requested, and the PUCT approved in March 2003, an increase of our price to beat fuel factor. We cannot estimate with any certainty the magnitude and timing of future adjustments required, if any, or the impact of such adjustments on our headroom. To the extent that a requested adjustment is not received on a timely basis, our results of operations, financial condition and cash flows may be adversely affected. For additional information regarding adjustments to our price to beat fuel factor, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—EBIT by Business Segment" in Item 7 of this Form 10-K/A.

In March 2003, the PUCT approved a revised price to beat rule. The changes from the previous rule include an increase in the number of days used to calculate the natural gas price average from ten to 20, and an increase in the threshold of what constitutes a significant change in the market price of natural gas and purchased energy from 4% to 5%, except for filings made after November 15th of a given year that must meet a 10% threshold. The revised rule also provides that the PUCT will, after reaching a determination of stranded costs in 2004, make downward adjustments to the price to beat fuel factor if natural gas prices drop below the prices embedded in the then-current price to beat fuel factor. In addition, the revised rule also specifies that the base rate portion of the price to beat will be adjusted to account for changes in the non-bypassable rates that result from the utilities' final stranded cost determination in 2004. Adjustments to the price to beat will be made following the utilities' final stranded cost determination in 2004.

To the extent that our price to beat for electric service to residential and small commercial customers in CenterPoint's Houston service territory during 2002 and 2003 exceeds the market price of electricity, we may be required to make a significant payment to CenterPoint in 2004. As of December 31, 2002, our estimate for the payment related to residential customers is between $160 million and $190 million, with a most probable estimate of $175 million. For additional information regarding this payment, see note 14(e) to our consolidated financial statements.

Large Commercial, Industrial and Institutional Services

We provide electricity and energy services to large commercial, industrial and institutional customers (*i.e.*, customers with an aggregate peak demand of greater than one MW) in Texas with whom we have signed contracts. As of December 31, 2002, the average contract term for these contracts was 15 months. In addition, we provide electricity to those large commercial, industrial and institutional customers in CenterPoint's service territory who have not entered into a contract with any retail electric provider. We also provide customized energy solutions, including risk management and energy services products, and demand side and energy information services to our large commercial, industrial and institutional customers.

Our large commercial, industrial and institutional customers include refineries, chemical plants, manufacturing facilities, real estate management firms, hospitals, universities, school systems, governmental agencies, multi-site retailers, restaurants, and other facilities under common ownership or franchise arrangements with a single franchiser, which aggregate to one MW or greater of peak demand. Excluding those parts of Texas not currently open to competition, the large commercial, industrial and institutional segment in Texas consists of approximately 2,700 buying organizations consuming an estimated aggregate of approximately 17,000 MW of electricity at peak demand. Our contracts with customers represent a peak demand of approximately 5,500 MW at approximately 24,000 metered locations.

Provider of Last Resort

In Texas, a provider of last resort is required to offer a standard retail electric service with no interruption of service, except in the event of non-payment, to any customer requesting electric service, to any customer whose certified retail electric provider has failed to provide electric service or to any customer that voluntarily requests this type of service. Through a competitive bid process administered by the PUCT, we were appointed to serve as the provider of last resort in many regions of the state. We do not expect to serve a large number of customers in this capacity, as many customers are expected to subsequently select a retail electric provider. We will serve a two-year term as the provider of last resort ending December 31, 2004. Pricing for service provided by a provider of last resort may include a customer charge and an energy charge, which for residential and small commercial customers is adjustable based upon changes in the forward price of natural gas. For large non-residential customers, the energy charge is adjusted based upon the ERCOT market-clearing price of energy. For all customer classes, the adjustment to the energy charge is subject to a floor amount. Non-residential customers will be assessed a demand charge.

Retail Energy Supply

We continuously monitor and update our retail energy supply positions based on our retail energy demand forecasts and market conditions. We enter into bilateral contracts with third parties for electric energy, capacity and ancillary services.

Texas Genco (currently 81% owned by CenterPoint), which owns approximately 13,900 MW of aggregate net generation capacity in Texas, is our primary source of retail energy capacity.

The generating capacity of the Texas Genco facilities consists of approximately 60% of base-load, 35% of intermediate and 5% of peaking capacity, and represents approximately 20% of the total capacity in ERCOT. To

facilitate a competitive market in Texas, each power generator affiliated with a transmission and distribution utility must sell at auction 15% of the output of its installed generating capacity. These auction obligations will continue until January 2007, unless at least 40% of the electricity consumed by residential and small commercial customers in CenterPoint's service territory is being served by retail electric providers other than us. An affiliated retail electric provider may not purchase capacity sold by its affiliated power generation company in the state mandated capacity auctions. Therefore, we are prohibited from participating in the Texas Genco capacity auctions mandated by the PUCT. We may purchase capacity from non-affiliated parties, other than Texas Genco, in the capacity auctions mandated by the PUCT. Under an agreement between us and CenterPoint, Texas Genco is required to auction the remaining 85% of its capacity. We have the right to purchase 50% (but not less than 50%) of such remaining capacity at the prices established in such auctions. We also have the right to participate directly in such auctions.

We have an option to acquire CenterPoint's ownership interest in Texas Genco that is exercisable from January 10, 2004 until January 24, 2004. Texas Genco's obligation to auction its capacity and our associated rights terminate (a) if we do not exercise our option to acquire CenterPoint's ownership interest in Texas Genco by January 24, 2004 and (b) if we exercise our option to acquire CenterPoint's ownership interest in Texas Genco, on the earlier of (i) the closing of the acquisition or (ii) if the closing has not occurred, the last day of the sixteenth month after the month in which the option is exercised. For additional information regarding our option to acquire Texas Genco, see note 4(b) to our consolidated financial statements.

ERCOT

We are a member of ERCOT. The ERCOT ISO is responsible for maintaining reliable operations of the bulk electric power supply system in the ERCOT Region. Its responsibilities include ensuring that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to anyone needing the information. It is also responsible for ensuring that electricity production and delivery are accurately accounted for among the generation resources and wholesale buyers and sellers in the ERCOT Region. Unlike some independent system operators in other regions of the country, the ERCOT ISO does not operate a centrally dispatched pool and does not procure energy on behalf of its members other than to maintain the reliable operation of the transmission system. Members are responsible for contracting their energy requirements bilaterally. The ERCOT ISO also serves as agent for procuring ancillary services for those who elect not to secure their own ancillary services requirement.

Members of ERCOT include retail customers, investor and municipal owned electric utilities, rural electric cooperatives, river authorities, independent generators, power marketers and retail electric providers. The ERCOT Region operates under the reliability standards set by the North American Electric Reliability Council. The PUCT has primary jurisdictional authority over the ERCOT Region to ensure the adequacy and reliability of electricity across the state's main interconnected power grid.

The ERCOT Region is divided into four congestion zones: north, south, west and Houston. While most of our retail demand and associated supply is located in the Houston congestion zone, we serve customers and acquire supply in all four congestion zones. In addition, ERCOT conducts annual and monthly auctions of transmission congestion rights which provide the entity owning transmission congestion rights the ability to financially hedge price differences between zones (basis risk). The PUCT prohibits any single ERCOT market participant from owning more than 25% of the available transmission congestion rights on any congestion path.

For information regarding our generating facilities in the ERCOT Region, see "Our Business—Wholesale Energy—ERCOT Region."

Competition

For information regarding competitive factors affecting our retail energy segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Risk Factors – Risks Related to Our Retail Energy Operations" in Item 7 of this Form 10-K/A.

Wholesale Energy

Our wholesale energy segment provides energy and energy services with a focus on the competitive wholesale segment of the United States energy industry. We have built a portfolio of electric power generation facilities, through a combination of acquisitions and development, that are not subject to traditional cost-based regulation; therefore, we can generally sell electricity at prices determined by the market, subject to regulatory limitations. We trade and market electricity, natural gas, natural gas transportation capacity and other energy-related commodities. We also optimize our physical assets and provide risk management services for our asset portfolio. In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions. For information about the risks and uncertainties relating to our wholesale energy segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Risks Related to Our Wholesale Energy Operations" in Item 7 of this Form 10-K/A.

Overview of Wholesale Energy Market

Over the past two years, the wholesale energy markets in the United States have undergone dramatic changes. In late 2000 into early 2001, power markets across most of the United States were trading at historical highs due in large part to tight wholesale power market conditions, gas prices being at record levels because of falling supplies and strong demand from a growing economy, gas trading volumes continuing their rapid growth, and power trading and generation companies having substantial access to the debt and equity markets. However, during the summer of 2001, market conditions began to take a downward turn when the first significant wave of nearly 200,000 MW of new generating capacity commenced operations and began to ease the tight wholesale power market conditions. Also, state regulators, in concert with the FERC, began to impose price caps and other marketplace rules that resulted in power and ancillary service prices in certain markets being at or near the variable cost to provide them. Energy trading activity also saw a sharp reversal during 2001. The failure of certain energy companies damaged the reputation of the entire industry and energy trading specifically. The heightened attention on energy trading businesses and the subsequent findings and allegations of questionable business practices and transactions engaged in by a number of industry participants, including us, caused a further erosion of confidence in the industry. As a result, liquidity in the market began to decline.

The overall market conditions in the wholesale power industry continued to worsen during 2002. With the addition of still more generation capacity and heightened regulatory oversight, power prices continued their downward trend, trading at or barely above the variable cost of production in many markets. Confronted with a weaker profit outlook in both electric generation and energy trading and significant amounts of short-term debt to be refinanced, credit agencies began a series of downgrades of substantially all the industry's major market participants, leaving many with below investment grade credit ratings. These downgrades severely curtailed the access of these companies to the debt or equity markets and triggered credit collateral requirements relating to their trading and hedging activities. Consequently, many companies were forced to significantly reduce their trading activities, which further reduced market liquidity.

During the second half of 2002 and continuing into 2003, investors and government regulators, as well as many industry participants and independent observers urged industry reforms to provide more balanced and sustainable long-term market conditions in both the power markets and the energy trading markets. The most significant of these are the FERC's efforts to implement SMD and industry efforts to develop clearing and settlement provisions at energy exchanges that would greatly reduce collateral requirements of participating companies.

Power Generation Operations

We own, own an interest in, or lease 128 operating electric power generation facilities with an aggregate net generating capacity of 19,888 MW located in six regions of the United States. The generating capacity of these

facilities consists of approximately 34% of base-load, 35% of intermediate and 31% of peaking capacity. We have two electric power generation facilities and three replacement or incremental electric power generation units at existing facilities, or 2,461 MW of net generating capacity, under construction.

The following table describes our electric power generation facilities and net generating capacity by region:

Region	Number of Generation Facilities (1)	Total Net Generating Capacity (MW) (2)	Dispatch Type (3)	Fuel Type
Mid-Atlantic				
Operating (4)	22	4,227	Base, Intermediate, Peak	Gas/Coal/Oil/Hydro
Under Construction (6)(7)(8)(9)	—	1,120	Base, Intermediate, Peak	Gas/Oil/Coal
Combined	22	5,347		
New York				
Operating (5)	77	2,952	Base, Intermediate, Peak	Gas/Oil/Hydro
Midwest				
Operating	10	5,052	Base, Intermediate, Peak	Gas/Oil/Coal
Southeast				
Operating (10)(11)	5	2,210	Base, Intermediate, Peak	Gas/Oil
Under Construction (6)(7)	1	800	Intermediate, Peak	Gas
Combined	6	3,010		
West				
Operating (12)(13)	7	4,642	Base, Intermediate, Peak	Gas/Oil
Under Construction (6)	1	541	Base, Intermediate, Peak	Gas
Combined	8	5,183		
ERCOT				
Operating	7	805	Base	Gas/Landfill Gas
Total				
Operating	128	19,888		
Under Construction	2	2,461		
Combined	130	22,349		

(1) Unless otherwise indicated, we own a 100% interest in each facility listed.

(2) Average summer and winter net generating capacity.

(3) We use the designations "Base," "Intermediate," and "Peak" to indicate whether the facilities described are base-load, intermediate, or peaking facilities, respectively.

(4) We lease a 100%, 16.67% and 16.45% interest in three Pennsylvania facilities having 614 MW, 284 MW and 282 MW of net generating capacity, respectively, through facility lease agreements having terms of 26.5 years, 33.75 years and 33.75 years, respectively.

(5) Excludes two hydro plants with a net generating capacity of 5 MW, which are not currently operational.

(6) We consider a project to be "under construction" once we have acquired the necessary permits to begin construction, broken ground on the project site and contracted to purchase machinery for the project, including the combustion turbines.

(7) Our two construction projects in the Mid-Atlantic region and one of our projects in the Southeast region are owned by off-balance sheet special purpose entities as of December 31, 2002 and are being constructed under construction agency agreements (see note 14(b) to our consolidated financial statements).

(8) The 1,120 MW of net generating capacity under construction is based on 1,317 MW of net generating capacity currently under construction, less 197 MW of net generating capacity that will be retired upon completion of one of the projects.

(9) Our two construction projects in the Mid-Atlantic region are replacement or incremental electric power generation units at existing facilities. These units are reflected in the operating generation facilities count, but the net generating capacity of such units will be reflected in the under construction count until the units begin commercial operation.

(10) We own a 50% interest in one of these facilities having a net generating capacity of 108 MW. An independent third party owns the other 50%.

(11) We lease a 100% interest in two Florida facilities having 630 MW and 474 MW of net generating capacity, respectively, through facility lease agreements having terms of 10 years and 5 years, respectively.

(12) Beginning in January 2003, two California generation units having 264 MW of total net generating capacity were idled due to a lack of required environmental permits.

(13) We own a 50% interest in one Nevada facility having a total generating capacity of 470 MW. An independent third party owns the other 50%.

Mid-Atlantic Region

Facilities. We own, own an interest in, or lease 22 operating electric power generation facilities with an aggregate net generating capacity of 4,227 MW located in Pennsylvania, New Jersey and Maryland. The generating capacity of these facilities consists of approximately 38% of base-load, 32% of intermediate and 30% of peaking capacity.

We are constructing a 795 MW gas-fired intermediate and peaking generation unit at an existing facility located in Pennsylvania. We expect this unit will begin commercial operation in the third quarter of 2003. We are also constructing a 522 MW coal-fired base-load unit that will replace two of our generating units at an existing facility located in Pennsylvania. This new unit will add 325 MW of additional generating capacity, net of the 197 MW of generating capacity of the existing units that will be retired upon commencement of commercial operations of the new unit. We expect this unit will begin commercial operation near the end of 2004. These units are being constructed under the terms of a construction agency agreement. For additional information regarding the construction agency agreements, see notes 2(t), 14(b) and 21(a) to our consolidated financial statements. Because of lower price conditions in the PJM Market and the rising cost of operations, particularly with respect to emission costs, we retired an 82 MW coal-fired facility located in our Mid-Atlantic region in September 2002.

Market Framework. We currently sell the power generated by our Mid-Atlantic facilities in the PJM Market and occasionally to buyers in adjacent power markets, such as the ECAR Market and NY Market. We also expect to sell power in a newly created PJM West Market. Each of the PJM, the NY and the PJM West Markets operates as centralized power pools with open-access, non-discriminatory transmission systems. The PJM and PJM West Markets are administered by PJM, a FERC-approved RTO.

Although the transmission infrastructure within these markets is generally well developed and independently operated, transmission constraints exist between, and to a certain extent within, these markets. In particular, transmission of power from western Pennsylvania and upstate New York to eastern Pennsylvania, New Jersey and New York City may be constrained. Depending on the timing and nature of transmission constraints, market prices may vary from market to market, or between sub-regions of a particular market. Market prices are generally higher in New York City than in other parts of New York due to the transmission constraints.

In addition to managing the transmission system, PJM is responsible for maintaining competitive wholesale markets, operating the spot wholesale electric energy, capacity and ancillary services markets and determining the market clearing price based on bids submitted by participating generators in each market. PJM generally matches sellers with buyers within a particular market that meet specified minimum credit standards. We sell electric energy, capacity and ancillary services into the markets maintained by PJM on both a real-time basis and a forward basis for periods of up to one year. Our customers consist of the members of each market, including municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities, retail electric providers and power marketers. We also sell electric energy, capacity and ancillary services to customers in our Mid-Atlantic region under negotiated bilateral contracts.

PJM has an internal market monitor. The internal market monitor reports on issues relating to the operation of the PJM Market, including the determination of transmission congestion costs or the potential of any market participation to exercise market power within the PJM Market or PJM West Market. The internal market monitor evaluates the operation of both spot and bilateral markets to detect either design or structural flaws in the PJM Market and evaluates any proposed enforcement mechanisms that are necessary to assure compliance with the PJM Protocols.

The PJM Protocols allow energy demand to respond to price changes. The lack of sufficient energy demand that may respond has been cited as the primary reason for retaining the electric energy, capacity and ancillary service market caps, which are currently set at $1,000 per MWh in the PJM Market and the energy price mitigation measures in the PJM Market.

Energy market price mitigation measures are implemented for some generating facilities when, in the opinion of PJM, transmission constraints are present. This is commonly referred to as price capping. In such instances, PJM requires, for purposes of system reliability, the dispatch of specific units. In the opinion of PJM, these units are not needed to meet energy demand and are only necessary to maintain the stability of the PJM transmission system. When price capping is imposed, the asking price submitted by these generating facilities is disregarded in setting the PJM market price and the subject units receive a mitigated price that is generally equal to incremental operating costs of the generating unit plus 10%. Historically, 11 generating facilities, representing over 250 MW, in our Mid-Atlantic region have been consistently impacted by this procedure. In addition, a few other generating facilities in our Mid-Atlantic region have experienced occasional price capping during selective hours.

PJM attempts to ensure that there is sufficient generation capacity to meet energy demand and ancillary services requirements through a capacity market. All power retailers are required to demonstrate commitments for capacity sufficient to meet their peak forecasted load plus a reserve above this level, currently set at 18%. Prices for capacity are capped by PJM at approximately $175 per MW per day.

New York Region

Facilities. We own 77 operating electric power generation facilities with an aggregate net generating capacity of 2,952 MW located in New York. Our generating facilities in the New York region consist of two distinct groups, intermediate and peaking facilities located in New York City and, with the exception of one gas-fired facility, 73 small run-of-river hydro facilities located in central and northern New York State. The overall generating capacity of these facilities consists of approximately 23% of base-load, 41% of intermediate and 36% of peaking capacity. With the exception of one facility, all of our New York facilities were acquired as a result of utility divestitures.

Market Framework. We currently sell the power generated by our New York regional facilities in the NY Market. In New York City, we sell electric energy and ancillary services into both day-ahead and real-time markets and capacity in the monthly and six month forward markets. Our customers include municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities, retail electric providers and power marketers. Our hydro facilities are currently under contract to sell all electric energy, capacity and ancillary services to Niagara Mohawk under contract through September 2004.

Our sales into markets administered by NYISO are governed by the NYISO Protocols. The NYISO Protocols allow energy demand to respond to high prices in emergency and non-emergency situations. The lack of sufficient energy demand that may respond to prices has been cited as one of the primary reasons for retaining wholesale energy bid caps, which are currently set at $1,000 per MWh in the NY Market.

The NYISO Protocols established a capacity market in order to ensure that there is enough generation capacity to meet retail energy demand and ancillary services requirements. All power retailers are required to demonstrate commitments for capacity sufficient to meet their peak forecasted load plus a reserve requirement, currently set at 18%. As an additional local reliability measure, power retailers located in New York City are required to procure the majority of this capacity, currently 80% of their peak forecasted load, from generating units located in New York City. Because only a few suppliers own the existing in-city capacity, previously divested utility generation is subject to a capacity price cap. Any generation capacity added following divestiture is not subject to a capacity price cap.

NYISO has implemented a measure known as the "automated mitigation procedure" under which day-ahead energy bids will be automatically reviewed. If bids exceed certain pre-established thresholds and have a significant impact on the market-clearing price, the bids are then reduced to a pre-established market based or negotiated reference bid. NYISO has also adopted, at the FERC's direction, more stringent mitigation measures for all generating facilities in transmission-constrained New York City.

NYISO has an internal market monitoring organization. The market monitor assesses the efficiency and effectiveness of the electric energy, capacity and ancillary services. In performing these functions, the internal market monitor develops reference price levels for each generator, oversees the operation of NYISO's automatic mitigation procedure, investigates potential anti-competitive behavior by market participants, recommends changes in market Protocols and prepares periodic reports for submission to the FERC and other agencies. In addition, NYISO also has an external market advisor that works closely with the market monitor and has the independent authority to suggest changes in Protocols or recommend sanctions or penalties directly to the NYISO governing board. The NYISO market advisor issues written reports containing analyses and recommendations, which are made available to the public.

For additional information on the NY Market, see "Business—Mid-Atlantic Region—Market Framework" in Item 1 of this Form 10-K/A.

Midwest Region

Facilities. We own 10 operating electric power generation facilities with an aggregate net generating capacity of 5,052 MW located in Illinois, Ohio, Pennsylvania and West Virginia. The generating capacity of these facilities consists of approximately 57% of base-load, 6% of intermediate and 37% of peaking capacity.

Market Framework. We generally sell the electric energy, capacity and ancillary services generated and/or provided by our Midwest region portfolio into the PJM West Market, the ECAR Market and the MAIN Market. These markets include all or portions of Illinois, Wisconsin, Missouri, Indiana, Ohio, Michigan, Virginia, West Virginia, Tennessee, Maryland and Pennsylvania. The PJM West Market operates as part of the PJM centralized power pool with open-access, non-discriminatory transmission system administered by an independent system operator approved by the FERC that is responsible for, among other things, maintaining competitive wholesale markets, operating the spot wholesale energy market and determining the market clearing price. For additional information on the PJM Market and the PJM West Market, see "Business—Mid-Atlantic Region—Market Framework" in Item 1 of this Form 10-K/A.

The ECAR and MAIN Markets continue to be in a state of transition and are in the process of establishing RTOs that would define the rules and requirements around which competitive wholesale markets in the region would develop. The FERC has granted RTO status to the MISO, which administers a substantial portion of the transmission facilities in the Midwest region. The FERC has also approved the various RTO selections made by the members of the former Alliance RTO. Some of the members of this group will join the MISO and others will join PJM. The final market structure for the Midwest region remains unsettled. Some states within the ECAR and MAIN Markets have restructured their retail electric power markets to competitive markets from traditional utility monopoly markets, while others have not.

The FERC has also required MISO to engage the services of an independent market monitor. The independent market monitor's duties include monitoring the functioning of the markets run by the MISO to ensure that they are functioning efficiently. This includes identifying factors that might contribute to economic inefficiency such as design flaws, inefficient market rules and barriers to entry. The independent market monitor must also monitor the conduct of individual market participants. MISO is currently waiting on approval by the FERC for a market mitigation plan that resembles the automated mitigation procedure utilized by NYISO.

Our generating facilities located in Pennsylvania, Ohio, and West Virginia straddle the PJM West and other ECAR Markets. Currently, these generating facilities are primarily dedicated to serving the power demands of Duquesne Lighting Company in the greater Pittsburgh area under a contract through December 2004. During periods when the capacity of the generating facilities in our Midwest region exceeds the power demands of the Duquesne Lighting Company, we sell the excess power in the day-ahead markets or to municipalities, electric cooperatives, vertically integrated utilities, transmission and distribution utilities and power marketers.

We currently sell electric energy, capacity and ancillary services from our Illinois generating facilities under bilateral contracts that have terms and conditions tailored to meet the customers' requirements. Our customers include municipalities, electric cooperatives, vertically integrated utilities, transmission and distribution utilities and power marketers.

Southeast Region

Facilities. We own, own an interest in, or lease five power generation facilities with an aggregate net generating capacity of 2,210 MW located in Florida and Texas. The generating capacity of these facilities consists of approximately 2% of base-load, 27% of intermediate and 71% of peaking capacity.

We are constructing an 800 MW gas-fired intermediate and peaking facility in Mississippi. We expect this facility will begin commercial operation in the third quarter of 2003. This facility is being constructed under the terms of a construction agency agreement. For additional information regarding the construction agency agreement, see note 14(b) to our consolidated financial statements.

Market Framework. We currently conduct the majority of our Southeast regional operations in Florida. Florida, other than a portion of the western panhandle, constitutes a single reliability council and contains approximately 5% of the United States population. Although dominated by incumbent utilities, Florida is in the process of transitioning to a competitive wholesale generation market by developing rules for new capacity procurement and establishing the GridFlorida RTO. The FPSC has implemented new capacity procurement rules that require utilities to seek bids to purchase electricity from independent power producers and other utilities before embarking on self-build options for new capacity requirements. Additionally, the FPSC has approved a proposal to increase the level of planning reserve capacity from 15% to 20%. This new criterion applies to the three investor-owned utilities operating in peninsular Florida and becomes effective in the summer of 2004.

The Florida markets are expected to be administered by the GridFlorida RTO. For the past year, the Grid Florida RTO's activities have focused on concerns expressed by the FPSC. However, recent progress has been slow due to a legal challenge by the state's consumer advocate division, which is disputing the FPSC's authority to authorize the transfer of assets to an RTO. A decision on this matter may not be reached until early 2004. At this time, the GridFlorida RTO has not finalized its proposal for market monitoring, but it will be obligated to establish a market monitor.

We currently sell electric energy and capacity into the Florida market primarily under bilateral contracts that are non-standard and negotiated for terms and conditions. An OTC trading and ancillary services market has yet to fully develop. Customers who participate in power transactions in this region include municipalities, electric cooperatives and integrated utilities.

In the rest of the Southeast Region, RTO formation is occurring under the auspices of the SeTrans RTO. The SeTrans RTO will cover the area from Georgia to eastern Texas. While the FERC has currently approved the basic formation of this entity, significant details of this market will not be known until mid or late 2003. Because the SeTrans RTO is still in the formative stages of development, it has only recently begun the process of selecting the independent entity that will become its market monitor.

West Region

Facilities. We own, or own an interest in, seven electric power generation facilities with an aggregate net generating capacity of 4,642 MW located in California, Nevada and Arizona. The generating capacity of these facilities consists of approximately 18% of base-load, 75% of intermediate and 7% of peaking capacity. We are constructing a 541 MW gas-fired, base-load, intermediate and peaking generation facility in southern Nevada. We expect this facility will begin commercial operation in the fourth quarter of 2003.

Market Framework. Our West regional market includes the states of Arizona, California, Oregon, Nevada, New Mexico, Utah and Washington. Generally we sell the electric energy, capacity and ancillary services generated and/or provided by our California and Nevada facilities to customers located in the greater Los Angeles metropolitan area and in southern Nevada. We believe that our portfolio of intermediate and peaking facilities in southern California is important to the reliability of the California market given its production flexibility and close proximity to Los Angeles. Our customers in these states include power marketers, investor-owned utilities, electric cooperatives, municipal utilities and the Cal ISO acting on behalf of load-serving entities. We sell electric energy, capacity and ancillary services to these customers through a combination of bilateral contracts and sales made in the Cal ISO's day-ahead and hour-ahead ancillary services markets and its real-time energy market. The Cal ISO does not currently maintain a capacity market to ensure resource adequacy; however, California regulatory authorities are in the process of developing such a mechanism.

We have agreed to sell up to 100% of our 588 MW operating Arizona facility's capacity to SRP under a long-term power purchase agreement. In addition, although we do not own generation facilities in the states of Oregon, New Mexico, Utah and Washington, our trading and marketing operations have historically purchased and delivered energy commodities in these states.

Two units at our Etiwanda facility in California totaling 264 MW of intermediate capacity, under their current configuration, do not satisfy the more stringent emissions standards that went into effect in 2003. We will evaluate the California capacity market in the second quarter of 2003 and determine whether to make the investment in the necessary environmental upgrades or retire the units.

In response to California's energy crisis of 2000 and 2001, the FERC and the Cal ISO have instituted energy price caps, formerly set below $100 per MWh and currently set at $250 per MWh, and must-offer requirements affecting all merchant generators in California. Furthermore, the Western region has seen significant new generation capacity become operational as well as a return to more normal hydro and temperature conditions. The impact of these regulatory and market changes has been to significantly lower power prices and spark spreads in the West region.

The Cal ISO has a department of market analysis that acts as its internal market monitor. The department of market analysis monitors the efficiency and effectiveness of the ancillary services, congestion management and real-time energy markets. In performing these functions, the department of market analysis develops and publishes market performance indices, investigates potential anti-competitive behavior by market participants, recommends changes in market rules and protocols, and prepares periodic reports for submission to the FERC and other agencies. In addition to the department of market analysis, the Cal ISO also has a market surveillance committee that acts as its external advisor. The market surveillance committee works closely with the department of market analysis and has the independent authority to suggest changes in Cal ISO Protocols or recommend sanctions or penalties directly to the Cal ISO governing board. The market surveillance committee periodically produces written reports containing its analyses and recommendations, which are made available to the public subject to restrictions on confidential information. The Cal ISO has initiated, at the FERC's direction, automated mitigation procedures when any zonal clearing price for balancing energy exceeds $91.87 per MWh with any resulting zonal clearing price subject to the price cap of $250 per MWh. The automated mitigation procedures are only applied to bids that exceed certain reference prices and that would significantly increase the market price. However, in February 2003, the Cal ISO stated that it intends to appeal the FERC's decision regarding the application of automated mitigation procedures to local market power situations. While the FERC had adopted similar thresholds for both local and system market power, the Cal ISO is seeking to have a more restrictive procedure applied to local market power.

A number of initiatives currently under consideration could materially impact our California operations. These initiatives include:

- a California law directing the CPUC to seek approval from the FERC to allow the CPUC to enforce state-established maintenance and operation standards of our California plants;
- implementation of a CPUC procurement process directing California utilities to procure, on a forward basis, electricity and capacity to serve the demand on their systems;
- efforts by the Cal ISO to redesign the spot markets in California; and
- the effect of the FERC's SMD effort, including its impact on the FERC approved western RTOs.

For additional information regarding SMD, see "Business—Wholesale Energy—Regulatory" in Item 1 of this Form 10-K/A.

In Nevada and Arizona, there is presently no RTO in place to manage the transmission systems or to operate energy markets, although the utilities in both states are participating in the development of RTOs. The West Connect RTO, which includes Arizona, and the RTO West, which includes Nevada, have both been approved by the FERC and are in process of developing operating rules and tariffs. Both RTOs are expected to be operational and assume control over transmission of facilities of participating utilities within the next several years. The FERC has also approved the establishment of market monitoring organizations as part of RTO West and West Connect RTO. The FERC is encouraging the RTOs to coordinate in the development of a region-wide market monitoring function. Additionally, in Nevada and Arizona, state-level regulatory initiatives may impact competition in the electric sector. In Nevada, the state legislature has passed legislation prohibiting the state's investor-owned utilities from divesting generation. Nevada also passed legislation and adopted regulations allowing large commercial and industrial customers to seek competitive alternatives to utility generation. In Arizona, proceedings are pending before the Arizona Corporate Commission that would require the state's investor owned utilities to seek competitive supply offers to serve 2,500 to 3,200 MW of local system demand.

ERCOT Region

Facilities. We own seven power generation units at two facilities with an aggregate net generating capacity of 805 MW located in Texas. The generating capacity of these facilities consists of 100% base-load capacity.

Market Framework. For information regarding the market framework in the ERCOT region, see "Business—Retail Energy—Retail Energy Supply."

Long-term Purchase and Sale Agreements

In the ordinary course of business, and as part of our hedging strategy, we enter into long-term sales arrangements for electric energy, capacity and ancillary services, as well as long-term purchase arrangements. For information regarding our long-term fuel supply contracts, purchase power and electric capacity contracts and commitments, electric energy and electric sale contracts and tolling arrangements, see notes 14(f), 14(k) and 14(l) to our consolidated financial statements. For information regarding our hedging strategy relating to such long-term commitments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Risks Related to Our Wholesale Energy Operations" in Item 7 of this Form 10-K/A.

Commercial Operations

Strategy. Our domestic commercial business optimizes our physical asset positions consisting of our power generation asset portfolio, pipeline storage positions and fuel positions and provides risk management services for our asset positions. We perform these functions through trading, marketing and hedging activities for power, fuels and other energy related commodities. With the downturn in the industry, the decline in market liquidity, and our liquidity capital constraints, the principal function of our commercial activities has shifted to optimizing our assets. Previous large volume activities primarily involving risk management to customers, gas marketing to third parties and trading of power and gas have been significantly reduced, and in some cases eliminated. As a result, we have reduced our trading workforce from 264 to 160 as of December 31, 2002, which

include traders, originators, dispatchers and schedulers. We have also reduced support staff, including technical staff, accountants and risk control personnel, from 645 to 587 as of December 31, 2002. In addition to these staffing reductions, several unfilled positions were eliminated. In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions.

Asset optimization and risk management. Our domestic commercial businesses complement our merchant power generation business by providing a full range of energy management services. These services focus on two core functions, optimizing our physical asset position and providing risk management services for our portfolio. To perform these functions, we trade, market and hedge electric energy, capacity and ancillary services, as well as manage the purchase and sale of fuels and emission allowances.

Asset optimization is maximizing the financial performance of an asset position. Our commercial groups optimize our assets by employing different products (e.g., on-peak power), geographic markets (e.g., buying from and selling into adjacent markets), fuel types (e.g., burning oil rather than natural gas at our fuel switching capable plants) and transaction terms (spot to multi-year term).

Risk management services focus on managing the performance risk and price risk (of both purchases and sales) inherent in the asset position. The ultimate purpose of this activity is to identify the risks and reduce the volatility they could cause in our financial performance. Our commercial groups assist our risk control personnel and management in the identification of these risks and execute the transactions necessary to achieve this goal. As an example of this, we generally seek to sell a portion of the capacity of our domestic facilities under fixed-price sale contracts (energy or capacity) or contracts to sell energy at a predetermined multiple of fuel prices. Generally, we also seek to hedge our fuel needs associated with our forward power sale obligations. These power sales and fuel purchases provide us with certainty as to a portion of our margins. With respect to performance risk, we also take into account plant operational constraints and operating risk in making these determinations.

Physical power and services from our assets portfolios are sold in real-time, hour-ahead, day-ahead, or multi-month or multi-year term markets. For purposes of supplying our generation, we purchase fuel from a variety of suppliers under daily, monthly and term, variable-load and base-load contracts that include either market-based or fixed pricing provisions. We use derivative instruments to execute these transactions. For additional information regarding our financial exposure to derivative instruments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Risks Related to Our Businesses Generally" in Item 7 of this Form 10-K/A and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K/A.

In addition, as part of our efforts to commercialize our asset portfolio and provide risk management services, we arrange for, schedule and balance the transportation of the natural gas from the supply receipt point to our plants. We generally obtain pipeline transportation to perform this function. Accordingly, we use a variety of transportation arrangements including short-term and long-term firm and interruptible agreements with intrastate and interstate pipelines. We also utilize brokered firm transportation agreements when dealing on the interstate pipeline system. In the normal course of business, it is common for us to hedge the risk of pipeline transportation expenses through "basis swap" transactions.

We also enter into various short-term and long-term firm and interruptible agreements for natural gas storage in order to offer peak delivery services to satisfy electric generating demands. Natural gas storage capacity allows us to better manage the unpredictable daily or seasonal imbalances between supply volumes and demand levels.

In support of our optimization and risk management effects, our power origination group, working closely with our other commercial groups, focuses on developing customized near-term products and long-term

contracts. These are designed and negotiated on a case-by-case basis to meet the specific energy requirements of our customers. The target customer group generally includes investor-owned utilities, municipalities, cooperatives and other companies that serve end users.

Risk management services to customers. In addition to optimizing our power asset portfolio, our trading and marketing businesses provide risk management services to a variety of customers, which include natural gas distribution companies, electric utilities, municipalities, cooperatives, power generators, marketers or other retail energy providers, aggregators and large volume industrial customers. Risk management services primarily focus on mitigating customers' commodity price exposure and providing firm delivery services. To provide these services to these customers, we utilize the same skills and physical and financial instruments used to optimize and manage the risks of our asset portfolio. See below for the discussion of our decision to exit proprietary trading in March 2003.

Proprietary Trading. Our commercial business obtains proprietary market knowledge and develops proprietary analysis through its efforts to manage our asset portfolio and provide risk management services to our customers. This enables our commercial groups to selectively take market positions, typically on a short-term basis, in power, fuel and other energy related commodities. Our commercial groups used derivative instruments to execute these transactions. In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions.

Risk Management Controls. For information regarding our risk management structure and policies relating to our trading and marketing operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Trading and Marketing Operations" in Item 7 of this Form 10-K/A and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K/A.

Regulation

Electricity. The FERC has exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce by "public utilities." Public utilities that are subject to the FERC's jurisdiction must file rates with the FERC applicable to their wholesale sales or transmission of electricity in interstate commerce. All of our generation subsidiaries sell electric energy, capacity and ancillary services at wholesale and are public utilities with the exception of two facilities in Texas that are classified as qualifying facilities and not regulated as public utilities. The FERC has authorized all of our generation subsidiaries to sell electricity and related services at wholesale at market-based rates. In its orders authorizing market-based rates, the FERC also has granted these subsidiaries waivers of many of the accounting, record keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules.

The FERC's orders accepting the market-based rate schedules filed by our subsidiaries or their predecessors, as is customary with such orders, reserve the right to revoke or limit our market-based rate authority if the FERC subsequently determines that any of our affiliates possess and exercise market power. If the FERC were to revoke or limit our market-based rate authority, we would have to file, and obtain the FERC's acceptance of, cost-based rate schedules for all or some of our sales. In addition, the loss of market-based rate authority could subject us to the accounting, record keeping and reporting requirements that the FERC imposes on public utilities with cost-based rate schedules.

The FERC has issued a notice of proposed rulemaking describing its intention to standardize electricity markets and eliminate continuing discrimination in transmission service, with a proposed implementation date of September 2004. The goal of SMD is to promote a more economically efficient market design that will lower delivered energy costs, maintain reliability, mitigate market power and increase customer choice options. SMD

proposes to eliminate discrimination in transmission service by requiring that all users of the grid take service pursuant to the same rates and terms and conditions of service, thus eliminating certain existing preferences enjoyed by some classes of customers. In addition, transmission-owning public utilities will be required to turn over the operation of their transmission systems to an independent transmission provider. SMD also seeks to establish day-ahead and real-time electric energy and ancillary service markets modeled after the energy markets that currently exist in the Northeast. Finally, SMD proposes to establish a capacity obligation on load serving entities and establishes nationwide price mitigation measures.

The FERC also continues to promote the formation of large RTOs and has issued numerous orders on the various RTO proposals. The FERC's goal is to promote the formation of a robust wholesale market for electricity. While RTO participation by public utilities is voluntary, the overwhelming majority of the FERC jurisdictional utilities have indicated that they will join the proposed RTO for their region. At this time there are approximately nine proposed RTOs covering the vast majority of the continental United States. In addition, large portions of the nation's transmission system are currently operated by an independent entity. The Midwest grid is operated by the MISO and the Northeast grid is operated by three separate independent entities: New England ISO, NYISO and PJM. The ERCOT ISO independently operates the Texas grid. MISO and PJM have received RTO status from the FERC.

Commercial Activities. Our domestic commercial operations are also subject to the FERC's jurisdiction. As a gas marketer, we make sales of natural gas in interstate commerce at wholesale pursuant to a blanket certificate issued by the FERC, but the FERC does not otherwise regulate the rates, terms or conditions of these gas sales.

Hydroelectric Facilities. Our hydroelectric generation facilities are subject to the FERC's exclusive authority to license non-federal hydroelectric projects located on navigable waterways and federal lands. These FERC licenses must be renewed periodically and can include conditions on operation of the project at issue.

SEC. A company engaged exclusively in the business of owning and/or operating facilities used for the generation of electric energy exclusively for sale at wholesale and selling electric energy at wholesale may be exempted from regulation under the PUHCA as an exempt wholesale generator. Our electric generation facilities have received determinations of exempt wholesale generator status from the FERC. If we lose our exempt wholesale generator status or qualifying facility status, we would have to restructure our organization or risk being subjected to further regulation by the SEC.

Competition

For a discussion of competitive factors affecting our wholesale energy segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Risks Related to Our Wholesale Energy Operations" in Item 7 of this Form 10-K/A.

European Energy

In Europe, we own and operate electric generation facilities and conduct trading and origination operations. In February 2003, we agreed to sell our European energy operations. We expect to consummate the sale during the summer of 2003. For additional information regarding the disposition of our European energy operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Risks Related to the Sale of Our European Energy Operations" and note 21(b) to our consolidated financial statements.

European Power Generation and Supply

Facilities. We own five electric power generation facilities with an aggregate net generating capacity of 3,496 MW, of which 3,231 MW are operational, located in the Netherlands. These facilities consist of approximately 39% of base-load, 15% of intermediate and 46% of peaking capacity. Our facilities are grouped in three clusters adjacent to the cities of Amsterdam, Utrecht and Velsen. In 2002, our generation facilities produced 14.2 million MWh, an amount that represented approximately 13% of the electricity production of the Netherlands. In addition to electricity, our generating stations sell heated water produced as a byproduct of the generation process for use in providing heating to the cities of Amsterdam, Nieuwegein, Utrecht and Purmerend and provide ancillary services, including grid support services, to transmission system owners.

In 2002, on a volumetric basis, approximately 50% of our European generation output was natural gas-fired, 30% was coal-fired, and 20% was blast furnace gas-fired. We purchase substantially all of our European gas fuel requirements under an annual gas purchase contract with N.V. Nederlandse Gasunie, the primary supplier and transporter of natural gas in the Netherlands. The purchase price and transportation costs for natural gas under these contracts are calculated on the basis of regulated tariffs. We obtain our European coal requirements through short to medium-term forward purchase contracts on the open market through a variety of suppliers and brokers. One of our European generation stations, which has a production capacity of 144 MW, uses blast furnace gas, an industrial waste gas generated by a steel plant adjacent to the generation station, as its fuel. Two of our other European generation plants have the flexibility to operate using blast furnace gas. We purchase substantially all blast furnace gas for the 144 MW facility from the adjacent steel plant under a medium-term and a long-term contract.

Market Framework. Our European energy segment produces, buys and sells electricity, gas and other energy-related commodities primarily in the Netherlands wholesale market. Our energy trading and origination operations and activities are concentrated in Northern Europe.

The primary customers in the Netherlands are electric distribution companies, large industrial consumers and energy trading companies. We sell electricity and other energy-related commodities primarily in the form of forward purchase contracts transacted in the over-the-counter markets, on various European energy exchanges and in negotiated transactions with individual counterparties. To a lesser extent, we also engage in transactions involving financial energy-related derivative products.

The most significant factor affecting the markets in which our European energy segment operates has been the deregulation of the Dutch and certain other European wholesale energy markets, including access on a non-discriminatory basis to high voltage transmission grid systems, the establishment of new energy exchanges and other events. Notwithstanding these factors, the scope and pace of the future liberalization of the European energy markets is uncertain. In some cases, fuel suppliers continue to operate in largely regulated markets not yet open to full competition.

There are significant differences in the United States and European markets. Among other things, European energy markets involve increased currency hedging requirements (the Euro and non-Euro currencies), and more complicated cross-border tax and transmission tariff systems than in the United States. In addition, European

energy markets are significantly less mature than United States energy markets in terms of liquidity, the scope and complexity of trading and marketing products, the use of standardized market-based trading contracts and other aspects.

In addition, there exist greater uncertainties in some European jurisdictions as to the enforceability of certain contract-based mechanisms to hedge risks, such as the enforceability of automatic terminations rights and rights of set-off upon bankruptcy, limitations on liquidated damages and the rules by which European courts construct contracts. In many civil law jurisdictions, courts reserve the right to interpret contracts based upon principles of good faith and fairness as opposed to a literal construction of the contract.

European Trading and Origination

Our European trading and origination operations are currently centered in the Netherlands, with an additional office in Germany. Our European trading and origination operations will focus on hedging and optimizing our generation assets in the Netherlands. During 2002, we traded electricity and fuel products in the Netherlands, Germany, Austria, the United Kingdom and the Scandinavian countries. As of December 31, 2002, we had entered into forward purchase and sale contracts, and associated hedging transactions, covering approximately 13.6 million MWh for delivery in 2003. In September 2002, we decided to substantially exit our proprietary trading activities in Europe and, in March 2003, we decided to exit our proprietary trading activities for the company as a whole.

Regulation

Prior to the deregulation of the Dutch wholesale market in 2001, our European energy segment sold its generating output to a national production pool and, in return, received a standardized remuneration based on generation output. The remuneration included fuel cost, return of and on capital and operation and maintenance expenses. In 2001, the wholesale energy market in the Netherlands was opened to competition. We continue to be subject to regulation by national and indirectly by European regulatory agencies and operate under regulations relating to the environment, labor, tax and other matters. For example, our operations are subject to the regulation of Dutch and European Community anti-trust authorities, that have extensive authority to investigate and prosecute violations by energy companies of anti-monopolistic and price-fixing regulations. In addition, our European operations must also comply with various national technical codes and other regulations establishing access to transmission systems. Many of our significant suppliers and customers in Europe are subject to continued regulation by various national energy regulatory bodies having the authority to establish tariffs for such suppliers and customers. The impact of regulations on these entities has an indirect impact on our European operations.

Competition

For a discussion of competitive factors affecting our European energy segment, see "Management's Discussion and Analysis of Financial Condition and Operations—Risk Factors—Risks Related to Our European Energy Operations" in Item 7 of this Form 10-K/A.

Other Operations

Our other operations business segment includes the following:

- our venture capital investment portfolio; and
- unallocated corporate costs.

We are currently managing our venture capital investment portfolio and do not have plans to expand this business. As of December 31, 2002, the net book value of these investments is $44 million. See note 2(o) to our consolidated financial statements.

Environmental Matters

General

We are subject to numerous federal, state and local requirements relating to the protection of the environment and the safety and health of personnel and the public. These requirements relate to a broad range of our activities, including the discharge of pollutants into air, water, and soil, the proper handling of solid, hazardous, and toxic materials and waste, noise, and safety and health standards applicable to the workplace. In order to comply with these requirements, we will spend substantial amounts from time to time to construct, modify and retrofit equipment, acquire air emission allowances for operation of our facilities, and to clean up or decommission disposal or fuel storage areas and other locations as necessary. We anticipate spending approximately $208 million from 2003 through 2007 for environmental compliance.

If we do not comply with environmental requirements that apply to our operations, regulatory agencies could seek to impose on us civil, administrative and/or criminal liabilities as well as seek to curtail our operations. Under some statutes, private parties could also seek to impose civil fines or liabilities for property damage, personal injury and possibly other costs.

Air Quality Matters

As part of the 1990 amendments to the Federal Clean Air Act, standards for the emission of nitrogen oxide, a product of the combustion process associated with power generation, are being developed or have been finalized. The standards require reduction of emissions from our power generating facilities in the United States.

The EPA has announced its determination to regulate hazardous air pollutants, including mercury, from coal-fired and oil-fired steam electric generating facilities under Section 112 of the Clean Air Act. The EPA plans to develop maximum achievable control technology standards for these types of generating facilities as well as for turbines, engines, and industrial boilers. The rulemaking for coal and oil-fired steam electric generating facilities must be completed by December 2004. Compliance with the rules will be required within three years thereafter. The maximum achievable control technology standards that will be applicable to the generating facilities cannot be predicted at this time and may adversely impact our operations. The rulemaking for turbines is expected to be complete in August 2003, and for engines and industrial boilers in early 2004. Based on the rules currently proposed, we do not anticipate a material adverse impact on our operations.

In 1998, the United States became a signatory to the United Nations Framework Convention on Climate Change or "Kyoto Protocol." The Kyoto Protocol calls for developed nations to reduce their emissions of greenhouse gases. Carbon dioxide, which is a major byproduct of the combustion of fossil fuel, is considered to be a greenhouse gas. If the United States Senate ultimately ratifies the Kyoto Protocol, any resulting limitations on power plant carbon dioxide emissions could have a material adverse impact on all fossil fuel fired facilities, including those belonging to us.

The EPA is conducting a nationwide investigation regarding the historical compliance of coal-fueled electric generating stations with various permitting requirements of the Clean Air Act. Specifically, the EPA and the United States Department of Justice have initiated formal enforcement actions and litigation against several other utility companies that operate these stations, alleging that these companies modified their facilities without proper pre-construction permit authority. Since June 1998, six of our coal-fired facilities have received requests for information related to work activities conducted at those sites, as have two of our recently acquired Orion Power facilities. The EPA has not filed an enforcement action or initiated litigation in connection with these facilities at this time. Nevertheless, any litigation, if pursued successfully by the EPA, could accelerate the timing of emission reductions currently contemplated for the facilities and result in the imposition of penalties.

In February 2001, the United States Supreme Court upheld previously adopted EPA ambient air quality standards for fine particulate matter and ozone. While attaining these new standards may ultimately require

expenditures for air quality control system upgrades for our facilities, regulations addressing affected sources and required controls are not expected until after 2005. Consequently, it is not possible to determine the impact on our operations at this time.

In February 2002, the White House announced its "Clear Skies Initiative." The proposal is aimed at long-term reductions of multiple pollutants produced from fossil fuel-fired power plants. Reductions averaging 70% are targeted for sulfur dioxide, nitrogen oxide and mercury. If approved by the United States Congress, this program would entail a market-based approach using emission allowances; compliance with emission limits would be phased in over a period from 2008 to 2018. The Clear Skies Initiative has the potential to revise or eliminate several of the programs discussed above, including the maximum achievable control technology standards, the coal-fired utility enforcement initiative and fine particulate controls. In addition, a voluntary program for reducing greenhouse gas emissions was proposed as an alternative to the Kyoto Protocol. Fossil fuel-fired power plants in the United States would be affected by the adoption of this program, or other legislation that may be enacted by the United States Congress addressing similar issues. Such programs would require compliance to be achieved by the installation of pollution controls, the purchase of emission allowances or curtailment of operations.

Units 1 and 2 of our Etiwanda Generating Station in California are currently subject to a regulatory permit variance that requires these units to be equipped with a selective catalytic reduction system or cease operation. We must decide by June 2003 to either surrender the permits for these units or commence the installation of a selective catalytic reduction system by the end of March 2004. Each unit has a rated capacity of 132 MW. Under the regulatory permitting rules regarding peaking generation facilities, our Etiwanda Unit 5 must have the "best available control technology" installed by the end of December 2003 or cease operation. We will evaluate the California capacity market in the second quarter of 2003 and determine whether to make the investment in the necessary environmental upgrades or retire the units.

Our facilities in the Netherlands were in compliance with applicable Dutch nitrogen oxide emission standards through the year 2002. New nitrogen oxide reduction targets have recently been adopted in the Netherlands, which will require a 50% reduction in nitrogen oxide emissions from stationary sources from 2000 levels by 2010. The reductions may be achieved through the installation of emission control equipment or through the participation in a planned market-based emission trading system. Regarding present emissions, we currently believe that our European facilities will not be required to install nitrogen oxide controls or purchase emission credits before January 2006. Projected emission control costs are estimated to be approximately $45 million, although this investment may be offset to some extent or delayed if a market-based trading program develops.

The European Union, of which the Netherlands is a member, adopted the Kyoto Protocol as the goal for greenhouse gas emission targets. We believe our European energy segment will meet its current portion of target reductions because of its use of "green fuels" and efficiency improvements to its facilities. Pilot testing of a number of fuels classified as "non-fossil" was initiated in 2002.

Water Quality Matters

As a result of litigation and technological improvements, state and federal efforts toward implementing the total maximum daily load provisions of the Clean Water Act have substantially increased in recent years. The establishment of total maximum daily loads to restore water bodies currently designated as impaired may result in more stringent discharge limitations for our facilities. Compliance with such limitations may require our facilities to install additional water treatment systems, modify operational practices or implement other wastewater control measures, the costs of which cannot be estimated at this time.

In April 2002, the EPA proposed rules under Section 316(b) of the Clean Water Act relating to the design and operation of cooling water intake structures. This proposal is the second of three current phases of

rulemaking dealing with Section 316(b) and generally would affect existing facilities that use significant quantities of cooling water. Under the amended court deadline, EPA is to issue final rules for these Phase II facilities by February 2004. While the requirements of the final rule cannot be predicted at this time, there are significant potential implications under the EPA proposal for our generating facilities.

A number of efforts are under way within the EPA to evaluate water quality criteria for parameters associated with the by-products of fossil fuel combustion. These parameters include arsenic, mercury and selenium. Significant changes in these criteria could impact station discharge limits and could require our facilities to install additional water treatment equipment. The impact on us as a result of these initiatives is unknown at this time.

Liability for Preexisting Conditions and Remediations

In connection with our acquisition of facilities, we, with a few exceptions, assumed liability for preexisting conditions, including some ongoing remediations. Funds for carrying out identified remediations have been included in our planning for future funding requirements, and we are not currently aware of any environmental condition at any of our facilities that we expect to have a material adverse effect on our financial position, results of operations or cash flows.

A prior owner of one of our Northeast facilities entered into a consent order agreement with the Pennsylvania Department of Environmental Protection to remediate a coal refuse pile on the property of the facility. Under the acquisition agreements between Sithe Energies, Inc. and GPU, Inc. relating to some of our Mid-Atlantic regional facilities, GPU has agreed to retain responsibility for up to $6 million of environmental liabilities associated with the coal refuse site at this facility. We will be responsible for any amounts in excess of $6 million. We expect our remaining obligation on the coal refuse site to be $1 million. In August 2000, we signed a modified consent order agreement that committed us to complete the remediation no later than November 2004. In connection with the acquisition of some of our Mid-Atlantic facilities, we have liabilities associated with six future ash disposal site closures. We expect to pay approximately $5 million over the next five years toward closure of these facilities.

Under the New Jersey Industrial Site Recovery Act, owners and operators of industrial properties are responsible for performing all necessary remediation at a facility prior to the closing of the facility and the termination of operations, or undertake actions that ensure that the property will be remediated after the closing of the facility and the termination of operations. In connection with the acquisition of our facilities from Sithe Energies, Inc., we have agreed to take responsibility for costs relating to the four New Jersey properties we purchased from Sithe Energies, Inc. We estimate that the costs to fulfill our obligations under the act will be approximately $8 million, which we expect to pay out through 2007. However, these remedial activities are still in the early stage. Following further investigation the scope of the necessary remedial work could increase, and we could, as a result, incur greater costs.

One of our Florida generation facilities discharges wastewater to percolation ponds, which in turn, percolate into the groundwater. Elevated levels of vanadium and sodium have been detected in groundwater monitoring wells. A noncompliance letter was received in 1999 from the Florida Department of Environmental Protection. In response to that letter, a study to evaluate the cause of the elevated constituents was undertaken and operational procedures were modified. At this time, if remediation is required, the cost, if any, is not anticipated to be material.

In connection with the acquisition of 70 hydro plants in northern and central New York, three gas/oil-fired plants in New York City, and one gas/oil-fired plant in central New York, Orion Power assumed the liability for the environmental remediation at several properties. Orion Power developed remediation plans for each of the subject properties and entered into consent orders with the New York State Department of Environmental Conservation at the three New York City sites and one hydro site for releases of petroleum and other substances

by the prior owners. The remaining portion of the liability we assumed for historical releases at all of these New York plants is approximately $8 million, which we expect to pay out through 2006. The consent order related to one New York City site also contained a provision to mitigate alleged impacts on fish populations. Activity on this issue was temporarily stayed pending the outcome of potential repowering opportunities. However, should repowering be considered inappropriate for this site, best technology available upgrades to the existing water intake system will have to be negotiated with the New York State Department of Environmental Conservation.

In connection with acquisition of Midwest assets by Orion Power, Orion Power became responsible for the liability associated with the closure of three ash disposal sites in Pennsylvania. The liability we assumed and recorded for these disposal sites as of December 31, 2002 was approximately $14 million, with $1 million to be paid over the next five years.

As a result of their age, many of our facilities contain significant amounts of asbestos insulation, other asbestos containing materials, as well as lead-based paint. Existing state and federal rules require the proper management and disposal of these potentially toxic materials. We have developed a management plan that includes proper maintenance of existing non-friable asbestos installations, and removal and abatement of asbestos containing materials where necessary because of maintenance, repairs, replacement or damage to the asbestos itself. We have planned for the proper management, abatement and disposal of asbestos and lead-based paint at our facilities in our financial planning.

Under CERCLA, owners and operators of facilities from which there has been a release or threatened release of hazardous substances, together with those who have transported or arranged for the disposal of those substances, are liable for the costs of responding to that release or threatened release, and the restoration of natural resources damaged by any such release. We are not aware of any liabilities under the act that would have a material adverse effect on our results of operations, financial position or cash flows.

Other European Environmental Matters

Under Dutch environmental laws, an environmental permit is required to be maintained for each generation facility. As is customary in Dutch practice, our European energy segment has, together with other industry participants, entered into various contractual agreements with the national government on specific environmental matters, including the reduction of the use of coal by partial switch from coal to fuels such as biomass, which are termed "non-fossil fuels" for purposes of compliance under the program. The environmental laws also address public safety. Our European energy segment holds all necessary authorizations and approvals for its current operations.

Nitrogen oxide reduction targets will require a 50% reduction in nitrogen oxide emissions of stationary sources from 2000 levels by 2010. The reductions may be achieved through the installation of emission control equipment or through the participation in a planned market-based emission trading system. Our European facilities are in compliance with current and applicable Dutch nitrogen oxide emission standards. Based on current factors, we have determined that our European facilities will not be required to install nitrogen oxide controls or purchase emission credits earlier than 2006.

Our European energy operations have budgeted to spend approximately $45 million in emission control and other environmental costs associated with our European energy segment for the period 2003 through 2007. In addition, we expect to spend approximately $8 million in asbestos and other environmental remediation programs during this period.

Employees

As of December 31, 2002, we had 6,002 full-time employees. Of these employees, 1,930 are covered by collective bargaining agreements. The collective bargaining agreements expire on various dates until May 14, 2007. The following table sets forth the number of our employees by business segment as of December 31, 2002:

Segment	Number
Retail energy	1,633
Wholesale energy	3,143
European energy	680
Other operations	546
Total	6,002

Executive Officers

Name	Age	Present Position
R. Steve Letbetter	55	Chairman and Chief Executive Officer
Stephen W. Naeve	55	President and Chief Operating Officer
Robert W. Harvey	47	Executive Vice President and Group President—Retail Business
Mark M. Jacobs	41	Executive Vice President and Chief Financial Officer
Hugh Rice Kelly	60	Senior Vice President, General Counsel and Corporate Secretary
Thomas C. Livengood	47	Vice President and Chief Accounting Officer

R. Steve Letbetter is our Chairman and Chief Executive Officer. Mr. Letbetter served as Chairman of CenterPoint from January 2000 until the Distribution and as President and Chief Executive Officer from June 1999 until the Distribution. Since 1978, he has served in various positions as an officer of CenterPoint and its corporate predecessors. Mr. Letbetter was a director of CenterPoint from 1995 until the Distribution. Mr. Letbetter resigned as Chairman, President and Chief Executive Officer of CenterPoint at the time of the Distribution.

Stephen W. Naeve is our President and Chief Operating Officer. He has served as Vice Chairman of CenterPoint from June 1999 until the Distribution and as Chief Financial Officer of CenterPoint from 1997 until the Distribution. From 1997 to 1999, Mr. Naeve held the position of Executive Vice President and Chief Financial Officer of CenterPoint. Since 1988, he served in various officer capacities with CenterPoint, including Vice President – Strategic Planning and Administration between 1993 and 1996. Mr. Naeve resigned as Vice Chairman of CenterPoint at the time of the Distribution.

Robert W. Harvey is our Executive Vice President and Group President—Retail Business. Mr. Harvey served as Vice Chairman of CenterPoint from June 1999 until the Distribution. From 1982 to 1999, Mr. Harvey was employed with the Houston office of McKinsey & Co., Inc. He was a director (senior partner) and was the leader of the firm's North American electric power and natural gas practice. Mr. Harvey resigned as Vice Chairman of CenterPoint at the time of the Distribution.

Mark M. Jacobs is our Executive Vice President and Chief Financial Officer. Mr. Jacobs served as Executive Vice President and Chief Financial Officer of CenterPoint from July 2002 until the Distribution. From 1989 to 2002, Mr. Jacobs was employed by Goldman, Sachs & Co. He was a Managing Director in the firm's Natural Resources Group. Mr. Jacobs resigned as Executive Vice President and Chief Financial Officer of CenterPoint at the time of the Distribution.

Hugh Rice Kelly is our Senior Vice President, General Counsel and Corporate Secretary. He served as Executive Vice President, General Counsel and Corporate Secretary of CenterPoint from 1997 until the Distribution. Between 1984 and 1997, he served as Senior Vice President, General Counsel and Corporate Secretary of CenterPoint. Mr. Kelly resigned as Executive Vice President, General Counsel and Corporate Secretary of CenterPoint at the time of the Distribution.

Thomas C. Livengood is our Vice President and Chief Accounting Officer. Prior to joining us in August 2002, he served as Executive Vice President and Chief Financial Officer of Carriage Services, Inc., a publicly traded consumer services company, since 1996. From 1991 to 1996, he served as Vice President and Chief Financial Officer of Tenneco Energy Company, a division of Tenneco, Inc.

ITEM 2. *Properties.*

Character of Ownership

Our corporate offices currently occupy approximately 500,000 square feet of leased office space in Houston, Texas, which lease expires in January 2004. During 2003, we expect to relocate our corporate offices. Upon relocation, our corporate offices will occupy approximately 520,000 square feet of leased office space in Houston, Texas. Our new lease expires in 2018, subject to two five-year renewal options.

In addition to our corporate office space, we lease or own various real property and facilities relating to our generation assets and development activities. Our principal generation facilities are generally described under "Our Business—Wholesale Energy" and "Our Business—European Energy" in Item 1 of this Form 10-K/A. We believe we have satisfactory title to our facilities in accordance with standards generally accepted in the electric power industry, subject to exceptions, which, in our opinion, would not have a material adverse effect on the use or value of the facilities.

Retail Energy

For information regarding the properties of our retail energy segment, see "Our Business—Retail Energy" in Item 1 of this Form 10-K/A.

Wholesale Energy

For information regarding the properties of our wholesale energy segment, see "Our Business—Wholesale Energy" in Item 1 of this Form 10-K/A.

European Energy

For information regarding the properties of our European energy segment, see "Our Business—European Energy" in Item 1 of this Form 10-K/A.

Other Operations

For information regarding the properties of our other operations segment, see "Our Business—Other Operations" in Item 1 of this Form 10-K/A.

ITEM 3. *Legal Proceedings.*

For a description of certain legal and regulatory proceedings affecting us, see note 14 to our consolidated financial statements.

ITEM 4. *Submission of Matters to a Vote of Security Holders.*

No matters were submitted to a vote of our security holders during the fourth quarter of the fiscal year ended December 31, 2002.

PART II

ITEM 5. *Market for Our Common Equity and Related Stockholder Matters.*

As of March 5, 2003, our common stock was held of record by approximately 63,215 stockholders of record and approximately 132,892 beneficial owners. Our common stock is listed on the New York Stock Exchange and is traded under the symbol "RRI." The following table sets forth the high and low sales prices of our common stock on the New York Stock Exchange composite tape during the periods indicated, as reported by *Bloomberg*:

	Market Price High	Market Price Low
2001		
Second Quarter (from May 1 through June 30)	$37.50	$23.65
Third Quarter	$28.60	$14.45
Fourth Quarter	$19.85	$13.20
2002		
First Quarter	$17.45	$ 9.50
Second Quarter	$17.16	$ 7.28
Third Quarter	$ 8.95	$ 1.66
Fourth Quarter	$ 3.23	$ 0.99

The closing market price of our common stock on December 31, 2002 was $3.20 per share.

We have not paid or declared any dividends since our formation and currently intend to retain earnings for use in our business. Any future dividends will be subject to determination based upon our results of operations and financial condition, our future business prospects, any applicable contractual restrictions and other factors that our board of directors considers relevant. For a discussion of our restrictions on payment of dividends, see note 21(a) to our consolidated financial statements.

During 2001, we purchased 11 million shares of our common stock at an average price of $17.22 per share, or an aggregate purchase price of $189 million. For additional information, see note 10(b) to our consolidated financial statements.

On December 6, 2001, our board of directors authorized us to purchase up to an additional 10 million shares of our common stock through June 2003. For additional information, see note 10(b) to our consolidated financial statements.

ITEM 6. *Selected Financial Data.*

The following tables present our selected consolidated financial data for 1998 through 2002. The financial data for 1998, 1999 and 2000 are derived from the consolidated historical financial statements of CenterPoint. The data set forth below should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations," our historical consolidated financial statements and the notes to those statements included in this Form 10-K/A. The historical financial information may not be indicative of our future performance and does not reflect what our financial position and results of operations would have been had we operated as a separate, stand-alone entity during the periods presented.

	Year Ended December 31,				
	1998 (1)(4)	1999 (1)(4)	2000 (1)(4)(5)	2001 (2)(4)(5)	2002 (1)(3)(4)
	(In millions, except per share amount)				
Income Statement Data:					
Revenues	$277	$657	$3,275	$6,130	$11,248
Trading margins	33	88	200	369	310
Total	310	745	3,475	6,499	11,558
Expenses:					
Fuel and cost of gas sold	102	317	1,171	1,976	1,443
Purchased power	13	149	926	2,509	7,381
Accrual for payment to CenterPoint	—	—	—	—	128
Operation and maintenance	65	136	422	494	903
General, administrative and development	78	100	304	503	665
European energy goodwill impairment	—	—	—	—	482
Depreciation and amortization	15	29	194	247	436
Total	273	731	3,017	5,729	11,438
Operating income	37	14	458	770	120
Other income (expense):					
Gains (losses) from investments	—	16	(17)	22	(24)
(Loss) income of equity investments of unconsolidated subsidiaries	(1)	21	43	57	23
Gain on sale of development project	—	—	18	—	—
Other, net	1	(6)	6	9	33
Interest expense	(2)	(9)	(42)	(63)	(304)
Interest income	1	—	18	27	35
Interest income (expense)—affiliated companies, net	2	(10)	(173)	12	5
Total other income (expense)	1	12	(147)	64	(232)
Income (loss) before income taxes, cumulative effect of accounting change and extraordinary item	38	26	311	834	(112)
Income tax expense	(17)	(2)	(95)	(274)	(214)
Income (loss) before cumulative effect of accounting change and extraordinary item	21	24	216	560	(326)
Cumulative effect of accounting change, net of tax	—	—	—	3	(234)
Extraordinary item, net of tax	—	—	7	—	—
Net income (loss)	$ 21	$ 24	$ 223	$ 563	$ (560)
Basic and Diluted Earnings per Share:					
Income (loss) before cumulative effect of accounting change				$ 2.02	$ (1.12)
Cumulative effect of accounting change, net of tax				0.01	(0.81)
Net income (loss)				$ 2.03	$ (1.93)

	Year Ended December 31,				
	1998(1)	1999(1)	2000(1)(5)	2001(2)(5)	2002(1)(3)
	(in millions, except operating data)				
Statement of Cash Flow Data:					
Cash flows from operating activities	$ (2)	$ 35	$ 328	$ (127)	$ 611
Cash flows from investing activities	(365)	(1,406)	(3,013)	(838)	(3,486)
Cash flows from financing activities	379	1,408	2,721	1,000	3,981
Other Operating Data:					
Trading and marketing activity (6):					
Natural gas (Bcf) (7)	1,115	1,481	2,273	3,265	3,449
Power sales (thousand MWh) (7)	61,195	128,266	127,062	248,139	378,085
Power generation activity:					
Wholesale power sales (thousand MWh) (7)	2,973	10,204	39,300	63,298	129,358
European power sales (thousand MWh)	—	2,846	11,606	16,344	17,794
Retail power sales (GWh)					58,458
Net power generation capacity (MW)	3,800	7,945	12,707	14,585	23,384

	December 31,				
	1998	1999	2000(5)	2001(5)	2002
	(in millions)				
Balance Sheet Data:					
Property, plant and equipment, net	$ 270	$ 2,407	$ 4,049	$ 4,559	$ 8,941
Total assets	1,409	5,624	13,475	11,719	17,636
Short-term borrowings	—	170	126	297	1,299
Long-term debt to third parties, including current maturities		460	892	892	6,196
Accounts and notes (payable) receivable—affiliated companies, net	(17)	(1,333)	(1,969)	445	—
Stockholders' equity	652	741	2,332	5,984	5,653

(1) Our results of operations include the results of the following acquisitions, all of which were accounted for using the purchase method of accounting, from their respective acquisition dates: the five generating facilities in California substantially acquired in April 1998, a generating facility in Florida and REPGB both acquired in October 1999, the REMA acquisition that occurred in May 2000 and the Orion Power acquisition that occurred in February 2002. See note 5 to our consolidated financial statements for further information about the acquisitions occurring in 2000 and 2002.

(2) Effective January 1, 2001, we adopted SFAS No. 133 which established accounting and reporting standards for derivative instruments. See note 7 to our consolidated financial statements for further information regarding the impact of the adoption of SFAS No. 133.

(3) During the third quarter of 2002, we completed the transitional impairment test for the adoption of SFAS No. 142 on our consolidated financial statements, including the review of goodwill for impairment as of January 1, 2002. Based on this impairment test, we recorded an impairment of our European energy segment's goodwill of $234 million, net of tax, as a cumulative effect of accounting change. Based on our annual impairment test (November 1, 2002), we recognized an impairment of the remaining amount of our European energy segment's net goodwill of $482 million in the fourth quarter of 2002. See note 6 to our consolidated financial statements for further discussion.

(4) Beginning with the quarter ended September 30, 2002, we now report all energy trading and marketing activities on a net basis in the statements of consolidated operations. Comparative financial statements for prior periods have been reclassified to conform to this presentation. See note 2(t) to our consolidated financial statements for further discussion.

(5) As described in note 1 to our consolidated financial statements, our consolidated financial statements for 2000 and 2001 have been restated from amounts previously reported. The restatement had no impact on previously reported consolidated cash flows.

(6) Excludes financial transactions.

(7) Includes physical contracts not delivered.

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

Restatement

Subsequent to the issuance of our financial statements as of and for the year ended December 31, 2001, we identified four natural gas financial swap transactions that should not have been recorded in our records. We have concluded, based on the offsetting nature of the transactions and manner in which the transactions were documented, that none of the transactions should have been given accounting recognition. We previously accounted for these transactions in our financial statements as a reduction in revenues in December 2000 and an increase in revenues in January 2001, with the effect of decreasing net income in the fourth quarter of 2000 and increasing net income in the first quarter of 2001, in each case by $20.0 million pre-tax ($12.7 million after-tax) and the effect of increasing basic and diluted earnings per share by $0.05 in the first quarter of 2001. There were no cash flows associated with the transactions.

Also, subsequent to the issuance of our financial statements for 2001 and for the first three quarters of 2002, we determined that we had incorrectly calculated the amount of hedge ineffectiveness for 2001 and the first three quarters of 2002 for hedging instruments entered into prior to the adoption of SFAS No. 133. These hedging instruments included long-term forward contracts for the sale of power in the California market through December 2006. The amount of hedge ineffectiveness for these forward contracts was calculated using the trade date. However, the proper date for the hedge ineffectiveness calculation is hedge inception, which for these contracts was deemed to be January 1, 2001, concurrent with the adoption of SFAS No. 133. These errors in accounting for hedge ineffectiveness resulted in an understatement of revenues of $28.7 million ($18.6 million after-tax) and earnings per share of $0.07 in 2001.

The consolidated financial statements for 2000 and 2001 have been restated from amounts previously reported to remove the effects of the four natural gas swap transactions from 2000 and 2001 and to correctly account for the amount of hedge ineffectiveness in 2001. The following discussion and analysis has been modified for the restatement. A summary of the principal effects of the restatement on our consolidated financial statements for 2000 and 2001 are set forth in note 1 to our consolidated financial statements.

Overview

We provide electricity and energy services with a focus on the competitive retail and wholesale segments of the electric power industry in the United States. We have built a portfolio of electric power generation facilities, through a combination of acquisitions and development that are not subject to traditional cost-based regulation; therefore, we can generally sell electricity at prices determined by the market, subject to regulatory limitations. We trade and market electricity, natural gas, natural gas transportation capacity and other energy-related commodities. We also optimize our physical assets and provide risk management services for our asset portfolio. In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions.

In this section we discuss our results of operations on a consolidated basis and on a segment basis for each of our financial reporting segments. We also discuss liquidity and capital resources. Our segments include retail energy, wholesale energy, European energy and other operations. For segment reporting information, see note 20 to our consolidated financial statements.

In February 2002, we acquired all of the outstanding shares of common stock of Orion Power for an aggregate purchase price of $2.9 billion and we assumed $2.4 billion in debt obligations. For additional information regarding our acquisition of Orion Power, see note 5(a) to our consolidated financial statements.

In May 2001, we offered 59.8 million shares of our common stock to the public at an IPO price of $30 per share and received net proceeds of $1.7 billion. Pursuant to a master separation agreement between CenterPoint and Reliant Resources, we used $147 million of the net proceeds to repay certain indebtedness owed to CenterPoint. On September 30, 2002, the Distribution was completed. The Distribution completed our separation from CenterPoint. In connection with our anticipated separation from CenterPoint, CenterPoint contributed to us effective December 31, 2000, our wholesale, retail and other operations. Through December 31, 2000, CenterPoint and its direct and indirect subsidiaries conducted these operations. For additional information regarding this contribution from CenterPoint and agreements with CenterPoint entered into as a part of CenterPoint's business separation plan, see notes 3 and 4 to our consolidated financial statements.

The financial information for the year ended December 31, 2000 discussed in this Item 7 is derived from the consolidated historical financial statements of CenterPoint, which include the results of operations for all of CenterPoint's businesses, including those businesses which we do not own. Therefore, in order to prepare our financial statements for 2000, contained in this Form 10-K/A and discussed in this Item 7, we carved out the results of operations of the businesses that we own from CenterPoint's consolidated historical financial statements. Accordingly, the results of operations discussed in this Item 7 for such years include only revenues and costs directly attributable to the businesses we own and operate. Some of these costs are for facilities and services provided by CenterPoint and for which our operations have historically been charged based on usage or other allocation factors. We believe these allocations are reasonable, but they are not necessarily indicative of the expenses that would have resulted if we had actually operated independently of CenterPoint. We may experience changes in our cost structure, funding and operations as a result of our separation from CenterPoint, including increased costs associated with reduced economies of scale, and increased costs associated with being a publicly traded, independent company. We cannot predict, with any certainty, the actual amount of increased costs we may incur, if any.

During 2002, the following factors, among others, negatively impacted our business:

- weaker pricing for electric energy, capacity and ancillary services;
- narrowing of the spark spread in most regions of the United States in which we operate generation facilities;
- market contraction;
- reduced liquidity in the United States and Northwest Europe power markets; and
- downgrades in our credit ratings to below investment grade by each of the major rating agencies.

We expect these weak conditions to persist through 2003. However, in the next few years we anticipate that supply surpluses will begin to tighten, regulatory intervention will become more balanced and as a result prices will improve for electric energy, capacity and ancillary services. This view is consistent with our fundamental belief that long run market prices must reach levels sufficient to support an adequate rate of return on the construction of new generation. However, if in the long term the current weak environment persists, we could have significant impairments of our property, plant and equipment and goodwill which, in turn, could have a material adverse effect on our results of operations.

In addition, our operations are impacted by changes in commodities other than electric energy, in particular by changes in natural gas prices. During the first quarter of 2003, there was significant volatility in the natural gas market. As a result, we realized a trading loss related to certain of our natural gas trading positions of approximately $80 million pre-tax in the first quarter of 2003. Our wholesale energy segment's results from its unhedged coal-fired generation capacity in the Mid-Atlantic region are impacted by natural gas prices as electric energy prices are affected by changes in natural gas prices and coal prices are substantially uncorrelated to gas prices. In addition, we can optimize the fuel costs of our dual fuel generating assets by running the most cost-efficient fuel. Our retail energy segment can also be impacted by changes in natural gas prices. The PUCT's regulations allow an affiliated retail electric provider to adjust the wholesale energy supply cost component or

"fuel factor," included in its price to beat based on a percentage change in the forward price of natural gas. An affiliated retail electric provider may request that its price to beat fuel factor be adjusted twice a year. We cannot estimate with any certainty the magnitude and timing of future adjustments required, if any, or the impact of such adjustments on our headroom. For additional information regarding adjustments to our price to beat fuel factor, see "Management's Discussion and Analysis of Financial Condition and Results of Operations —EBIT by Business Segment." To the extent there are future changes in natural gas prices, our results of operations, financial condition and cash flows will be affected.

In February 2003, we signed a share purchase agreement to sell our European energy operations to Nuon, a Netherlands-based electricity distributor. We recognized a loss of approximately $0.4 billion in the first quarter of 2003 in connection with the anticipated sale. We do not anticipate that there will be a Dutch or United States income tax benefit realized by us as a result of this loss. We will recognize contingent payments, if any, in earnings upon receipt. In the first quarter of 2003, we began to report the results of our European energy operations as discontinued operations in accordance with SFAS No. 144. For further discussion of the sale, see note 21(b) to our consolidated financial statements.

Consolidated Results of Operations

The following table provides summary data regarding our consolidated results of operations for 2000, 2001 and 2002:

	Year Ended December 31,		
	2000	2001	2002
	(In millions)		
Operating revenues (1)	$3,475	$6,499	$11,558
Operating expenses	3,017	5,729	11,438
Operating income	458	770	120
Other (expense) income, net	(147)	64	(232)
Income tax expense	95	274	214
Income (loss) before cumulative effect of accounting change and extraordinary gain	216	560	(326)
Cumulative effect of accounting change, net of tax	—	3	(234)
Extraordinary gain	7	—	—
Net income (loss)	$ 223	$ 563	$ (560)

(1) Operating revenues reflect trading activities on a net basis as described in note 2(d) to our consolidated financial statements.

2002 Compared to 2001

Net Income. We reported a $(560) million consolidated net loss, or $(1.93) loss per share, for 2002 compared to $563 million in consolidated net income, or $2.03 earnings per diluted share, for 2001. The 2001 results included a cumulative effect of accounting change of $3 million, net of tax, related to the adoption of SFAS No. 133. For additional discussion of the adoption of SFAS No. 133, see note 7 to our consolidated financial statements. The 2002 results included a cumulative effect of accounting change of $(234) million, net of tax, related to the adoption of SFAS No. 142. For additional discussion of the adoption of SFAS No. 142, see note 6 to our consolidated financial statements. Our consolidated (loss) income, before cumulative effect of accounting change, was $(326) million for 2002 compared to $560 million for 2001. The $886 million decrease was primarily due to the following:

- a $848 million decrease in EBIT from our wholesale energy segment;
- a $469 million decrease in EBIT from our European energy segment which includes a $482 million goodwill impairment recorded in the fourth quarter of 2002;

- a $240 million increase in net interest expense, including interest related to advances to affiliated companies;

- a total of $32 million pre-tax impairment losses ($30 million after-tax) on venture capital investments in 2002 coupled with a $14 million decrease in gains on investments from $23 million in 2001 to $9 million in 2002 of our other operations segment; and

- changes in our effective tax rate, which are further discussed below.

The above items were partially offset by:

- a $533 million increase in EBIT from our retail energy segment;

- $54 million in pre-tax disposal charges and impairments of goodwill and fixed assets related to exiting our communications business recorded in 2001 by our other operations segment; and

- a $53 million decrease in charges incurred relating to the redesign and settlement of some of CenterPoint's benefit plans related to our separation from CenterPoint.

EBIT. For an explanation of changes in EBIT, see "—EBIT by Business Segment."

Interest Expense. We incurred $264 million of net interest expense in 2002 compared to $24 million for 2001. The $240 million increase in net interest expense in 2002 as compared to 2001 resulted primarily from a $241 million increase in interest expense to third parties, net of interest expense capitalized on projects, primarily as a result of higher levels of borrowings related to the acquisition of Orion Power in February 2002 and to a lesser extent, an increase in interest rates due to downgrades in our credit ratings. The decrease of $7 million in interest income on net advances to affiliated companies in 2002 as compared to 2001 resulted primarily from decreased net advances of excess cash to a subsidiary of CenterPoint during 2002. This was partially offset by interest expense incurred prior to the conversion into equity of $1.7 billion of debt owed to CenterPoint and its subsidiaries in connection with the completion of our IPO in 2001.

Income Tax Expense. Our deferred income taxes are calculated using the liability method of accounting, which measures deferred income taxes for all significant income tax temporary differences. Prior to the Distribution, we calculated our income tax provision on a separate return basis under a tax sharing agreement with CenterPoint. Our current federal and some state income taxes were payable to or receivable from CenterPoint prior to the Distribution. During 2001, our effective tax rate was 32.9%. During 2002, our effective tax rate was not meaningful as we had a $112 million pre-tax loss and $214 million in income tax expense. Our reconciling items from the federal statutory rate of 35% to the effective tax rate totaled $253 million and $18 million for 2002 and 2001, respectively. The change in the reconciling items from 2002 to 2001 primarily related to the following:

- a $482 million goodwill impairment related to our European energy segment which is not deductible for tax purposes;

- a $45 million United States federal tax provision for future cash distributions from our equity investment in NEA in which our European energy segment holds a 22.5% economic interest (see note 13 to our consolidated financial statements);

- an increase in valuation allowances primarily due to losses incurred by our European energy trading and origination operations in 2002 and the impairment of certain venture capital investments in 2002;

- an increase in state income taxes primarily resulting from our retail energy segment's operations in 2002 and the impact of the Orion Power acquisition in February 2002, partially offset by New York state income tax credits; and

- the end of the Dutch tax holiday in January 2002 related to the Dutch electricity sector.

The above items were partially offset by the impact of the cessation of goodwill amortization in 2002 (see note 6 to our consolidated financial statements).

In 2001, the earnings of REPGB were subject to a zero percent Dutch corporate income tax rate as a result of the tax holiday related to the Dutch electricity industry. In 2002, European energy's earnings in the Netherlands are subject to the standard Dutch corporate income tax rate, which is currently 34.5%.

Subsequent to the Distribution, we ceased being a member of the CenterPoint consolidated tax group. This separation could have future income tax implications for us. Our separation from the CenterPoint consolidated tax group changed our overall future income tax posture. As a result, we could be limited in our future ability to effectively use future tax attributes. We have agreed with CenterPoint that we may carry back net operating losses we generate in our tax years after deconsolidation to tax years when we were part of the CenterPoint consolidated tax group subject to CenterPoint's consent and any existing statutory carryback limitations. CenterPoint has agreed not to unreasonably withhold such consent.

2001 Compared to 2000

Net Income. We reported $563 million of consolidated net income, or $2.03 earnings per share, for 2001 compared to $223 million for 2000. The 2001 results included a cumulative effect of accounting change of $3 million, net of tax, related to the adoption of SFAS No. 133. The 2000 results included an extraordinary gain of $7 million related to the early extinguishment of $272 million of long-term debt. For additional discussion of the extraordinary gain, see note 9(c) to our consolidated financial statements. Our consolidated income before cumulative effect of accounting change and extraordinary item was $560 million for 2001 compared to $216 million for 2000. The increase of $344 million was primarily due to the following:

- a $344 million increase in EBIT from our wholesale energy segment;
- a $173 million decrease in net interest expense primarily related to debt with affiliated companies;
- a $57 million decrease in loss before interest and taxes from our retail energy segment;
- a $27 million pre-tax impairment loss on marketable equity securities classified as "available-for-sale" in 2000 coupled with an increase in gains on investments from $1 million in 2000 to $23 million in 2001 of our other operations segment; and
- a $24 million increase in EBIT from our European energy segment;

The above items were partially offset by the following:

- a $100 million pre-tax, non-cash charge relating to the redesign of some of CenterPoint's benefit plans in anticipation of our separation from CenterPoint;
- $54 million in pre-tax disposal charges and impairments of goodwill and fixed assets related to the exiting of our communications business in 2001; and
- an increase in our effective tax rate, as further discussed below.

EBIT. For an explanation of changes in EBIT, see "—EBIT by Business Segment."

Interest Expense. We incurred $24 million of net interest expense during 2001 compared to $197 million in 2000. The $173 million decrease in net interest expense in 2001 as compared to 2000 resulted primarily from the following:

- the conversion into equity of $1.7 billion of debt owed to CenterPoint and its subsidiaries in connection with the completion of our IPO in May 2001;

- the $1.0 billion repayment in August 2000 of debt owed to CenterPoint related to our acquisition of REMA, which is included in our Mid-Atlantic region operations, from proceeds received from the generating facilities' sale-leaseback transactions; and
- the advancing of excess cash primarily resulting from our IPO to a subsidiary of CenterPoint.

These decreases were slightly offset by a $21 million increase in interest expense to third parties, net of interest expense capitalized on projects, primarily as a result of higher levels of borrowings related to construction of power generation facilities and credit facility fees.

Income Tax Expense. During 2001 and 2000, our effective tax rate was 32.9% and 30.8%, respectively. Our reconciling items from the federal statutory tax rate to the effective tax rate totaled $18 million and $13 million for 2001 and 2000, respectively. These items primarily related to a tax holiday for income earned by REPGB and were partially offset by nondeductible goodwill, state income taxes and valuation allowances.

EBIT by Business Segment

The following tables present operating income (loss) and EBIT for each of our business segments for the years ended December 31, 2000, 2001 and 2002. EBIT is the primary measure we use to evaluate the performance of our business segments. We believe EBIT is a good indicator of each business segment's operating performance. EBIT is not defined under GAAP, should not be considered in isolation or as a substitute for a measure of performance prepared in accordance with GAAP and is not indicative of operating income from operations as determined under GAAP. Additionally, our computation of EBIT may not be comparable to other similarly titled measures computed by other companies, because all companies do not calculate it in the same fashion. For a reconciliation of our operating income (loss) to EBIT and EBIT to net income (loss), see note 20 to our consolidated financial statements. For a reconciliation of our operating income (loss) to EBIT by segment, see the related discussion by segment below.

The following table sets forth our operating income (loss) by segment for 2000, 2001 and 2002:

	Year Ended December 31,		
	2000	2001	2002
	(in millions)		
Retail energy	$ (70)	$ (13)	$ 524
Wholesale energy	505	907	24
European energy	84	56	(371)
Other operations	(61)	(180)	(57)
Total	$458	$ 770	$ 120

The following table sets forth our EBIT by segment for 2000, 2001, 2002:

	Year Ended December 31,		
	2000	2001	2002
	(in millions)		
Retail energy	$ (70)	$ (13)	$ 520
Wholesale energy	572	916	68
European energy	89	113	(356)
Other operations	(83)	(158)	(80)
Total	$508	$ 858	$ 152

Retail Energy

Our retail energy segment provides electricity products and services to end-use customers, ranging from residential and small commercial customers to large commercial, industrial and institutional customers. Our retail energy segment acquires and manages the electric energy, capacity and ancillary services associated with supplying these retail customers. We began serving approximately 1.7 million electric customers in the Houston metropolitan area when the Texas market opened to full competition in January 2002. At the end of 2002, our customer count remained substantially the same; however, we lost market share in the Houston market and added customers in other areas of Texas. During 2002, our retail energy segments' operational efforts were largely focused on the extensive efforts necessary to transition customers from the electric utilities to the affiliated retail electric providers. We participated in preliminary marketing programs in mid-2001 to gain customers outside of the Houston metropolitan area, primarily in the Dallas/Fort Worth area. In addition, this segment manages the procurement of electricity supply for these customers. For further information regarding our contract to purchase supply from Texas Genco, see note 4(b) to our consolidated financial statements.

We record our electricity sales and services to residential, small commercial and large commercial, industrial and institutional customers who have not signed a contract under the accrual method and these revenues generally are recognized upon delivery. Contracted electricity sales to large commercial, industrial and institutional customers were accounted for under the mark-to-market method of accounting and presented net for contracts entered into prior to October 25, 2002. Effective January 1, 2003, we will no longer mark to market in earnings a substantial portion of these contracts and the related energy supply contracts. Contracted sales by our retail energy segment to large commercial, industrial and institutional customers and the related supply contracts entered into after October 25, 2002, will, for the most part, no longer be marked to market through earnings, in connection with the implementation of EITF No. 02-03 which rescinded EITF No. 98-10. The earnings from these contracts will generally be recognized as the related volumes are delivered. Historically, these energy contracts were recorded at fair value in trading margins upon contract execution. The net changes in their market values were recognized in the statement of consolidated operations in trading margins in the period of the change.

Electricity sales and services related to retail customers not billed are recognized based upon estimated electricity and services delivered. At December 31, 2002, the amount not billed is $216 million, including approximately $25 million related to delayed billings. Problems or delays in the flow of information between the ERCOT ISO, the transmission and distribution utility and the retail electric providers and operational problems with our new systems and processes could impact our ability to accurately estimate the amount not billed at December 31, 2002. In addition, for certain customers that did not receive an electric bill, we cannot bill or collect for a period beyond six months from when an error is discovered except in the instance of theft. As of December 31, 2002, the amount of electricity that could not be billed did not have a significant impact on our results of operations or cash flows.

We depend on the transmission and distribution utilities to read our customers' electric meters. We are required to rely on the transmission and distribution utility or, in some cases, the ERCOT ISO, to provide us with our customers' information regarding electricity usage, such as historical usage patterns, and we may be limited in our ability to confirm the accuracy of the information. The provision of inaccurate information or delayed provision of such information by the transmission and distribution utilities or the ERCOT ISO could have a material negative impact on our business, results of operations and cash flows.

We record our transmission and distribution charges using the same method detailed above for our electricity sales and services to retail customers. At December 31, 2002, the transmission and distribution charges not billed by the transmission and distribution utilities to us totaled $59 million. Delays or inaccurate billings from the transmission and distribution utilities could impact our ability to accurately reflect our transmission and distribution costs.

The ERCOT ISO is responsible for maintaining reliable operations of the electric power supply system in the ERCOT Region. The ERCOT ISO is also responsible for handling scheduling and settlement for all

electricity volumes in the Texas deregulated electricity market. As part of settlement, the ERCOT ISO communicates the actual volumes compared to the scheduled volumes. The ERCOT ISO calculates an additional charge or credit based on the difference between the actual and scheduled volumes, based on a market-clearing price. Settlement charges also include allocated costs such as unaccounted for energy. Preliminary settlement information is due from the ERCOT ISO within two months after electricity is delivered. Final settlement information is due from the ERCOT ISO within twelve months after electricity is delivered. As a result, we record our estimated supply costs using estimated supply volumes and adjust those costs upon receipt of settlement and consumption information. The ERCOT ISO settlement process was delayed due to operational problems between the ERCOT ISO, the transmission and distribution utilities and the retail electric providers. During the third quarter of 2002, the ERCOT ISO began issuing final settlements for the pilot time period of July 31, 2001 to December 31, 2001. The final settlements have been suspended until a market synchronization of all customers between the market participants takes place. The market synchronization will validate which retail electric provider served each customer, for each day, beginning as of January 1, 2002, which was the date the market opened to retail competition. This information will be confirmed by the ERCOT ISO, the retail electric providers and the transmission and distribution utilities. Once this market synchronization is complete, the ERCOT ISO will resume the final settlement process beginning with January 1, 2002. The delay in the ERCOT ISO settlement process could impact our ability to accurately reflect our energy supply costs.

We believe that the estimates and assumptions utilized for the above items to recognize revenues and supply costs, as applicable, are reasonable and represent our best estimates. However, actual results could differ from those estimates.

We also provided billing, customer service, credit and collection and remittance services to CenterPoint's regulated electric utility and two of its natural gas distribution divisions. The service agreement governing these services terminated on December 31, 2001. We charged the regulated electric and natural gas utilities for these services at cost.

We expect to continue to lose residential and small commercial market share in the Houston market during 2003, as competition increases. We expect to gain residential and small commercial market share in other areas of the state. The efforts to seek such gains will require us to increase our spending for marketing and advertising. We expect to continue to increase our market share of large commercial, industrial and institutional customers in the ERCOT Region. We also expect to see a reduction in margin attributable to certain large commercial, industrial and institutional customers who have not signed contracts, as these customers sign contracts with us or other competitors at more favorable rates. When the market opened to competition, large commercial, industrial and institutional customers who did not sign contracts were assigned to be served by the affiliated residential electric provider at a designated rate. This designated rate may be higher than the rate available in the competitive market.

During 2002, we filed two requests with the PUCT to increase the price to beat fuel factor for residential and small commercial customers based on increases in the price of natural gas. The August 2002 increase was based on an increase in the natural gas price from $3.11 per MMbtu to $3.73 per MMbtu. The December 2002 increase was based on a natural gas price of $4.02 per MMbtu. In March 2003, the PUCT approved our request to increase the price to beat fuel factor for residential and small commercial customers based on a 23.4% increase in the price of natural gas from our previous increase in December 2002. The approved increase was based on natural gas prices of $4.956 per MMbtu. The increase represents an 8.2% increase in the total bill of a residential customer using, on average, 12,000 KWh per year. For additional information regarding the price to beat fuel factor, see notes 14(e) and 21(d) to our consolidated financial statements.

For additional information regarding factors that may affect the future results of operations of our retail energy segment, see "—Risk Factors—Risk Related to Our Retail Energy Operations."

The following table provides summary data, including EBIT, of our retail energy segment for 2000, 2001 and 2002:

	Retail Energy Segment		
	Year Ended December 31,		
	2000	2001	2002
	(in millions, except operating data)		
Retail electricity sales and services revenues	$ 64	$114	$ 3,017
Supply management revenues	—	—	1,184
Contracted commercial, industrial and institutional margins (trading margins)	—	74	152
Total operating revenues	64	188	4,353
Operating expenses:			
Purchased power	—	4	3,225
Accrual for payment to CenterPoint	—	—	128
Operation and maintenance	101	110	204
General and administrative	29	76	246
Depreciation and amortization	4	11	26
Total operating expenses	134	201	3,829
Operating (loss) income	(70)	(13)	524
Other loss, net	—	—	(4)
(Loss) earnings before interest and income taxes	$ (70)	$ (13)	$ 520
Margins:			
Retail electricity sales and services margins	$ 64	$110	$ 976
Contracted commercial, industrial and institutional margins (trading margins)	—	74	152
Total	$ 64	$184	$ 1,128
Operations Data:			
Energy sales (GWh):			
Residential			20,932
Small commercial			12,708
Large commercial, industrial and institutional			24,818
Total			58,458
Customers as of December 31, 2002 (in thousands, metered locations):			
Residential			1,478
Small commercial			214
Large commercial, industrial and institutional			24
Total			1,716

2002 Compared to 2001

EBIT. Our retail energy segment's EBIT increased $533 million for 2002 compared to 2001. The increase in EBIT was primarily due to increased margins (revenues less purchased power) related to retail electric sales to residential, small commercial and large commercial, industrial and institutional customers resulting from full competition, which began on January 1, 2002. The increase in margins was partially offset by increased operating expenses as further discussed below.

Operating revenues. Retail electricity sales and services revenues increased $2.9 billion in 2002 compared to 2001 primarily due to retail electric sales in the Texas retail market to residential and small commercial

customers and to the large commercial, industrial and institutional customers in the Houston area that did not sign contracts. Supply management revenues related to the hedging, managing and optimizing of our electric energy supply contributed approximately $1.2 billion of the increase in revenues for 2002.

In addition, $53 million of revenues for 2001 were recorded for billing, customer service, credit and collection and remittance services charged to CenterPoint's regulated electric utility and two of its natural gas distribution divisions. The associated costs are included in operation and maintenance expenses and general and administrative expenses. The retail energy segment charged the regulated electric and gas utilities for the services provided to these utilities at our cost. The service agreement governing these services terminated on December 31, 2001.

Purchased power. Purchased power expense increased $3.2 billion for 2002 due to costs associated with retail electric sales and supply management activity.

Margins. Our retail energy segment's margins increased $944 million for 2002 compared to 2001 due to the opening of the Texas market to full competition in January 2002, as discussed above. During 2002, the retail energy segment recognized $152 million of margins related to commercial, industrial and institutional electricity contracts, including $6 million of unrealized losses, compared to $74 million of margins related to commercial, industrial and institutional electricity contracts, including $73 million of unrealized gains, in 2001. For information regarding the accounting for contracted electricity sales to large commercial, industrial and institutional customers, see notes 2(d) and 2(t) to our consolidated financial statements.

Accrual for payment to CenterPoint. To the extent that our price to beat for electric service to residential and small commercial customers in CenterPoint's Houston service territory during 2002 and 2003 exceeds the market price of electricity, we may be required to make a payment to CenterPoint in 2004. As of December 31, 2002, our estimate for the payment related to residential customers is between $160 million and $190 million, with a most probable estimate of $175 million. For additional information regarding this payment, see note 14(e) to our consolidated financial statements.

Operation and maintenance and general and administrative. Operation and maintenance expenses and general and administrative expenses increased $264 million in 2002 as compared to 2001 primarily due to the following:

- a $59 million increase in gross receipts taxes related to increased retail electric sales;
- a $152 million increase in employee related costs and other administrative costs (including allocated corporate overhead), primarily due to the Texas retail market opening to full competition in January 2002;
- a $77 million increase in bad debt expense associated with the start-up of the retail electric market and regulations which, until September 2002, did not allow us to disconnect customers for non-payment of their electric bills;
- a $23 million increase in marketing costs primarily due to the Texas retail market opening to full competition; and
- a $3 million increase in rent expense as a result of additional staffing.

These increases were partially offset by a decrease of $53 million for billing, customer service, credit and collection and remittance costs, which were charged to CenterPoint's regulated electric utility and two of its natural gas distribution divisions, as discussed above.

Depreciation and amortization. Depreciation and amortization expense increased $15 million in 2002 as compared to 2001 primarily due to depreciation of $17 million related to the information systems developed and placed in service to meet the needs of our retail businesses, offset by lower amortization expense of $2 million.

Retail energy recorded $2 million in 2001 for amortization expense related to goodwill. For information regarding the cessation of goodwill amortization, see note 6 to our consolidated financial statements.

2001 Compared to 2000

EBIT. Our retail energy segment's EBIT loss decreased by $57 million for 2001 compared to 2000. The loss reduction was primarily due to contracts for energy and energy services to large commercial, industrial and institutional customers in 2001, partially offset by (a) increased personnel costs and employee related costs and (b) increased costs associated with developing an infrastructure necessary to prepare for competition in the retail electric market in Texas. Contracted energy sales to large commercial, industrial and institutional customers were accounted for under the mark-to-market method of accounting. These energy contracts were recorded at fair value in revenue upon contract execution. The net changes in their market values were recognized in the income statement in revenue in the period of the change. During 2001, our retail energy segment recognized $74 million of mark-to-market revenues related to commercial, industrial and institutional energy contracts of which $73 million relates to energy that will be supplied in future periods ranging from one to three years.

Operating revenues. Operating revenues increased by $124 million for 2001 compared to 2000 largely due to increased margins from sales of electricity products and services to large commercial, industrial and institutional customers, as well as increased revenues for the billing and remittance services provided to CenterPoint.

Purchased power. Purchased power expense increased by $4 million in 2001 primarily due to costs related to the Texas retail pilot program during the last half of 2001.

Margins. Margins increased $120 million for 2001 compared to 2000 due to the various factors discussed above.

Operation and maintenance and general and administrative. Operation and maintenance costs increased by $9 million and general and administrative expenses increased $47 million in 2001 as compared to 2000, primarily due to $35 million in increased personnel and employee-related costs and costs related to building an infrastructure necessary to prepare for competition in the retail electric market in Texas and $31 million in increased costs incurred in performing billing, customer service, credit and collections and remittance service for CenterPoint.

Wholesale Energy

Our wholesale energy segment includes our non-regulated power generation operations in the United States, which includes acquisition and development of generation facilities, and our wholesale energy trading, marketing, origination and risk management operations in North America. The wholesale energy segment's commercial activities include purchasing fuel to supply existing generation assets, selling electricity and related services produced by these assets, dispatching of the generation portfolios, scheduling of power and natural gas and managing the day-to-day trading and marketing activities.

As of December 31, 2002, we owned or leased electric power generation facilities with an aggregate net operating generating capacity of 19,888 MW in the United States. We acquired our first power generation facility in April 1998, and have increased our aggregate net generating capacity since that time principally through acquisitions, as well as contractual agreements and the development of new generating projects. As of December 31, 2002, we had 2,461 MW (2,658 MW, net of 197 MW to be retired upon completion of one facility) of additional net generating capacity under construction, including facilities having 1,920 MW (2,117 MW, net of 197 MW to be retired upon completion of one facility) that are being constructed by off-balance sheet special purpose entities under construction agency agreements. We expect these facilities to achieve commercial operation in late 2003 or 2004. Effective January 1, 2003, upon adoption of FIN No. 46, we consolidated these special purposes entities, see notes 2(t), 14(b) and 21(a) to our consolidated financial statements.

On May 12, 2000, we purchased entities owning electric power generating assets and development sites located in the PJM Market having an aggregate net generating capacity of approximately 4,262 MW at the acquisition date. For additional information regarding this acquisition of our Mid-Atlantic generating assets, including the accounting treatment of this acquisition, see note 5(b) to our consolidated financial statements.

In February 2002, we acquired all of the outstanding shares of common stock of Orion Power for $2.9 billion and assumed debt obligations of $2.4 billion. Orion Power is an independent electric power generating company with a diversified portfolio of generating assets, both geographically across the states of New York, Pennsylvania, Ohio and West Virginia, and by fuel type, including gas, oil, coal and hydropower. As of February 2002, Orion Power had 81 generating facilities in operation with a total generating capacity of 5,644 MW and two projects under construction with a total generating capacity of 804 MW, which were completed in the second quarter of 2002.

Given the downturn in the industry and downgrades of our credit ratings, in the first half of 2002 we reviewed our trading, marketing, power origination and risk management services strategies and activities. By the third quarter of 2002, we began decreasing the level of these commercial activities in order to significantly reduce collateral usage and focus on the highest return transactions, which are primarily derived from our physical asset positions. In response to declining prices for electric energy, capacity and ancillary services across much of the United States, we also significantly reduced development activities beginning in the second quarter of 2002. Development is now limited only to the completion of projects already under construction. The restructuring of all of our associated commercial, development and support groups resulted in $17 million of severance costs in 2002.

As a result of these restructurings, general and administrative costs are expected to be lower than 2002 levels in the near term.

Starting in late December 2002, our financial gas trading desk carried a spread position, which involved a short position for March 2003 natural gas deliveries and a long position for April 2003 natural gas deliveries. The position was within our authorized value at risk and positional limits. However, there was significant and unanticipated volatility in the natural gas market over a few days in February 2003. As a result, we realized a trading loss of approximately $80 million pre-tax in the first quarter of 2003 related to these positions. These positions have been closed.

In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions.

During 2002, the following factors negatively impacted our wholesale energy segment:

- weaker pricing for electric energy, capacity and ancillary services, as a result of increased capacity brought into the markets and more active regulatory intervention designed to constrain prices in many regions, especially in the western United States;
- a narrowing of the spark spread;
- the effects of market participant contraction;
- reduced liquidity in the United States power markets; and
- our lower credit ratings.

We expect these weak conditions to persist through 2003. However, over the next few years, we anticipate that supply surpluses will begin to tighten, regulatory intervention will become more balanced and as a result, prices for electric energy, capacity and ancillary services will improve.

SFAS No.142 requires goodwill to be tested annually and between annual tests if events occur or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We have elected to perform our annual test for indications of goodwill impairment as of November 1, in conjunction with our annual planning process. Based on our annual impairment test, there was no impairment of our wholesale energy segment's goodwill. Our impairment analysis includes numerous assumptions, including but not limited to:

- increases in demand for power that will result in the tightening of supply surpluses and additional capacity requirements over the next three to eight years, depending on the region;
- improving prices in electric energy, ancillary services and existing capacity markets as the power supply surplus is absorbed; and
- our expectation that more balanced, fair market rules will be implemented, which provide for the efficient operations of unregulated power markets, including capacity markets or mechanisms in regions where they currently do not exist.

These assumptions are consistent with our fundamental belief that long run market prices must reach levels sufficient to support an adequate rate of return on the construction of new power generation. However, if in the long term the current weak environment persists, our wholesale energy segment could have significant impairments of its property and equipment and goodwill. As of December 31, 2002, the wholesale energy segment has $1.5 billion of goodwill.

It is likely that, in order to exercise the Texas Genco option as permitted under our credit facilities, we may sell some of our assets. We have identified certain non-strategic domestic generating assets for potential sale. To date, we have not reached an agreement to dispose of any significant assets of our wholesale energy segment nor have we included or assumed any proceeds from asset sales in our current liquidity plan. Due to unfavorable market conditions in the wholesale power markets, there can be no assurance that we will be successful in disposing of domestic generating assets at reasonable prices or on a timely basis. Specific plans to dispose of assets could result in impairment losses in property, plant and equipment.

In December 2002, we evaluated the Liberty station and the related tolling agreement for impairment. There were no impairments based on our analyses. However, in the future we could incur a pre-tax loss of an amount up to our recorded net book value. For information regarding issues and contingencies related to our Liberty power generation station and the related tolling agreement, see note 14(l) to our consolidated financial statements.

For additional information regarding factors that may affect the future results of operations of our wholesale energy segment, see "—Risk Factors—Risk Related to Our Wholesale Energy Operations."

The following table provides summary data, including EBIT, of our wholesale energy segment for 2000, 2001 and 2002:

	Wholesale Energy Segment		
	Year Ended December 31,		
	2000	2001	2002
	(in millions, except operating data)		
Revenues	$ 2,661	$ 5,382	$ 6,433
Trading margins	198	304	137
Total operating revenues	2,859	5,686	6,570
Operating expenses:			
Fuel and cost of gas sold	911	1,576	1,086
Purchased power	926	2,494	4,196
Operation and maintenance	225	332	579
General, administrative and development	184	259	348
Depreciation and amortization	108	118	337
Total operating expenses	2,354	4,779	6,546
Operating income	505	907	24
Other income:			
Income of equity investment of unconsolidated subsidiaries	43	6	18
Other, net	24	3	26
Earnings before interest and income taxes	$ 572	$ 916	$ 68
Margins:			
Power generation (1)	$ 824	$ 1,312	$ 1,151
Trading	198	304	137
Total	$ 1,022	$ 1,616	$ 1,288
Operations Data (2):			
Wholesale power generation sales volumes (in thousand MWh)	39,300	63,298	129,358
Trading power sales volumes (in thousand MWh)	125,971	222,907	306,425
Trading natural gas sales volumes (Bcf)	2,273	3,265	3,449

(1) Revenues less fuel and cost of gas sold and purchased power.

(2) Includes physically delivered volumes, physical transactions that are settled prior to delivery and hedge activity related to our power generation portfolio.

2002 Compared to 2001

EBIT. The wholesale energy segment's EBIT decreased by $848 million in 2002 compared to 2001. The decline in EBIT is primarily due to the following:

- decreases in our margins from our power generation operations;
- decreases in trading margins; and
- increases in general and administrative expenses.

The decline in EBIT was partially offset by the effect of the acquisition of Orion Power, which closed in February 2002. During 2002, the Orion Power assets contributed $611 million to margins and $222 million to EBIT.

One of the more significant impacts to our wholesale energy segment's EBIT was caused by the FERC staff interpretations of a May 15, 2002 FERC order revising the methodology for calculating refunds of California

energy sales and a March 26, 2003 FERC order on proposed findings on refund liability. During 2002, we recorded a reserve of $176 million for potential refunds, which may be owed by us, which excludes the settlement of $14 million reached with the FERC in January 2003 relating to two days of trading in 2000 (see note 14(i) to our consolidated financial statements). Our inception-to-date reserve for such refunds totals $191 million as of December 31, 2002, excluding the $14 million refund related to the FERC settlement. We estimate the range of our refund obligations for California energy sales to be approximately $191 million to $240 million (excluding the $14 million refund related to the FERC settlement in January 2003). Wholesale energy's EBIT was also impacted by changes to the credit reserve for California receivable balances. The changes in the credit reserves resulted from the FERC refunds described above, collections during the period as well as a determination that credit risk had been reduced on certain outstanding receivables following payments made by one creditor to the California Power Exchange. Accordingly, the credit reserve was reduced by $62 million during 2002. The credit reserve increased by $29 million in 2001. For information regarding the reserves against receivables, the FERC refund methodology and uncertainties in the California wholesale energy market, see notes 14(h) and 14(i) to our consolidated financial statements.

Revenues. Our wholesale energy segment's revenues increased by $1.1 billion or 20% in 2002 compared to 2001. The major components of this increase are: $2.2 billion in revenues in the Mid-Atlantic region as a result of increased hedging, marketing and operating activities and $1.1 billion in revenues contributed by Orion Power, which was acquired in February 2002. These increased revenues were offset by $2.2 billion in lower generation volumes and reduced hedging and marketing activities in regions other than the Mid-Atlantic and lower prices for electric energy and ancillary services.

Fuel and cost of gas sold and purchased power. Our wholesale energy segment's fuel and cost of gas sold and purchased power increased by $1.2 billion in 2002 due primarily to $2.3 billion in the Mid-Atlantic region as a result of hedging and marketing activities and an increase of $444 million due to Orion Power. This was partially offset by a $1.7 billion reduction of generation volumes, reduced hedging and marketing activities and lower prices for fuel in the California region.

Trading margins. Trading margins, excluding a $5 million provision related to Enron recorded in 2001, decreased $172 million primarily as a result of lower commodity volatility in the power markets, reduced market liquidity driven by the industry's restructuring and the reduction of our trading activities as a result of our restructuring, as discussed above.

Power generation margins. Our wholesale energy segment's power generation margins decreased $161 million in 2002 compared to 2001. Power generation margins in the wholesale energy segment were negatively impacted by the following:

- a $751 million decrease in power generation margins in the West region due to (a) the loosening of tight supply and demand conditions that existed in the first six months of 2001, (b) increased refund requirements discussed above, (c) a full year of energy price caps which were initially implemented in June 2001 and (d) other regulatory provisions that suppressed ancillary services revenues;
- a $76 million decrease in power generation margins in the Mid-Atlantic Region in 2002 due to a decline in power prices and reduced capacity revenues as a result of the expiration of a large capacity contract and lower capacity market conditions, which were primarily a result of increased generation supply in the region as well as regulatory intervention;
- a $68 million decrease in our other smaller regions mainly due to decreases in power prices, losses on our tolling contracts and increased gas transportation costs in 2002;
- increased fuel transportation costs for new projects; and
- a $33 million decrease due to the ineffectiveness of cash flow hedges from a $31 million gain in 2001 primarily related to the California market (see note 1 to our consolidated financial statements) to a $2 million loss in 2002.

These unfavorable variances were partially offset by the following:

- $611 million in power generation margins from the Orion Power acquisition that closed in February 2002 and
- $93 million in power generation margins from new plants that became commercially operational in the second half of 2001 and throughout the first half of 2002.

In addition, the results for 2001 included a $63 million provision against net receivables, trading and marketing assets and non-trading derivative balances related to Enron.

Operation and maintenance. Operation and maintenance expenses for our wholesale energy segment increased $247 million in 2002 compared to 2001. This was primarily due to $254 million of operation and maintenance expenses of our Orion plants acquired in February 2002 and $21 million from new plants that became commercially operational in the second half of 2001 and throughout the first half of 2002, slightly offset by reduced expenses of $27 million as a result of lower maintenance and outage costs in the West and Mid-Atlantic regions.

General, administrative and development. General, administrative and development expenses increased $89 million in 2002 compared to 2001, primarily due to the following:

- $26 million of higher corporate overhead allocations to support wholesale commercial activities, including the integration of Orion Power;
- $20 million of severance expense primarily related to our restructuring discussed above;
- $11 million of consulting costs incurred in connection with our restructuring of plant operations and commercial activities and support groups; and
- $9 million of general bad debt expense due to the financial deterioration of counterparties in the wholesale energy industry in 2002.

In addition, during 2002, our wholesale energy segment incurred $14 million in increased expenses related to development activities, which includes $27 million of write-offs in 2002 in previously capitalized costs related to projects that have been terminated partially offset by $9 million of development cost write-offs in 2001.

Depreciation and amortization. Depreciation and amortization expense increased by $219 million in 2002 compared to 2001 primarily as a result of the following:

- $110 million in depreciation expense related to our Orion Power plants;
- $23 million in depreciation expense for other generating plants placed into service during the second half of 2001 and throughout the first half of 2002;
- a $37 million equipment impairment charge related to turbines and generators;
- $16 million in depreciation expense associated with new information technology systems placed into service in 2002; and
- a $15 million write-off for the closure of our Warren power plant in Pennsylvania.

In addition, during 2002, emission credit amortization increased $10 million due to increased amortization of $25 million resulting from the Orion acquisition in February 2002. These were partially offset by $19 million of lower amortization of air emission allowances primarily related to our California power generation operations. For 2001, wholesale energy recorded $4 million in goodwill amortization expense. For information regarding the cessation of goodwill amortization, see note 6 to our consolidated financial statements.

Income of equity investment of unconsolidated subsidiaries. Our wholesale energy segment reported $18 million in income from equity investments for 2002 compared to $6 million in 2001. The equity income in both years primarily resulted from an investment in an electric generation plant in Boulder City, Nevada. The equity income related to this investment increased during 2002 compared to 2001, primarily due to receipts of $22 million from business interruption and property/casualty insurance settlements, partially offset by decreases in margins due to lower prices realized in 2002.

Other income, net. Other non-operating income increased $23 million in 2002 compared to 2001 primarily due to billings for software services, engineering and technical support services, and other services to support operations and maintenance of generating facilities of Texas Genco.

2001 Compared to 2000

EBIT. Our wholesale energy segment's EBIT increased $344 million in 2001 compared to 2000. The increase in EBIT was primarily due to increased power generation margins from our generation facilities and increased trading margins. The increases in power generation margins and trading margins were partially offset by increased operating expenses and a decrease in other income as further discussed below. The results for 2001 include a $68 million provision against net receivables, trading and marketing assets and non-trading derivative balances related to Enron, and a $29 million credit provision and a $15 million net write-off against receivable balances related to energy sales in California. A $39 million provision against receivable balances related to energy sales in California was recorded in 2000.

Revenues. Our wholesale energy segment's revenues increased by $2.7 billion (102%) in 2001 compared to 2000. The major components of this increase were $1.6 billion from our California operations due to hedging and marketing activities and the factors discussed above, and $1.0 billion from our Mid-Atlantic region assets as a result of favorable hedging and marketing and operating results.

Fuel and cost of gas sold and purchased power. Our wholesale energy segment's fuel and cost of gas sold and purchased power increased by $2.2 billion in 2001 compared to 2000 due primarily to $1.3 billion from the California operations and $928 million from our Mid-Atlantic assets as a result of hedging and marketing activities.

Trading margins. Trading and marketing margins, excluding a $5 million provision related to Enron, increased $111 million primarily as a result of increased natural gas trading volumes.

Power generation margins. Power generation margins for our wholesale energy segment increased by $488 million primarily due to increased volumes on power sales from our generation facilities, and the addition of our Mid-Atlantic assets in May 2000 and strong commercial and operational performance in other regions. Margins on power sales from our generation facilities increased by the following amounts by region in 2001 compared to 2000 (and exclude a $63 million provision related to Enron):

- $389 million in the West region;
- $85 million in the Mid-Atlantic region;
- $29 million in other regions; and
- $31 million due to the ineffectiveness of cash flow hedges in 2001 primarily related to the California market.

Favorable market conditions in the first six months of 2001 in the West region resulting from a combination of factors, including reduction in available hydroelectric generation resources, increased demand and decreased electric imports, positively impacted wholesale energy's operating margins. These favorable market conditions did not exist in the second half of 2001.

Operation and maintenance. Operation and maintenance expenses for wholesale energy increased $107 million in 2001 compared to 2000, primarily due to $50 million of costs associated with the operation and maintenance of generating plants acquired in the Mid-Atlantic region and $38 million higher lease expense associated with the Mid-Atlantic generation facilities' sale-leaseback transactions that were entered into in August 2000.

General, administrative and development. General, administrative and development expenses increased $75 million in 2001 compared to 2000, primarily due to $69 million of higher administrative costs to support growing wholesale commercial activities and $25 million of higher legal and regulatory expenses related to the West region, partially offset by a $12 million decrease in development expenses.

Depreciation and amortization. Depreciation and amortization expense increased by $10 million in 2001 compared to 2000 primarily as a result of higher expense related to the depreciation of our Mid-Atlantic plants, which were acquired in May 2000, and other generating plants placed into service during 2001, partially offset by an $8 million decrease in amortization of our air emissions regulatory allowances.

Income of equity investment of unconsolidated subsidiaries. Our wholesale energy segment reported income from equity investments for 2001 of $6 million as compared to $43 million in 2000. The equity income in both years primarily resulted from an investment in an electric generation plant in Boulder City, Nevada. The plant became operational in May 2000. The equity income related to our investment in the plant declined in 2001 from 2000 primarily due to higher plant outages in 2001 and reduced power prices realized by the project company.

Other income, net. Other income, net, decreased by $21 million in 2001 compared to 2000 primarily as a result of an $18 million pre-tax gain in 2000 on the sale of our interest in one of our development-stage electric generation projects.

European Energy

Our European energy segment generates and sells power from its generation facilities in the Netherlands and participates in the wholesale energy trading and origination industry in Northwest Europe.

In February 2003, we signed a share purchase agreement to sell our European energy operations to Nuon, a Netherlands-based electricity distributor. Upon consummation of the sale, we expect to receive cash proceeds from the sale of approximately $1.2 billion (Euro 1.1 billion). We intend to use the cash proceeds from the sale first to prepay the Euro 600 million bank term loan borrowed by Reliant Energy Capital (Europe), Inc. to finance a portion of the acquisition costs of our European energy operations. The maturity date of the credit facility, which originally was scheduled to mature in March 2003, has been extended (see notes 9(a) and 21(c) to our consolidated financial statements). We intend to use the remaining cash proceeds of approximately $0.5 billion (Euro 0.5 billion) to partially fund our option to acquire Texas Genco in 2004 (see note 4(b) to our consolidated financial statements). However, if we do not exercise the option, we will use the remaining cash proceeds to prepay debt.

We recognized a loss of approximately $0.4 billion in the first quarter of 2003 in connection with the anticipated sale. We do not anticipate that there will be a Dutch or United States income tax benefit realized by us as a result of the $0.4 billion loss. In addition, we recognized an impairment of the full amount of our European energy segment's net goodwill of $482 million in the fourth quarter of 2002, as further discussed below. We will recognize contingent payments, if any, in earnings upon receipt. In the first quarter of 2003, we began to report the results of our European energy operations as discontinued operations in accordance with SFAS No. 144. For further discussion of the sale, see note 21(b) to our consolidated financial statements.

Based on our annual impairment test as of November 1, 2002, we recognized an impairment of the full amount of our European energy segment's net goodwill of $482 million in the fourth quarter of 2002. As we

signed a share purchase agreement to sell our European energy operations in February 2003 (as discussed above), the sales price reflects the best estimate of fair value of our European energy segment as of November 1, 2002, to use in our annual impairment test. For additional information regarding this goodwill impairment and this transaction and the related impacts, see notes 6 and 21(b) to our consolidated financial statements.

During the third quarter of 2002, we completed the transitional impairment test for the adoption of SFAS No. 142, including the review of goodwill for impairment. Based on this impairment test, we recorded an impairment of the European energy segment's goodwill of $234 million, net of tax. This impairment loss was recorded retroactively as a cumulative effect of a change in accounting principle for the quarter ended March 31, 2002. The circumstances leading to this impairment of our European energy segment's goodwill included a significant decline in electric margins attributable to the deregulation of the European electricity market in 2001, lack of growth in the wholesale energy trading markets in Northwest Europe, continued regulation of certain European fuels markets, and the reduction of proprietary trading in our European operations. For further discussion of the impairment, see note 6 to our consolidated financial statements.

In September 2002, we concluded a comprehensive evaluation of our European energy segment's businesses and it was decided that proprietary trading would be significantly reduced in order to focus on commercial activities around our power generation assets and wholesale customers in the Netherlands. Accordingly, in the third quarter of 2002, we announced the closure of our London-based natural gas and electricity trading operations. In addition, we have consolidated facilities, centralized activities and reduced personnel in Amsterdam and Frankfurt. As a result, our European energy segment recorded an $8 million reorganization charge in 2002, primarily related to severance, in operating and maintenance and general and administrative expenses.

For additional information regarding factors that may affect the future results of operations of our European energy segment, see "—Risk Factors—Risks Related to Our European Energy Operations."

The following table provides summary data, including EBIT of our European energy segment for 2000, 2001 and 2002:

	European Energy Segment		
	Year Ended December 31,		
	2000	2001	2002
	(in millions, except operating data)		
Revenues	$ 544	$ 623	$ 611
Trading margins	2	(9)	21
Total operating revenues	546	614	632
Operating expenses:			
Fuel	260	400	357
Purchased power	—	11	(40)
Operation and maintenance	87	30	117
General and administrative	39	41	29
Goodwill impairment	—	—	482
Depreciation and amortization	76	76	58
Total operating expenses	462	558	1,003
Operating income (loss)	84	56	(371)
Other income:			
Income of equity investment of unconsolidated subsidiaries	—	51	5
Other, net	5	6	10
Earnings (loss) before interest and income taxes	$ 89	$ 113	$ (356)
Margins:			
Power generation (1)	$ 284	$ 212	$ 294
Trading	2	(9)	21
Total	$ 286	$ 203	$ 315
Electricity (in thousand MWh):			
Power generation sales	11,606	16,344	17,794
Trading sales	1,091	25,232	71,660

(1) Revenues less fuel and purchased power.

2002 Compared to 2001

EBIT. Our European energy segment's EBIT decreased $469 million during 2002 as compared to 2001 due to a $482 million goodwill impairment in the fourth quarter of 2002, as discussed above, and to a lesser extent increased operation and maintenance and general and administrative expenses and decreased equity investment income, as explained below. These decreases were partially offset by increased margins of $112 million. During the second quarter of 2002, our European energy segment recognized a one-time $109 million gain resulting from the amendment of our stranded cost electricity supply contracts which is recorded as a reduction in purchased power expense and is included in power generation margins. For additional discussion regarding the amendment of these contracts, see note 14(j) to our consolidated financial statements.

Revenues. Our European energy segment's revenues decreased $12 million for 2002 compared to 2001. Contributing to the decline from 2001 was a non-recurring efficiency and energy payment of $30 million received during the second quarter of 2001 from NEA, which was the coordinating body for the Dutch electric generating sector prior to wholesale competition. In addition, ancillary services and district heating revenues decreased by a combined total of $12 million and during the fourth quarter of 2002 we recognized a $6 million

reduction in revenues related to the bankruptcy of an European subsidiary of TXU Corp. Partially offsetting these decreases in revenues was $21 million in increased electricity sales and an $11 million favorable foreign exchange effect.

Trading margins. Trading margins increased $30 million for 2002 compared to 2001 primarily due to a $14 million increase in green power origination transactions and a $17 million provision recorded in 2001 against receivable and trading and marketing asset balances related to Enron. During the third quarter of 2002, we ceased, in all material respects, trading on a proprietary basis. In addition, overall market liquidity has reduced in the European power markets from prior years.

Fuel and purchased power. Fuel and purchased power costs decreased $94 million for 2002 compared to 2001 primarily due to a one-time $109 million gain as discussed above and a net $19 million gain related to changes in the mark-to-market valuation of certain out-of-market contracts in 2002, partially offset by $9 million of unfavorable foreign exchange effect. In addition, higher electricity sales levels have driven comparatively higher levels of fuel consumption and purchased power during 2002 as compared to 2001.

Power generation margins. Power generation margins increased $82 million for 2002 compared to 2001 due to the various factors discussed above. In addition, we estimate unplanned plant outages had a $10 million negative power generation margins impact during 2002 compared to an $11 million negative impact during 2001.

Operation and maintenance and general and administrative. Operation and maintenance and general and administrative expenses increased by $75 million for 2002 compared to 2001 primarily due to the following:

- a $37 million net gain recorded in operation and maintenance expense related to the settlement, during December 2001, of the former shareholder's indemnity obligation related to out-of-market contracts (see note 14(j) to our consolidated financial statements);
- $8 million in reorganization and severance charges associated with our business restructuring in 2002 as discussed above;
- $8 million reversal of a reserve for environmental tax subsidies receivable in 2001;
- $6 million increase in employee benefit expenses in 2002;
- $6 million increase in legal, consulting and environmental fees in 2002; and
- $9 million unfavorable foreign exchange effect.

These items were partially offset by a $6 million decrease in corporate overhead allocations.

Goodwill impairment. As further described above, during the fourth quarter of 2002, our European energy segment recognized a $482 million impairment of the full amount of its net goodwill.

Depreciation and amortization. Depreciation and amortization expense decreased $18 million for 2002 compared to 2001 primarily due to the cessation of goodwill amortization effective January 1, 2002. During 2001, European energy recorded $26 million in goodwill amortization expense. This decrease was partially offset by a $5 million increase in depreciation expense as a result of capital expenditures in late 2001 associated with our trading business and a $3 million favorable foreign exchange effect.

Other income, net. Other non-operating income decreased $42 million during 2002 compared to 2001 primarily due to a $51 million gain recorded in the second quarter of 2001, as equity income for the preacquisition gain contingency related to the acquisition of REPGB for the value of its equity investment in NEA. For further discussion of this gain, see note 14(j) to our consolidated financial statements. This decrease in equity income was partially offset by equity income for 2002 of $5 million.

2001 Compared to 2000

EBIT. Our European energy segment's EBIT increased by $24 million for 2001 compared to 2000. This increase was primarily due to a $51 million gain recorded in the second quarter of 2001, within income of equity investments of unconsolidated subsidiaries, as described above, and a decrease of operation and maintenance expenses, as discussed below. This increase in EBIT was partially offset by an $83 million decrease in margins, as discussed below.

Revenues. Our European energy segment's revenues increased $79 million during 2001 as compared to 2000. This increase was primarily due to the following:

- a $30 million efficiency and energy payment from NEA in 2001, as described above;
- $33 million increase in ancillary services due to the imbalance market created by the liberalization of the wholesale energy market;
- $23 million in higher district heating revenues due to colder weather as well as growth in certain districts; and
- $9 million increase in electric generation sales.

Partially offsetting these increases in revenues was a $16 million unfavorable foreign exchange effect.

Trading margins. Trading margins decreased $11 million from $2 million in margins in 2000 to $9 million in margins loss in 2001 primarily as a result of a $17 million provision against receivable and trading and marketing asset balances related to Enron, as discussed above. Excluding this provision, trading margins increased $6 million primarily due to a significant increase in trading revenues in the Dutch, German and Austrian power markets, power trading volumes, trading origination transactions and increased volatility in the Dutch and German markets.

Fuel and purchased power. Fuel and purchased power costs increased $151 million for 2001 compared to 2000 primarily due to higher natural gas prices, increased output from our generating facilities and increased transmission and grid charges as a result of a change in the tariff structure. Partially offsetting this increase in fuel and purchased power costs was a $14 million favorable foreign exchange effect.

Power generation margins. Power generation margins decreased $72 million for 2001 compared to 2000 due to the various factors discussed above. Further contributing to the decline in operating margins were a number of unscheduled outages at our electric generating facilities. We estimate that these unplanned outages resulted in losses of $11 million in 2001.

Operation and maintenance and general and administrative. Operation and maintenance and general and administrative expenses decreased by $55 million for 2001 compared to 2000. These expenses declined primarily due to the following:

- the net gain of $37 million recorded in operation and maintenance expenses related to the settlement of the former shareholders' indemnity obligation;
- provisions in 2000 against environmental tax subsidies receivable from Dutch distribution companies, REPGB's former shareholders and the Dutch government, coupled with the reversal of such accrual in 2001 due to the indemnity obligation settlement with REPGB's former shareholders; and
- a $6 million decrease in provisions for environmental liabilities, employee benefits and other accruals.

This decrease was partially offset by an increase in personnel and operating expenses related to our trading operations, facilities costs and systems upgrades.

Other income, net. Other non-operating income increased $52 million during 2001 compared to 2000 primarily due to a $51 million gain recorded in the second quarter of 2001, within income of equity investments of unconsolidated subsidiaries, as described above.

Other Operations

Our other operations segment includes the operations of our venture capital business and unallocated corporate costs.

During the third quarter of 2001, we decided to exit our communications business. The business served as a facility-based competitive local exchange carrier and Internet services provider and owned network operations centers and managed data centers in Houston and Austin. Our exit plan was substantially completed in the first quarter of 2002.

The following table provides summary data regarding the results of operations for our other operations segment for 2000, 2001 and 2002:

	Other Operations Segment		
	Year Ended December 31,		
	2000	2001	2002
	(in millions)		
Operating revenues	$ 6	$ 11	$ 3
Operating expenses:			
Operation and maintenance	9	21	3
General and administrative	52	128	42
Depreciation and amortization	6	42	15
Total operating expenses	67	191	60
Operating loss	(61)	(180)	(57)
Other income (expenses):			
(Loss) gain from investments	(26)	23	(23)
Other, net	4	(1)	—
Loss before interest and income taxes	$(83)	$(158)	$(80)

2002 Compared to 2001

Other operations' loss before interest and income taxes declined by $78 million for 2002 compared to 2001. The decline in loss before interest and income taxes is primarily due to the following:

- a $100 million pre-tax, non-cash charge recorded in the first quarter of 2001 relating to the redesign of some of CenterPoint's benefit plans in anticipation of our separation from CenterPoint;
- $35 million in restructuring charges and $19 million of goodwill impairment related to the exiting of our communications business recognized during the third quarter of 2001; and
- $18 million in decreased operating losses related to our communications business.

Partially offsetting these items are a $47 million net pre-tax, non-cash accounting settlement charge recognized during the third quarter of 2002 for certain benefit obligations associated with our separation from CenterPoint, and a $12 million increase in depreciation expense related to corporate assets. In addition, other income decreased $45 million during 2002 compared to 2001, primarily due to $14 million in decreased gains

from investments coupled with a $32 million impairment of certain venture capital investments. For further discussion on these investments and the related impairments, see note 2(o) to our consolidated financial statements.

In connection with our decision to exit the communication business, we determined that the goodwill associated with the communications business was impaired. We recorded $54 million of pre-tax disposal charges in 2001, including the impairment of goodwill of $19 million and fixed assets of $22 million, and $13 million in severance accruals, lease cancellation costs and other incremental costs associated with exiting the communications business. The goodwill and fixed asset impairments are included in depreciation and amortization expense.

For additional information about the benefit charges noted above, see notes 12(b) and 12(d) to our consolidated financial statements.

2001 Compared to 2000

Other operation's loss before interest and income taxes increased by $75 million for 2001 compared to 2000. During 2001, we recognized $54 million of restructuring charges related to exiting our communications business as discussed above. In addition, we incurred a $100 million non-cash charge during 2001 relating to the redesign of some of CenterPoint's benefit plans in anticipation of our separation from CenterPoint. These items were partially offset by a $44 million increase in other income primarily due to a $27 million impairment loss incurred in 2000 on marketable equity securities, classified as "available-for-sale", as a result of various factors which caused our management to believe the declines in fair value to be other than temporary, and a $22 million increase in gains from equity and debt securities. A decrease of $12 million in corporate operating expenses and a decrease of $15 million in charitable contributions of equity securities also slightly offset the increase in the loss before interest and income taxes. For information regarding the $27 million impairment loss incurred in 2000, see note 2(o) to our consolidated financial statements.

Trading and Marketing Operations

Trading and marketing activities include (a) transactions establishing open positions in the energy markets, primarily on a short-term basis, (b) transactions intended to optimize our power generation portfolio, but which do not qualify for hedge accounting and (c) energy price risk management services to customers primarily related to natural gas, electric power and other energy-related commodities. We provide these services by utilizing a variety of derivative instruments (trading energy derivatives). We account for these transactions under mark-to-market accounting. For information regarding mark-to-market accounting, see notes 2(t) and 7 to our consolidated financial statements. Specifically, these trading and marketing activities consist of the following:

- the large contracted commercial, industrial and institutional customers under retail electricity contracts and the related energy supply contracts of our retail energy segment entered into prior to October 25, 2002;
- the domestic energy trading, marketing, risk management services to our customers and certain power origination activities of our wholesale energy segment; and
- the European energy trading and origination operations of our European energy segment.

During 2002, we evaluated our trading, marketing, power origination and risk management services strategies and activities. During the second half of 2002, we began to reduce our wholesale energy segment's trading, marketing and power origination activities due to liquidity concerns and in order to significantly reduce collateral usage and focus on the highest return transactions, which primarily relate to our physical asset positions. In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent

practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions.

In October 2002, the EITF rescinded EITF No. 98-10. For further discussion of the impact on our consolidated financial statements, see "—EBIT by Business Segment—Retail Energy" and "EBIT by Business Segment—Wholesale Energy" in Item 7 of this Form 10-K/A and notes 2(t) and 7 to our consolidated financial statements.

For additional information regarding the types of contracts and activities of our trading and marketing operations, see "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K/A and note 7 to our consolidated financial statements.

The following table sets forth our net trading and marketing assets (liabilities) by segment as of December 31, 2001 and 2002:

	As of December 31,	
	2001	2002
	(in millions)	
Retail energy	$ 73	$ 94
Wholesale energy	154	105
European energy	(9)	(9)
Net trading and marketing assets and liabilities	$218	$190

The following table sets forth our realized and unrealized trading, marketing and risk management services margins for 2000, 2001 and 2002:

	Year Ended December 31,		
	2000	2001	2002
		(in millions)	
Realized	$202	$184	$334
Unrealized	(2)	186	(24)
Total	$200	$370	$310

Below is an analysis to our consolidated net trading and marketing assets and liabilities for 2001 and 2002:

	Year Ended December 31,	
	2001	2002
	(in millions)	
Fair value of contracts outstanding, beginning of the year	$ 32	$ 218
Fair value of new contracts when entered into during the year	119	57
Contracts realized or settled during the year	(184)	(334)
Changes in fair values attributable to changes in valuation techniques and assumptions	(23)	31
Changes in fair values attributable to market price and other market changes	274	218
Fair value of contracts outstanding, end of the year	$ 218	$ 190

During 2001 and 2002, our retail energy segment entered into electric sales contracts with large commercial, industrial and institutional customers ranging from one-half to four years in duration. These contracts had an

aggregate fair value of $97 million in 2001 at the contract inception dates. Subsequent to the inception dates, the fair values of these contracts were adjusted to $74 million during 2001 due to changes in assumptions used in the valuation models, as described below. During 2002, we recognized total fair value of $43 million for these contracts at the inception dates. We have entered into energy supply contracts to substantially hedge the economics of these contracts. The fair value of these retail energy segment electric sales contracts with large commercial, industrial and institutional customers was determined by comparing the contract price to an estimate of the market cost of delivered retail energy and applying the estimated volumes under the provisions of these contracts. The calculation of the estimated cost of energy involves estimating the customer's anticipated load volume, and using forward ERCOT OTC commodity prices, adjusted for the customer's anticipated load characteristics. Load characteristics in the valuation model include: the customer's expected hourly electricity usage profile, the potential variability in the electricity usage profile (due to weather or operational uncertainties), and the electricity usage limits included in the customer's contract. The delivery costs are estimated at the time sales contracts are executed. These costs are based on published rates and our experience of actual delivery costs. Examples of these delivery costs include electric line losses and unaccounted for energy, ERCOT ISO administrative fees, market interaction charges, and may include transmission and distribution fees. The remaining weighted-average duration of these contracts is approximately sixteen months as of December 31, 2002.

Our retail energy segment also enters into supply contracts to substantially hedge the economics of the sales contracts entered into with large commercial, industrial and institutional customers. During 2001 and 2002, we recognized total fair value of $5 million and $8 million, respectively, related to these contracts at the inception dates. The fair values of these contracts are estimated using ERCOT OTC forward price and volatility curves and correlations among power and fuel prices specific to the ERCOT Region, net of credit risk. For the contracts extending beyond December 31, 2002, the remaining weighted-average duration of these contracts, based on volumes, is one year.

During 2001 and 2002, the fair value of new contracts recorded at inception of $17 million and $6 million, respectively, primarily relates to power purchases and sales and natural gas transportation contracts entered into by the wholesale energy segment. The fair values of these wholesale energy contracts at inception are estimated using OTC forward price and volatility curves and correlation among power and fuel prices, net of estimated credit risk. For the contracts extending beyond December 31, 2002, the remaining weighted-average duration of these contracts, based on volumes, is four years.

During 2002, our retail energy segment eliminated one valuation factor adjustment and added another to its fair value calculation. Our retail energy segment eliminated a valuation factor for potential claims for delays in switching under the liquidated damage clauses in contracts. Retail energy eliminated this valuation factor because there is now enough data to substantiate that these claims will not be submitted. This change in methodology reduced credit reserves by $5 million. Our retail energy segment added a valuation factor adjustment to capture the potential earnings loss associated with customers terminating contracts due to a provision in some of its contracts that allows customers to terminate their contracts if our unsecured debt ratings fall below investment grade or if our ratings are withdrawn entirely by a rating agency. During the third quarter of 2002, each of the major rating agencies downgraded our credit ratings to sub-investment grade. We performed an analysis at the customer level to estimate our exposure for these provisions. To date, no customers have terminated according to this provision. This change in methodology increased credit reserves by $1 million. Our retail energy segment also changed the methodology related to recording its estimate of unaccounted for energy. Our retail energy segment changed its estimate of unaccounted for energy factor from 1.6% to zero. The reason for the change is that the retail energy segment believes the estimate of unaccounted for energy is included in its volatility valuation factor and its results from energy sales in 2001 were not negatively impacted by the estimate of unaccounted for energy. This change in methodology reduced credit reserves by $9 million.

In addition, during 2002, we changed our methodology for allocating credit reserves between our trading and non-trading portfolios. Total credit reserves calculated for both the trading and non-trading portfolios, which are less than the sum of the independently calculated credit reserves for each portfolio due to common counterparties between the portfolios, are allocated to the trading and non-trading portfolios based upon the independently calculated trading and non-trading credit reserves. Previously, credit reserves were independently calculated for the trading portfolio while credit reserves for the non-trading portfolio were calculated by deducting the trading credit reserves from the total credit reserves calculated for both portfolios. This change in methodology reduced credit reserves relating to the trading portfolio by $18 million.

The following table sets forth the fair values of the contracts related to our trading and marketing assets and liabilities as of December 31, 2002:

	Fair Value of Contracts at December 31, 2002						
Source of Fair Value	**2003**	**2004**	**2005**	**2006**	**2007**	**2008 and thereafter**	**Total fair value**
				(In millions)			
Prices actively quoted	$ 4	$(16)	$—	$—	$—	$—	$(12)
Prices provided by other external sources	147	40	4	—	—	—	191
Prices based on models and other valuation methods	(33)	2	3	9	13	17	11
Total	$118	$ 26	$ 7	$ 9	$ 13	$ 17	$190

The following table sets forth the fair values of the contracts recognized as derivatives under SFAS No. 133 which were previously recorded as trading and marketing assets and liabilities as of January 1, 2003, after the effect of the adoption of EITF No. 02-03 has been recorded as a cumulative effective of a change in accounting principle (see notes 2(d) and 2(t) to our consolidated financial statements):

	Fair Value of Contracts at January 1, 2003						
Source of Fair Value	**2003**	**2004**	**2005**	**2006**	**2007**	**2008 and thereafter**	**Total fair value**
				(In millions)			
Prices actively quoted	$ 4	$(16)	$—	$—	$—	$—	$(12)
Prices provided by other external sources	131	40	4	—	—	—	175
Prices based on models and other valuation methods	(44)	(9)	(5)	2	9	10	(37)
Total	$ 91	$ 15	$ (1)	$ 2	$ 9	$ 10	$126

The "prices actively quoted" category represents our New York Mercantile Exchange (NYMEX) futures positions in natural gas and crude oil. NYMEX has quoted prices for natural gas and crude oil for the next 72 and 30 months, respectively.

The "prices provided by other external sources" category represents our forward positions in natural gas and power at points for which OTC broker quotes are available. On average, OTC quotes for natural gas and power extend 36 and 24 months into the future, respectively. We value these positions against internally developed forward market price curves that are frequently validated and recalibrated against OTC broker quotes. This category also includes some transactions whose prices are obtained from external sources and then modeled to hourly, daily or monthly prices, as appropriate.

The "prices based on models and other valuation methods" category contains (a) the value of our valuation adjustments for liquidity, credit and administrative costs, (b) the value of options not quoted by an exchange or OTC broker, (c) the value of transactions for which an internally developed price curve was constructed as a result of the long-dated nature of the transaction or the illiquidity of the market point, and (d) the value of structured transactions. In certain instances structured transactions can be composed and modeled by us as simple forwards and options based on prices which are actively quoted. Options are typically valued using Black-Scholes option valuation models. Although the valuation of the simple structures might not be different

from the valuation of contracts in other categories, the effective model price for any given period is a combination of prices from two or more different instruments and therefore has been included in this category due to the complex nature of these transactions.

The fair values in the above table are subject to significant changes based on fluctuating market prices and conditions. Changes in the assets and liabilities from trading, marketing, power origination and price risk management services result primarily from changes in the valuation of the portfolio of contracts, newly originated transactions and the timing of settlements. The most significant parameters impacting the value of our portfolio of contracts include natural gas and power forward market prices, volatility and credit risk. For the retail energy segment sales discussed above, significant variables affecting contract values also include the variability in electricity consumption patterns due to weather and operational uncertainties (within contract parameters). Market prices assume a normal functioning market with an adequate number of buyers and sellers providing market liquidity. Insufficient market liquidity could significantly affect the values that could be obtained for these contracts, as well as the costs at which these contracts could be hedged. Please read "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K/A for further discussion and measurement of the market exposure in the trading and marketing businesses and discussion of credit risk management.

Credit Risk. Credit risk is inherent in our commercial activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. We have broad credit policies and parameters set by our risk oversight committee. The credit risk control organizations prepare daily analyses of credit exposures. We seek to enter into contracts that permit us to net receivables and payables with a given counterparty. We also enter into contracts that enable us to obtain collateral from a counterparty as well as to terminate upon the occurrence of certain events of default.

It is our policy that all transactions must be within approved counterparty or customer credit limits. For each business segment, the credit risk control organization establishes counterparty credit limits. We employ tiered levels of approval authority for counterparty credit limits, with authority increasing from the credit risk control organization through senior management and the risk oversight committee. The credit risk control organization monitors credit exposure daily. We periodically review the financial condition of our counterparties.

We assess our credit risk and exposure by counterparty taking into consideration both our trading and marketing assets and non-trading derivatives with each counterparty.

The following table sets forth the distribution by credit ratings of our trading and marketing assets and non-trading derivative assets as of December 31, 2002, after taking into consideration netting within each contract and any master netting contracts with counterparties :

Credit Rating Equivalent	Exposure	Collateral Held (1)	Exposure Net of Collateral	Percentage of Exposure Net of Collateral
		(in millions)		
AAA/Aaa	$ 1	$ —	$ 1	— %
AA-/Aa3 or above	139	(70)	69	10%
A-/A3 or above	118	—	118	17%
BBB-/Baa3 or above	315	(53)	262	38%
BB+/Ba1 or below	276	(64)	212	30%
Unrated (2)(3)	32	(1)	31	5%
	881	(188)	693	100%
Less: Credit and other reserves	(68)	—	(68)	
Total	$813	$(188)	$625	

(1) Collateral consists of cash and standby letters of credit.
(2) For unrated counterparties, we perform financial statement analyses, considering contractual rights and restrictions, and collateral, to create an internal credit rating.
(3) In lieu of making an individual assessment of the credit of unrated counterparties, we may make a determination that the collateral held in respect of such obligations is sufficient to cover a substantial portion of our exposure. In making this determination, we take into account various factors, including market volatility.

The following table sets forth the credit exposure by maturity for total trading and marketing assets and non-trading derivative assets as of December 31, 2002:

Credit Rating Equivalent	0-12 Months	1 Year or Greater	Exposure Net of Collateral (1)
	(in millions)		
AAA/Aaa	$ 1	$—	$ 1
AA-/Aa3 or above	110	29	69
A-/A3 or above	100	18	118
BBB-/Baa3 or above	281	34	262
BB+/Ba1 or below	148	128	212
Unrated (2)(3)	29	3	31
	669	212	693
Less: Credit and other reserves	(30)	(38)	(68)
Total	$639	$174	$625

(1) Collateral consists of cash and standby letters of credit.
(2) For unrated counterparties, we perform credit analyses, considering contractual rights and restrictions, and credit support such as parent company guarantees to create an internal credit rating.
(3) In lieu of making an individual assessment of the credit of unrated counterparties, we may make a determination that the collateral held in respect of such obligations is sufficient to cover a substantial portion of our exposure. In making this determination, we take into account various factors, including market volatility.

Trading and marketing assets and liabilities and non-trading derivative assets and liabilities are presented separately in our consolidated balance sheets. The trading and non-trading derivative asset and trading and non-trading derivative liability balances were offset separately for trading and non-trading activities although in certain cases contracts permit the offset of trading and non-trading derivative assets and liabilities with a given counterparty. For the purpose of disclosing credit risk, trading and non-trading derivative assets and liabilities with a given counterparty were offset if the counterparty has entered into a contract with us which permits netting.

The credit distribution as of December 31, 2002 includes a larger percentage of non-investment grade counterparties compared to our credit exposure as of December 31, 2001. This is primarily attributable to the credit rating downgrades that took place within the energy sector during 2002. As of December 31, 2001, no individual counterparty accounted for more than 10% of our total credit exposure, net of collateral. As of December 31, 2002, one counterparty with a BB credit rating represented 12% of our total credit exposure, net of collateral.

Other. For additional information about price volatility and our hedging strategy, see "—Certain Factors Affecting Our Future Earnings—Factors Affecting the Results of Our Wholesale Energy Operations—Price Volatility," and "—Risks Associated with Our Hedging and Risk Management Activities."

For a description of accounting policies for our trading and marketing activities, see notes 2(d), 2(t) and 7 to our consolidated financial statements.

We seek to monitor and control our trading risk exposures through a variety of processes and committees. For additional information, see "Quantitative and Qualitative Disclosures About Market Risk—Risk Management Structure" in Item 7A of this Form 10-K/A.

Related-Party Transactions

In the normal course of operations, we have entered into transactions and agreements with related parties, including CenterPoint. For a discussion of historical related party transactions, see note 3 to our consolidated financial statements. Below are details of significant current related party transactions, arrangements and agreements.

Agreements With CenterPoint

Master Separation Agreement. Shortly before our IPO, we entered into a master separation agreement with CenterPoint. The agreement provided for the separation of our assets and businesses from those of CenterPoint. It also contains agreements governing the relationship between CenterPoint and us after our IPO, and in some cases after the Distribution, and specifies the related ancillary agreements that we have signed with CenterPoint, some of which are described in further detail below.

The agreement provides for cross-indemnities intended to place sole financial responsibility on us and our subsidiaries for all liabilities (except for certain possible tax liabilities) associated with the current and historical businesses and operations we conduct after giving effect to the separation, regardless of the time those liabilities arise, and to place sole financial responsibility for liabilities associated with CenterPoint's other businesses with CenterPoint and its other subsidiaries. Each party has also agreed to assume and be responsible for some specified liabilities associated with activities and operations of the other party and its subsidiaries to the extent performed for or on behalf of the other party's current or historical business.

The agreement also requires us to indemnify CenterPoint for any untrue statement of a material fact, or omission of a material fact necessary to make any statement not misleading, in the registration statement or prospectus that we filed with the SEC in connection with our IPO.

Texas Genco Option. In connection with the separation of our businesses from those of CenterPoint, CenterPoint granted us an option to purchase all of the shares of capital stock owned by CenterPoint in January 2004 of Texas Genco, which holds the Texas generating assets of CenterPoint's electric utility division. For additional information regarding the Texas Genco option and various agreements between CenterPoint and us related to the Texas Genco option, see note 4(b) to our consolidated financial statements.

Service Agreements. We have entered into agreements with CenterPoint under which CenterPoint will provide us, on an interim basis, various corporate support services, information technology services and other previously shared services such as corporate security, facilities management, accounts receivable, accounts payable, remittance processing and payroll, office support services and purchasing and logistics. The charges we will pay CenterPoint for these services are generally intended to allow CenterPoint to recover its fully allocated costs of providing the services, plus out-of-pocket costs and expenses. In addition, pursuant to lease agreements, CenterPoint will lease us office space in its headquarters building and various other locations in Houston, Texas for various terms. For additional information regarding these agreements, see note 4(a) to our consolidated financial statements.

Payment to CenterPoint. To the extent that our price to beat for electric service to residential and small commercial customers in CenterPoint's Houston service territory during 2002 and 2003 exceeds the market price of electricity, we may be required to make a significant payment to CenterPoint in 2004. As of December 31, 2002, our estimate for the payment related to residential customers is between $160 million and $190 million, with a most probable estimate of $175 million. For additional information regarding this payment, see note 14(e) to our consolidated financial statements.

Guarantee of Certain Benefit Payments. We have guaranteed, in the event CenterPoint becomes insolvent, certain non-qualified benefits of CenterPoint's and its subsidiaries' existing retirees at the Distribution totaling approximately $58 million.

Transportation Agreement. Prior to the IPO, Reliant Energy Services (our wholly-owned trading subsidiary) entered into an agreement whereby a subsidiary of CenterPoint agreed to reimburse Reliant Energy Services for any transportation payments made under a transportation agreement with ANR Pipeline Company and for the refund of $41 million due to ANR Pipeline Company, an unaffiliated company. For additional information regarding this transportation agreement, see note 14(f) to our consolidated financial statements.

Generating Capacity Auction Line of Credit. On October 1, 2002, our retail energy segment, through a subsidiary, entered into a master power purchasing contract with Texas Genco covering, among other things, our purchase of capacity and/or energy from Texas Genco's generating facilities. In connection with the March 2003 refinancing, this contract has been amended to grant Texas Genco a security interest in the accounts receivable and related assets of certain retail energy segment subsidiaries, the priority of which is subject to certain permitted prior financing arrangements, and the junior liens granted to the lenders under the March 2003 refinancing. In addition, many of the covenant restrictions contained in the contract were removed in the amendment.

Various Other Agreements. In connection with the separation of our businesses from those of CenterPoint, we have entered into other agreements providing for, among other things, mutual indemnities and releases with respect to our respective businesses and operations, matters relating to corporate governance, matters relating to responsibility for employee compensation and benefits, and the allocation of tax liabilities. In addition, we and CenterPoint have entered into various agreements relating to ongoing commercial arrangements including, among other things, the leasing of optical fiber and related maintenance activities, gas purchasing and agency matters, and subcontracting energy services under existing contracts. For additional information regarding these agreements, see notes 3 and 4 to our consolidated financial statements.

Risk Factors

Set forth below, elsewhere in the Form 10-K/A and in other documents we file with the SEC are risks and uncertainties that could cause our actual results to differ materially from the results contemplated by our forward-looking statements contained in the Form 10-K/A.

Risks Related to Our Retail Energy Operations

We may lose a significant number of our retail residential and small commercial customers in the Houston metropolitan area.

In June 1999, the Texas legislature adopted the Texas electric restructuring law, which substantially amended the regulatory structure governing electric utilities in Texas in order to allow full retail competition. Beginning in 2002, all classes of Texas customers of most investor-owned electric utilities, and those of any municipal utility and electric cooperative that opted to participate in the competitive marketplace, were able to choose their retail electric provider. In January 2002, we began to provide retail electric services to all customers of CenterPoint who did not take action to select another retail electric provider. As an affiliated retail electric provider, we are initially required to sell electricity to these Houston area residential and small commercial customers at a specified price, or price to beat, whereas other retail electric providers will be allowed to sell electricity to these customers at any price. We are not permitted to offer electricity to these customers at a price other than the price to beat until January 2005, unless before that date the PUCT determines that 40% or more of the amount of electric power that was consumed in 2000 by the relevant class of customers in the Houston metropolitan area is committed to be served by retail electric providers other than us. Because we are not able to compete for residential and small commercial customers on the basis of price in the Houston area, we may lose a significant number of these customers to other providers.

We may lose a significant portion of our market share of large commercial, industrial and institutional customers in Texas.

We are providing commodity services to the large commercial, industrial and institutional customers previously served by CenterPoint who did not take action to contract with another retail electric provider. In addition, we have signed contracts to provide electricity and energy efficiency services to large commercial, industrial and institutional customers, both in the Houston area, as well as in other parts of the ERCOT Region. We or any other retail electric provider can provide services to these customers at any negotiated price. The market for these customers is very competitive, and any of these customers that selects us to be their provider may subsequently decide to switch to another provider at the conclusion of the term of their contract with us.

The results of our retail electric operations in Texas are largely dependent upon the amount of headroom available in our price to beat. Future adjustments to the price to beat may be inadequate to cover our costs to purchase power to serve our residential and small commercial customers.

The results of our residential and small commercial retail electric operations in Texas are largely dependent upon the amount of headroom available in our price to beat. Headroom may be a positive or negative number. Our current price is based on a wholesale energy supply cost component, or "fuel factor," based on the ten trading-day average forward 12-month natural gas price of $4.956 per MMbtu. The PUCT's current regulations allow us to request an adjustment of our fuel factor based on the percentage change in the forward price of natural gas or as a result of changes in the price of purchased energy up to twice a year. In a purchased energy request, we may adjust the fuel factor to the extent necessary to restore the amount of headroom that existed at the time the initial price to beat fuel factor was set by the PUCT. We cannot estimate with any certainty the magnitude and frequency of the adjustments required, if any, and the eventual impact of such adjustments on the amount of headroom available in our price to beat. If this adjustment and any future adjustments to our price to beat are inadequate to cover future increases in our costs to purchase power to serve our price to beat customers or are delayed by the PUCT, our business, results of operations, financial condition and cash flows could be materially adversely affected. In March 2003, the PUCT approved a revised price to beat rule. The changes from the previous rule include an increase in the number of days used to calculate the natural gas price average from ten to 20, and an increase in the threshold of what constitutes a significant change in the market price of natural gas and purchased energy from 4% to 5%, except for filings made after November 15th of a given year that must meet a 10% threshold. The revised rule also provides that the PUCT will, after reaching a determination of stranded costs in 2004, make downward adjustments to the price to beat fuel factor if natural gas prices drop below the prices embedded in the then-current price to beat fuel factor. In addition, the revised rule also specifies that the base rate portion of the price to beat will be adjusted to account for changes in the non-bypassable rates that result from the utilities' final stranded cost determination in 2004. Adjustments to the price to beat will be made following the utilities' final stranded cost determination in 2004. At this time, we cannot predict the impact of the changes on our financial condition or results of operations.

We face strong competition from affiliated retail electric providers of incumbent electric utilities and other competitors.

In most retail electric markets outside the Houston area, our principal competitor is the local incumbent electric utility company's retail affiliate. These retail affiliates have the advantage of long-standing relationships with their customers. In addition to competition from the incumbent electric utilities' affiliates, we face competition from a number of other retail electric providers, including affiliates of other non-incumbent electric utilities, independent retail electric providers and, with respect to sales to large commercial, industrial and institutional customers, independent power producers and wholesale power providers acting as retail electric providers. Some of these competitors are larger and better capitalized than we are.

Our retail energy supply activity is subject to extensive market oversight. Changes to market protocols or new regulation could have a material adverse effect on our business, results of operations, financial condition and cash flows.

The ERCOT ISO, which oversees the ERCOT Region, has and may continue to modify the market structure and other market mechanisms in an attempt to improve market efficiency. Moreover, existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to our commercial activities. These actions could have a material adverse effect on our results of operations, financial condition and cash flows.

Payment defaults by other retail electric providers to ERCOT could have a material adverse effect on our business, results of operations, financial condition and cash flows.

In the event of a default by a retail electric provider of its payment obligations to ERCOT, the portion of the obligation that is unrecoverable by ERCOT from the defaulting retail electric provider is assumed by the remaining market participants in proportion to each participants load ratio share. As a retail electric provider and market participant in ERCOT, we would pay a portion of the amount owed to ERCOT should such a default occur, and ERCOT is not successful in recovering such amounts. The default of a retail electric provider in its obligations to ERCOT could have a material adverse effect on our business, results of operations, financial condition and cash flows.

In March 2003, TCE filed for bankruptcy protection. TCE has filed a request that the bankruptcy court pay pre-petition amounts owed to ERCOT. The bankruptcy court approved such request; however, no assurance can be given that TCE will be able to satisfy its obligations to ERCOT.

We are heavily dependant upon third party providers of capacity and energy to supply our retail obligations.

We do not own sufficient generating resources in Texas to supply our retail business. The capacity and energy to supply our retail business is purchased at market prices from a variety of suppliers under contracts with varying terms. Our retail customers are concentrated in the Houston metropolitan area and there is limited ability to serve these customers with generation located outside the Houston metropolitan area. Texas Genco, located in the Houston congestion zone, is the largest supplier of capacity and energy for our retail business and is likely to remain our largest supplier for the foreseeable future. There is a significant risk that our business, results of operations, financial condition and cash flows could be materially adversely affected if we are not able to purchase the capacity and energy from Texas Genco or otherwise obtain sufficient capacity and energy required to serve our customers. The failure of any of our third party suppliers to perform under the terms of existing or future contracts could have a material adverse effect on our results of operations, financial condition and cash flows.

We may be required to make a substantial payment to CenterPoint in 2004.

To the extent that our price to beat for electric service to residential and small commercial customers in CenterPoint's Houston service territory during 2002 and 2003 exceeds the market price of electricity, we may be required to make a significant payment to CenterPoint in 2004. As of December 31, 2002, our estimate for the payment related to residential customers is between $160 million and $190 million, with a most probable estimate of $175 million. For additional information regarding this payment, see note 14(e) to our consolidated financial statements.

We rely on the infrastructure of transmission and distribution utilities and the ERCOT ISO to transmit and deliver electricity to our retail customers and to obtain information about our retail customers. In addition, we rely on the reliability of our own infrastructure and systems to perform enrollment and billing functions. Any infrastructure failure could negatively impact our customers' satisfaction and could have a material negative impact on our earnings.

We are dependent on transmission and distribution utilities for maintenance of the infrastructure through which we deliver electricity to our retail customers. Any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact the satisfaction of our customers with our service and could have a material adverse effect on our results of operations, financial condition and cash flow. Additionally, we are dependent on the transmission and distribution utilities for performing service initiations and changes, and for reading our customers' energy meters. We are required to rely on the transmission and distribution utility or, in some cases, the ERCOT ISO, to provide us with our customers' information regarding energy usage, and we may be limited in our ability to confirm the accuracy of the information. The provision of inaccurate information or delayed provision of such information by the transmission and distribution utilities or the ERCOT ISO could have a material adverse effect on our business, results of operations, financial condition and cash flow. In addition, any operational problems with our new systems and processes could similarly have a material adverse effect on our business, results of operations, financial condition and cash flow. For additional information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Retail Energy" in Item 7 of this Form 10-K/A.

The ERCOT ISO has experienced a number of problems with its information systems since the advent of competition in the Texas market that have resulted in delays in switching customers and receiving final settlement information for customer accounts. While performance is improving, if these problems do not continue to improve, our operating results may be adversely affected.

The ERCOT ISO is the independent system operator responsible for maintaining reliable operations of the bulk electric power supply system in the ERCOT Region and for acting as a central agent for the registration of customers with their chosen retail electric supplier. Its responsibilities include ensuring that information relating to a customer's choice of retail electric provider, including data needed for on-going servicing of customer accounts, is conveyed in a timely manner to the appropriate parties. Problems in the flow of information between the ERCOT ISO, the transmission and distribution utilities and the retail electric providers have resulted in delays and other problems in enrolling and billing customers. While the flow of information has improved materially over the course of the first year of full market choice operations, remaining system and process problems are still being addressed. When customer enrollment transactions are not successfully processed by all involved parties, ownership records in the various systems supporting the market are not synchronized properly and subsequent transactions for billing and settlement are adversely affected. The impact can include us not being the electric provider-of-record for intended or agreed upon time periods, delays in receiving customer consumption data that is necessary for billing and settlement either through the ERCOT ISO or directly with transmission and distribution utilities, as well as the incorrect application of rates or prices and imbalances in our electricity supply forecast and actual sales.

The ERCOT ISO is also responsible for handling, scheduling and settlement for all electricity supply volumes in the ERCOT Region. The ERCOT ISO plays a vital role in the collection and dissemination of metering data from the transmission and distribution utilities to the retail electric providers. We and other retail electric providers schedule volumes based on forecasts, which are based, in part, on information supplied by the ERCOT ISO. For additional information regarding settlement issues, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Retail Energy" in Item 7 of this Form 10-K/A.

Risks Related to Our Wholesale Energy Operations

Our results of operations, financial condition and cash flows are subject to market risks, the impact of which we cannot fully mitigate.

As part of our merchant generation business, we sell electric energy, capacity and ancillary services and purchase fuel under short and long-term contractual obligations and through various spot markets. We are not guaranteed any rate of return on our capital investments through cost of service rates, and our results of operations, financial condition and cash flows from these businesses are subject to market risks, which can be partially mitigated by hedging long-term sales agreements and other management actions. However, a substantial portion of market risk remains beyond our control. These market risks include commodity price risk, counterparty, credit risk, transmission risk and competitor actions.

We rely on market liquidity and the establishment of valid pricing to properly manage our risks.

Our commercial businesses depend on sufficient market participation to establish market liquidity and valid pricing to properly manage the risks inherent in our businesses. A reduction in the number of market participants may impair our ability to manage business risks. In addition, such a reduction may increase our management's reliance on internal models for decision-making. Our internal models may not adequately represent the markets in which we participate, potentially causing us to make incorrect decisions. These factors could have a material adverse effect on our results of operations, financial condition and cash flows.

We may not be able to satisfy the guarantees and indemnification obligations relating to our commercial activities if they become due at the same time.

In connection with our commercial businesses, we guarantee or indemnify the performance of a significant portion of the obligations of certain of our subsidiaries. For example, we routinely guarantee the obligations of Reliant Energy Services and other subsidiaries under substantially all of their gas and electricity trading, marketing and origination contracts. In addition, we have, from time to time, executed guarantees of the obligations of our subsidiaries under leases of real property, financing documents and certain other miscellaneous contracts such as long-term turbine maintenance contracts. Some of these guarantees and indemnities are for fixed amounts, others have a fixed maximum amount and others do not specify a maximum amount. The obligations underlying these guarantees and indemnities are recorded on our consolidated balance sheet as price risk management liabilities. These obligations make up a significant portion of these line items. If we were unable to successfully negotiate lower amounts or alternative arrangements, we would not be able to satisfy all of these guarantees and indemnification obligations if they were to come due at the same time. For additional information regarding our guarantees and indemnification obligations, see note 14(g) to our consolidated financial statements.

We rely on power transmission and natural gas transportation facilities that we do not own or control. If these facilities fail to provide us with adequate transmission capacity, we may not be able to deliver our wholesale power to our customers or receive natural gas products at our facilities.

We depend on power transmission and distribution and natural gas transportation facilities owned and operated by utilities and others to deliver energy products to our customers. Our customers in turn either consume these products or deliver them to the ultimate consumer. If transmission or transportation is disrupted, or the capacity is inadequate, our ability to sell and deliver our products may be hindered.

Increasing competition in wholesale power markets may adversely affect our results of operations, financial condition, cash flows and may require additional liquidity to remain competitive .

Our wholesale energy segment competes with other energy merchants. In order to successfully compete, we must have the ability to aggregate supplies at competitive prices from different sources and locations and must be

able to efficiently utilize transportation services from third-party pipelines and transmission services from electric utilities. We also compete against other energy merchants on the basis of our relative skills, financial position and access to credit sources. Energy customers, wholesale energy suppliers and transporters often seek financial guarantees and other assurances that their energy contracts will be satisfied. If price information becomes increasingly available in the energy marketing and trading business, we anticipate that our operations will experience greater competition and downward pressure on per-unit profit margins. In addition, our merchant asset business is constrained by our liquidity, our access to credit and the reduction in market liquidity. Other companies with which we compete may not have similar constraints.

Our wholesale energy segment is subject to extensive market regulation. Changes in these regulations could have a material adverse effect on our business, results of operations, financial condition and cash flows.

The FERC, which has jurisdiction over wholesale power rates, as well as independent system operators that oversee some of these markets, has and may likely continue to impose price limitations, bidding rules and other mechanisms in an attempt to address some of the price volatility in these markets and mitigate market price fluctuations. These actions, along with potential changes to existing mechanisms, could have a materially adverse effect on our results of operations, financial condition and cash flows.

We operate in a regulatory environment that is undergoing significant changes as a result of varying restructuring initiatives at both the state and federal levels. New regulatory policies, which may have a significant impact on our industry, are now being developed and we cannot predict the future direction of these changes or the ultimate effect that this changing regulatory environment will have on our business.

Moreover, existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to our facilities or our commercial activities. Such future changes in laws and regulations may have a detrimental effect on our business. In this connection, state officials, the Cal ISO and the investor-owned utilities in California have argued to the FERC that our California generating subsidiaries should not continue to have market-based rate authority. While the FERC to date has consistently refused to force entities with market-based rates to return to cost-based rates, some of these proceedings are ongoing and we cannot predict what actions the FERC may take in the future. The impact of receiving cost-based rates on our California portfolio is also not predictable given that the numerous details of any such implementation are unknown at this time.

In addition to the FERC investigations, several state and other federal regulatory investigations are ongoing in connection with wholesale electricity prices to determine the causes of the high prices and potentially to recommend remedial action. As these investigations proceed, additional matters could be discovered that could result in the imposition of restrictions on our business, fines, penalties or other adverse actions.

The Cal ISO has undertaken, at the FERC's direction, a market redesign process that includes an ongoing obligation to offer available capacity in Cal ISO markets, a $250 per MWh price cap, as well as "automated" mitigation of all bids when any zonal clearing price for balancing energy exceeds $91.87 per MWh. The automated mitigation is only applied to bids that exceed certain reference prices and that would significantly increase the market price. However, in February 2003, the Cal ISO stated that it intends to appeal in federal court the FERC's decision regarding the application of automated mitigation to local market power situations. While the FERC has adopted similar thresholds for both local and system market power, Cal ISO is seeking to have a more restrictive procedure applied to local market power. Additional features of the California market redesign to be implemented in the future include a revised market monitoring and mitigation structure, a revised congestion management mechanism and an obligation for load-serving entities in California to maintain capacity reserves. A new California state statute purports to give the CPUC new power to regulate the operations and maintenance practices of our California generating subsidiaries, beyond the existing state regulation, regarding environmental and other health and safety matters. The CPUC has recently initiated the process of establishing the methods through which these new requirements will be administered.

The NY Market is subject to significant regulatory oversight and control. The results of our operations in the NY Market are dependent on the continuance of the current regulatory structure. The rules governing the current regulatory structure are subject to change. We cannot assure you that we will be able to adapt our business in a timely manner in response to any changes in the regulatory structure, which could have a material adverse effect on our financial condition, results of operations and cash flows. The primary regulatory risk in this market is associated with the oversight activity of the New York Public Service Commission, the NYISO and the FERC. Our assets located in New York are subject to "lightened regulation" by the New York Public Service Commission, including provisions of the New York Public Service Law that relate to enforcement, investigation, safety, reliability, system improvements, construction, excavation, and the issuance of securities. Because lightened regulation was accomplished administratively, it could be revoked. The NYISO has the ability to revise wholesale prices, which could lead to delayed or disputed collection of amounts due to us for sales of electric energy and ancillary services. The NYISO may in some cases, subject to the FERC approval, also impose cost-based pricing and/or price caps. The NYISO has implemented automated mitigation procedures under which day-ahead energy bids will be automatically reviewed. If bids exceed certain pre-established thresholds and have a significant impact on the market-clearing price, the bids are then reduced to a pre-established market-based or negotiated reference bid. The NYISO has also adopted, at the FERC's direction, more stringent mitigation measures for all generating facilities in transmission-constrained New York City.

The FERC has also undertaken a generic review of the terms and conditions of market-based rates for all sellers. Specifically, in November 2001, the FERC instituted an investigation regarding the tariffs of all sellers with market-based rate authority, including us. If the FERC adopts its proposed approach for addressing anti-competitive behavior, our future earnings may be adversely affected by an open-ended refund obligation on sales at market-based rates.

The FERC also instituted a SMD rulemaking proceeding that proposes to eliminate discrimination in transmission service and to standardize electricity market design. The FERC's SMD proceeding would establish standardized transmission service throughout the United States, a standard wholesale electric market design, including forward and spot markets for energy and an ancillary services market. Further, this proceeding is also expected to provide all RTOs specifications regarding the entities that administer these markets and how these entities perform market monitoring and mitigation. While SMD is a positive development for our business, significant opposition to SMD has been voiced, and we cannot predict at this time whether standard market design will be adopted as proposed or what effect standard market design would have on our business growth prospects and financial results.

The FERC's RTO initiative, which began in May 1999, is making progress in all areas of the country. If RTOs are established as envisioned by the FERC, "rate pancaking," or multiple transmission charges that apply to a single point-to-point delivery of energy will be eliminated within a region, and wholesale transactions within the region and between regions will be facilitated. The end result could be a more competitive, transparent market for the sale of energy and a more economic and efficient use and allocation of resources. However, considerable opposition exists in some regions of the United States to the development of RTOs as envisioned by the FERC, and the timing for completion of the developing RTOs is uncertain.

Additionally, federal legislative initiatives have been introduced and discussed to address the problems being experienced in some power markets and to enhance or limit the FERC authority. We cannot predict whether such proposals will be adopted or their impact on industry restructuring. If the trend towards competitive restructuring of the wholesale power markets is reversed, discontinued or delayed, the business growth prospects and financial results of our wholesale energy and retail energy segments could be adversely affected.

Our costs of compliance with environmental laws are significant and the cost of compliance with new environmental laws could adversely impact our profitability.

Our wholesale energy segment is subject to extensive environmental regulation by federal, state and local authorities. We are required to comply with numerous environmental laws and regulations, and to obtain

numerous governmental permits, in operating our facilities, a number of which are coal-fired and subject to particularly intense regulatory oversight. We may incur significant additional costs to comply with these requirements. If we fail to comply with these requirements, we could be subject to civil or criminal liability and fines. Existing environmental regulations could be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur, including potential regulatory and enforcement developments related to air emissions. If any of these events occur, our business, results of operations and financial condition and cash flows could be materially adversely affected. For more information regarding compliance with environmental laws, see "Business—Environmental Matters" in Item 1 of this Form 10-K/A.

The majority of our hydroelectric facilities are required to be licensed under the Federal Power Act. Any failure to obtain or maintain a required license for one or more of our hydroelectric facilities could have an adverse impact on us.

The Federal Power Act gives the FERC exclusive authority to license non-federal hydroelectric projects on navigable waterways and federal lands. The FERC hydroelectric licenses are issued for terms of 30 to 50 years. Some of our hydroelectric facilities, representing approximately 90 MW of capacity, have licenses that expire within the next ten years. Facilities that we own representing approximately 160 MW of capacity have new or initial license applications pending before the FERC. Upon expiration of a FERC license, the federal government can take over the project and compensate the licensee, or the FERC can issue a new license to either the existing licensee or a new licensee. In addition, upon license expiration, the FERC can decommission an operating project and even order that it be removed from the river at the owner's expense. In deciding whether to issue a license, the FERC gives equal consideration to a full range of licensing purposes related to the potential value of a stream or river. It is not uncommon for the relicensing process to take between four and ten years to complete. Generally, the relicensing process begins at least five years before the license expiration date and the FERC issues annual licenses to permit a hydroelectric facility to continue operations pending conclusion of the relicensing process. We expect that the FERC will issue to us new or initial hydroelectric licenses for all the facilities with pending applications. Presently, there are no applications for competing licenses and there is no indication that the FERC will decommission or order any of the projects to be removed.

As a result of events in California over the past few years, our wholesale power operations in our West region have experienced delays in the collection of receivables and are subject to uncertainty relating to ongoing litigation and governmental proceedings.

We are defendants in several class action lawsuits and other lawsuits filed against us and a number of other companies that either owned generation plants in California or sold electricity in California markets. These lawsuits challenge the prices for wholesale electricity in California during parts of 2000 and 2001. The FERC is also continuing its staff investigation into potential manipulation of electric and natural gas prices in the West region for the period from January 2000 to June 2001. Some counterparties have challenged long-term bilateral contracts based on the alleged market dysfunction in Western power markets in 2000 and 2001.

In addition to the FERC investigations, several state and other federal regulatory investigations are on-going in connection with the wholesale electricity prices in California and neighboring Western states to determine the causes of the high prices and potentially to recommend remedial action. Finally, a new California state statute purports to give the CPUC new powers to regulate the operations of our California generating subsidiaries, beyond the existing state regulation regarding environmental and other health and safety matters. The CPUC has recently initiated the process of establishing the methods through which these new requirements will be administered. For information regarding our receivables for sales in the California market and uncertainty relating to ongoing legal litigation and investigations, see notes 14(h) and 14(i) to our consolidated financial statements.

As these investigations proceed, additional matters could be discovered that could result in the imposition of restrictions on our businesses, fines, penalties or other adverse events.

Our business operations and hedging activities expose us to the risk of non-performance by counterparties.

Our trading, marketing and risk management services operations are exposed to the risk that counterparties who owe us money or physical commodities and services, such as power, natural gas or coal, will not perform their obligations. Should the counterparties to these arrangements fail to perform, we might be forced to acquire alternative hedging arrangements or replace the underlying commitment at then-current market prices. In this event, we might incur additional losses to the extent of amounts, if any, already paid to the counterparties.

As a result of recent events, including the credit crisis in the merchant energy sector, decreasing liquidity in our trading markets and the related downgrading of our credit ratings and the credit ratings of many of our trading counterparties to below investment grade, we have been required to enter into trading and other commercial arrangements with higher risk counterparties than those with whom we have typically contracted in the past. These arrangements, coupled with the credit crisis in our sector, have increased our exposure to the risk of non-performance by counterparties who owe us money or physical commodities.

Operation of power generation facilities involves significant risks that could negatively affect our results of operations and cash flows.

Our wholesale energy segment and our European energy segment are exposed to risks relating to the breakdown or failure of equipment or processes, fuel supply interruptions, shortages of equipment, material and labor, and operating performance below expected levels of output or efficiency. Significant portions of our facilities were constructed many years ago. Older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to add to or upgrade equipment to keep it operating at peak efficiency, to comply with changing environmental requirements, or to provide reliable operations. Such changes could affect our operating costs. Any unexpected failure to produce power, including failure caused by breakdown or forced outage, could have a material adverse effect on our results of operations, financial condition and cash flows.

Construction of power generation facilities involves significant schedule and cost risks that could negatively affect our results of operations, financial condition and cash flows.

Currently, we have four power generation facilities under development or construction. Our successful completion of these facilities is subject to the following:

- power prices;
- shortages and inconsistent qualities of equipment, material and labor;
- availability of financing;
- failure of key contractors and vendors to fulfill their obligations;
- work stoppages due to plant bankruptcies and contract labor disputes;
- permitting and other regulatory matters;
- unforeseen weather conditions;
- unforeseen equipment problems;
- environmental and geological conditions; and
- unanticipated capital cost increases.

Any of these factors could give rise to delays, cost overruns or the termination of the plant expansion or construction. Many of these risks cannot be adequately covered by insurance. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet specified performance standards, the proceeds of

such insurance, warranties or performance guarantees may not be adequate to cover lost revenues, increased expenses or liquidated damages payments we may owe.

If we were unable to complete the development of a facility, we would generally not be able to recover our investment in the project. The process for obtaining governmental permits and approvals is complicated, expensive, lengthy and subject to significant uncertainties. Transmission interconnection, fuel supply and cooling water arrangements represent some cost uncertainties during project development that may also result in termination of the project. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect our results of operations. The failure to complete construction according to specifications can result in liabilities, reduced plant efficiency, higher operating costs and reduced earnings.

The loss of the tolling agreement for our Liberty electric generating station could have a material adverse impact on our results of operations, financial condition and cash flows.

The output of our Liberty electric generating station is contracted under a long-term tolling agreement between LEP and PGET. We have several disputes with PGET that could result in the termination of the tolling agreement. If the tolling agreement is terminated, it is possible that Liberty's lenders would initiate foreclosure proceedings against LEP and Liberty and both Liberty and LEP may seek other alternatives, including reorganization under the bankruptcy laws. Such a termination may also result in PGET drawing on the $35 million letter of credit posted by Reliant Resources on behalf of LEP under the tolling agreement. For more information regarding this matter, see note 14(l) to our consolidated financial statements.

Risks Related to Our European Energy Operations

Increasing competition in the Dutch wholesale energy market may adversely affect our results of operations, financial condition and cash flows.

We expect over the long-run competition for energy customers in the markets in which our European energy segment operates to be high. The primary factors affecting our European energy segment's competitive position are price, regulation, the economic resources of its competitors, and its market reputation and perceived creditworthiness. Our European energy segment competes in the Dutch wholesale market against a variety of other companies, including other Dutch generation companies, cogenerators, various producers of alternate sources of power and non-Dutch generators of electric power, primarily from France and Germany. As of December 31, 2002, the Dutch electricity system had three operational interconnection points with Germany and two interconnection points with Belgium. There are also a number of projects that are at various stages of development and that may increase the number of interconnections in the future (post 2005), including interconnections with Norway and the United Kingdom. The Belgian interconnections are primarily used to import electricity from France, but a larger portion of Dutch electricity imports comes from Germany. It is anticipated that over time, transmission constraints between the Netherlands and other European markets will be reduced, thereby exposing our European energy segment to even greater competitive pressures. Competition among power generators for customers is intense and is expected to increase as more participants enter increasingly deregulated markets. Many of our European energy segment's existing competitors have geographic market positions far more extensive than that of our European energy segment. In addition, many of these competitors possess significantly greater financial, personnel and other resources than our European energy segment.

The timing and pace of the deregulation of other sectors of the European energy markets may have a material adverse effect on our business, results of operations, financial condition and cash flows.

Commercial markets in the Netherlands were generally opened to retail competition in January 2002. We expect the remainder of the market, consisting of mainly residential customers, will be open to competition by January 1, 2004. The timing of opening of the residential segment of the market is subject to change, however, at the discretion of the Dutch Minister of Economic Affairs. Since our European energy segment's operations focus

on the wholesale market, we do not expect that the opening of the Dutch commercial or residential electric market will have a significant impact on the segment's results of operations.

There is mark-to-market price risk exposure associated with our stranded cost gas supply contract.

The stranded cost gas supply contract is indexed to a combination of coal and inflation and has a foreign exchange exposure. A significant change in the contract index could have a material adverse effect on our results of operations, financial condition and cash flows. For additional information regarding this contract, see note 14(j) to our consolidated financial statements.

We have exposure to the disposition of certain contingent stranded cost liabilities pursuant to our ownership interest in NEA.

NEA entered into commitments with certain Norwegian counterparties for the construction of a grid interconnector cable between the Netherlands and Norway, subject to the operation of a long-term power exchange agreement (25 years in duration). For additional information regarding NEA, see note 14(j) to our consolidated financial statements.

Many of the risks related to our wholesale energy operations equally apply to our European energy operations.

Our European energy segment is subject to many of the same risks and uncertainties that confront our wholesale energy segment. In particular, our European energy segment is subject to similar market risks, hedging risks, non-performance by counterparties risks, transmission risks, environmental compliance risks, power generation risks, debt facility compliance risks and guarantee and indemnification risks related to our trading and marketing activities. For additional information concerning these risks and uncertainties, see "Risks Related to Our Wholesale Energy Operations."

Risks Related to Our Businesses Generally

We do not attempt to fully hedge our assets or positions against changes in commodity prices, and our risk management policies and procedures may not be effective.

Commodity price risk is an inherent component of our retail and wholesale energy operations. Our results of operations, financial condition and cash flows depend, in large part, upon prevailing market prices for electricity and fuel in our markets. Market prices may fluctuate substantially over relatively short periods of time, potentially adversely impacting our results of operations, financial condition and cash flows. Changes in market prices for electricity and fuel may result from the following:

- weather conditions;
- seasonality;
- demand for energy commodities and general economic conditions;
- forced or unscheduled plant outages;
- disruption of electricity or gas transmission or transportation, infrastructure or other constraints or inefficiencies;
- addition of generating capacity;
- availability of competitively priced alternative energy sources;
- availability and levels of storage and inventory for fuel stocks;
- natural gas, crude oil and refined products, and coal production levels;
- the creditworthiness or bankruptcy or other financial distress of market participants;

- changes in market liquidity;
- natural disasters, wars, embargoes, acts of terrorism and other catastrophic events; and
- federal, state and foreign governmental regulation and legislation.

To mitigate our financial exposure related to commodity price fluctuations, we routinely enter into contracts to hedge a portion of our purchase and sale commitments, exposure to weather fluctuations, fuel requirements and inventories of natural gas, coal, refined products, and other commodities and services. As part of this strategy, we routinely utilize derivative instruments (e.g., fixed-price forward physical purchase and sales contracts, futures, financial swaps and option contracts). However, we do not expect to cover the entire exposure of our assets or positions to market price and volatility changes, and the coverage will vary over time. This hedging activity fluctuates according to strategic objectives, taking into account the desire for cash flow or earnings certainty, the availability of liquidity resources and our view of market prices.

Our risk management procedures and our hedging strategies are constrained by our liquidity, our access to credit and the reduction in market liquidity, and may not be followed or work as planned. These and other factors may adversely impact our results of operations, financial condition and cash flows.

At times we have open positions in the market (required to be within established corporate risk management guidelines), resulting from optimizing our power generation portfolio and eliminating our remaining trading positions. If we have open positions, changes in commodity prices could negatively impact our results of operations, financial condition and cash flows. We have measures and controls in place that are designed to mitigate the impact of commodity price changes on our positions. These measures and controls are based on statistical analyses and estimates. Consequently, no assurance can be given that these controls and measures will be effective in the event that anomalous commodity price changes occur.

For additional information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Trading and Marketing Operations," "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K/A and note 7 to our consolidated financial statements.

The ultimate outcome of the numerous lawsuits and regulatory proceedings to which we are a party cannot be predicted at this time.

We are party to numerous lawsuits and regulatory proceedings relating to our trading and marketing activities, including the following:

- certain same-day commodity trading transactions in which we engaged in 1999, 2000 and 2001 involving purchases and sales with the same counterparty for the same volume at substantially the same price, referred to as "round trip trades;"
- a series of four structured transactions entered into during the period May 2001 through September 2001, referred to as "structured transactions;" and
- our activities in the California wholesale market from January 2000 to June 2001.

In addition, various state and federal governmental agencies have commenced investigations relating to these activities. These lawsuits, proceedings and investigations are currently the subject of intense, highly charged media and political attention. Their ultimate outcome cannot be predicted at this time. In addition, these lawsuits, proceedings and investigations could lead to the discovery of additional conduct or transactions not known at this time that could result in additional litigation or regulatory action. For additional information regarding these legal proceedings and investigations, see note 14(h) to our consolidated financial statements.

Our strategic plans may not be successful.

Our future results of operations are dependent on the success of our strategic plans. Our strategic plans with respect to our wholesale energy segment indicate a shift in emphasis from identifying and pursuing acquisition

and development candidates to completing facilities currently under construction and integrating recently acquired generation facilities. This change reflects our current focus on integrating the Orion Power assets with our other domestic wholesale energy operations, the completion of our construction projects and our judgments regarding the current state of the wholesale electricity and capital markets. Our strategy could change to respond to market conditions or other circumstances. Additionally, our strategic plans include the evaluation of our option to acquire 81% of Texas Genco from CenterPoint. Our decision will be based on many factors including the option price and our ability to finance this acquisition. Our inability to consummate the acquisition could adversely affect our future results of operations.

If we fail to obtain or maintain any necessary governmental permit or approval, our results of operations may be adversely affected.

Our operations are subject to complex and stringent energy, environmental and other governmental laws and regulations. The acquisition, ownership and operation of power generation facilities require numerous permits, approvals and certificates from federal, state and local governmental agencies. The operation of our generation facilities must also comply with environmental protection and other legislation and regulations. At present, we have wholesale operations in Arizona, California, Florida, Illinois, Maryland, Nevada, New Jersey, New York, Ohio, Pennsylvania, Texas and West Virginia. Most of our existing domestic generation facilities are exempt wholesale generators that sell electricity exclusively into the wholesale market. These facilities are subject to regulation by the FERC regarding rate matters and by state regulatory commissions regarding environmental and other health and safety matters. The FERC has authorized us to sell electricity produced from these facilities at market prices. The FERC retains the authority to modify or withdraw our market-based rate authority and to impose "cost of service" rates if it determines that market pricing is not in the public interest. Any reduction by the FERC of the rates we may receive for our generation activities may materially adversely effect our business, results of operations, financial condition and cash flows.

Changes in technology may impair the value of our power plants and may significantly impact our business in other ways as well.

Research and development activities are ongoing to improve alternative technologies to produce electricity, including fuel cells, microturbines and photovoltaic (solar) cells. It is possible that advances in these or other alternative technologies will reduce the costs of electricity production from these technologies to a level below that which we have forecasted. In addition, increased conservation efforts and advances in technology could reduce electricity demand and significantly reduce the value of our power generation assets. Changes in technology could also alter the channels through which retail electric customers buy electricity.

Our results of operations, our ability to access capital and insurance and our future growth prospects could be adversely affected by the occurrence or risk of occurrence of future terrorist attacks or related acts of war.

We are currently unable to measure the ultimate impact of the terrorist attacks of September 11, 2001 on our industry and the United States economy as a whole. The uncertainty associated with the military activity of the United States and other nations and the risk of future terrorist activity may impact our results of operations and financial condition in unpredictable ways. These actions could result in adverse changes in the insurance markets and disruptions of power and fuel markets. In addition, our generation facilities or the power transmission and distribution facilities on which we rely could be directly or indirectly harmed by future terrorist activity. The occurrence or risk of occurrence of future terrorist attacks or related acts of war could also adversely affect the United States economy. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues, margins and cash flows and limit our future growth prospects. The occurrence or risk of occurrence could also increase pressure to regulate or otherwise limit the prices charged for electricity or gas. Also, these risks could cause instability in the financial markets and adversely affect our ability to access capital on terms and conditions acceptable to us.

Our insurance coverage may not be sufficient and our insurance costs may increase.

We have insurance coverages, subject to various limits and deductibles, covering our generation facilities, including property damage insurance and general liability insurance in amounts that we consider appropriate. However, we cannot assure you that insurance coverage will be available in the future on commercially reasonable terms or that the insurance proceeds received for any loss of or any damage to any of our generation facilities will be sufficient to restore the loss or damage without negative impact on our financial condition and results of operations. The costs of our insurance coverage have increased significantly during recent periods and may continue to increase in the future.

The value of our foreign generating facilities and businesses may be reduced by risks related to laws of other countries, taxes, economic conditions, fluctuations in currency rates, political conditions, policies of foreign governments and labor supply and relations.

We have generation facilities in the Netherlands and trading operations in Northwest Europe. Operations outside the United States entail the following significant political and financial risks, which vary by country:

- changes in laws or regulations;
- changes in foreign tax and environmental laws and regulations;
- changes in United States laws, including tax laws, related to foreign operations;
- changes in general economic conditions affecting each country;
- fluctuations in inflation and currency exchange rates;
- changes in government policies or personnel; and
- changes in labor relations in operations outside the United States.

Our actual results may be affected by the occurrence of any of these events. The occurrence of any of these events could substantially reduce the value of the impacted generating facilities or businesses.

Risks Related to Our Corporate and Financial Structure

We have significant debt that could negatively impact our business.

We have significant debt outstanding. As of March 31, 2003, we had total consolidated debt outstanding of $8.6 billion. Our high level of debt could:

- make it difficult for us to satisfy our obligations;
- limit our ability to obtain additional financing to operate our business;
- limit our financial flexibility in planning for and reacting to industry changes;
- place us at a competitive disadvantage as compared to less leveraged companies;
- increase our vulnerability to general adverse economic and industry conditions, including changes in interest rates and volatility in commodity prices; and
- require us to dedicate a substantial portion of our cash flows to payments on our debt.

The incurrence of additional debt could make it more likely that we will experience some or all of the above-described risks. For more information regarding our outstanding debt, see notes 9 and 21(a) to our consolidated financial statements.

If we do not generate sufficient positive cash flows, we may be unable to service our debt.

Our ability to pay principal and interest on our debt depends on our future operating performance. Future operating performance is subject to market conditions and business factors that often are beyond our control. If our cash flows and capital resources are insufficient to allow us to make scheduled payments on our debt, we may have to reduce or delay capital expenditures, sell assets, seek additional capital or restructure or refinance our debt. We cannot assure you that the terms of our debt will allow these alternative measures or that such measures would satisfy our scheduled debt service obligations.

No assurance can be given that we will have sufficient cash flows to pay the principal, premium, if any, and interest on our debt. If we cannot make scheduled payments on our debt, we will be in default and, as a result:

- our debt holders could declare all outstanding principal and interest to be due and payable;
- our senior debt lenders could terminate their commitments and commence foreclosure proceedings against our assets; and
- we could be forced into bankruptcy or liquidation.

The terms of our debt may severely limit our ability to plan for or respond to changes in our businesses.

Our March 2003 credit facilities restrict our ability to take specific actions in planning for and responding to changes in our business without the consent of our lenders, even if such actions may be in our best interest. Our March 2003 credit facilities also require us to maintain specified financial ratios and meet specific financial tests. For more information regarding these restrictions, see "Management's Discussion and Analysis of Financial Condition and Result of Operations—Liquidity and Capital Resources—Consolidated Future Uses and Sources of Cash and Certain Factors Impacting Future Uses and Sources of Cash" in Item 7 of this Form 10-K/A and notes 9 and 21(a) to our consolidated financial statements.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in our being required to repay these borrowings before their due date. If we were unable to make this repayment or otherwise refinance these borrowings, our lenders could foreclose on our assets. If we were unable to refinance these borrowings on favorable terms, our businesses could be adversely impacted.

An increase in short-term interest rates could adversely affect our cash flows.

As of March 31, 2003, we had $7.8 billion of outstanding floating-rate debt. Because of capital constraints impacting our business at the time some of this floating-rate debt was entered into, the interest rate margins are substantially above our historical borrowing margins. In addition, any floating-rate debt issued by us in the future could be at interest rate margins substantially above our historical borrowing margins. While we may seek to use interest rate swaps or other derivative instruments to hedge portions of our floating-rate debt exposure, we may not be successful in obtaining hedges on acceptable terms. Any increase in short-term interest rates would result in higher interest costs and could adversely affect our results of operations, financial condition and cash flows.

Our non-investment grade credit ratings could adversely impact our ability to access capital on acceptable terms, optimize our assets and operate our risk management activities.

Our credit rating has been downgraded to below investment grade. The downgrading of our credit rating has limited, and will likely continue to limit, our ability to refinance our debt obligations and access the capital markets. A number of our commercial contracts and guarantees associated with our asset optimization and risk management operations require us to satisfy collateral margin requirements that vary depending on energy market prices and contract prices. In addition, certain of our contracts with commercial, industrial and institutional electricity customers give the customer the right to terminate the contract based on our receiving a below-investment-grade credit rating from certain ratings agencies. Through March 28, 2003, we have not

experienced any contract terminations in our retail energy segment as a result of downgrades of our credit ratings to below investment grade. As a result of the downgrading of our credit rating, we may not be able to satisfy future collateral margin requirements under these contracts and guarantees. For information regarding our current credit ratings by the major credit agencies and related future adverse impacts, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Consolidated Future Uses and Sources of Cash and Certain Factors Impacting Future Uses and Sources of Cash" in Item 7 of this Form 10-K/A.

Reliant Resources is a holding company with no operations of its own. As a result, we depend on distributions from our subsidiaries to make payments on our debt obligations and meet our other cash requirements. Applicable laws or contractual restrictions could limit the amount of distributions made to us by our subsidiaries.

We derive substantially all our operating income from, and hold substantially all of our assets through, our subsidiaries. As a result, we depend on distributions of cash flows and earnings of our subsidiaries in order to meet our payment obligations under our credit facilities and other obligations. These subsidiaries are separate and distinct legal entities and have no obligation, unless specifically contracted, to pay any amounts due on our debts or other obligations, whether by dividends, distributions, loans or otherwise. Many of our subsidiaries have guaranteed our obligations under our March 2003 credit facilities to the extent legally and contractually permitted and are co-borrowers under the new $300 million senior priority revolving credit facility. The terms of some of our subsidiaries' indebtedness restrict their ability to pay dividends or make payments to us in some circumstances. The terms of any new or amended subsidiary indebtedness could further restrict payments from these subsidiaries. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, could limit their ability to make payments or other distributions to us. For additional information regarding these restrictions, see notes 9 and 21(a) to our consolidated financial statements.

Our right to receive any assets of any subsidiary will be effectively subordinated to the claims of that subsidiary's creditors, including trade creditors. In addition, even if we are a creditor of any subsidiary, our rights as a creditor are subordinated to the indebtedness of the subsidiary under our March 2003 credit facilities.

Our historical financial results as a subsidiary of CenterPoint may not be representative of our results as a separate company.

The historical financial information relating to periods prior to the Distribution that we have included in this Form 10-K/A does not necessarily reflect what our results of operations, financial condition and cash flows would have been had we been a separate, stand-alone entity during such periods. Our costs and expenses during such periods reflect charges from CenterPoint for centralized corporate services and infrastructure costs. These allocations have been determined based on assumptions that we and CenterPoint considered to be reasonable under the circumstances. This historical financial information is not necessarily indicative of what our results of operations, financial condition and cash flows will be in the future. We may experience significant changes in our cost structure, funding and operations as a result of our separation from CenterPoint, including increased costs associated with reduced economies of scale, and increased costs associated with being a publicly traded, stand-alone company.

Risks Related to the Sale of Our European Energy Operations

We signed an agreement to sell our European energy operations to Nuon. As in any sale transaction with regulatory approval as a condition precedent, there is risk that the sale may be substantially delayed or may not be consummated.

In February 2003, we signed a share purchase agreement to sell our European energy operations to Nuon. The sale is subject to the approval of the Dutch and German competition authorities. We anticipate that the

consummation of the sale will occur in the summer of 2003. No assurance can be given that we will obtain the approval of the Dutch and German competition authorities or that such approvals can be obtained in a timely manner. For further information regarding the sale of our European energy operations, see notes 21(b) and 21(c) to our consolidated financial statements.

There is significant operational, commercial and financial risk to our European energy operations if the sale to Nuon is not consummated.

If the sale of our European energy operations is not consummated, we may be significantly impacted by negative market perception regarding an entity with a sub-investment grade credit rating, which has, directly and indirectly, three credit facilities that mature during 2003 with an aggregate face value of approximately $1.3 billion. Key commercial counterparties and vendors may limit their transactions and exposures with us. No assurance can be given regarding our ability to successfully or adequately mitigate these risks.

Liquidity and Capital Resources

Historical Cash Flows

The net cash provided by or used in operating, investing and financing activities for 2000, 2001 and 2002 is as follows:

	Year Ended December 31,		
	2000	2001	2002
	(in millions)		
Cash provided by (used in):			
Operating activities	$ 328	$ (127)	$ 611
Investing activities	(3,013)	(838)	(3,486)
Financing activities	2,721	1,000	3,981

Cash Provided by (Used in) Operating Activities

2002 Compared to 2001. Net cash provided by operating activities during 2002 increased $738 million compared to 2001. This increase was primarily due to $562 million of changes in working capital and other changes in assets and liabilities and to a lesser extent due to $176 million of changes from cash flows from operations, excluding changes in working capital and other changes in assets and liabilities.

Net cash provided by operating activities increased by $562 million from $825 million in net cash outflows in 2001 to $263 million in net cash outflows in 2002 due to changes in working capital and other changes in assets and liabilities due to the following:

- $95 million of net proceeds related to an arrangement with a financial institution to sell an undivided interest in accounts receivable from residential and small commercial retail electric customers (see note 15 to our consolidated financial statements);
- $136 million of net collateral deposits related to an operating lease returned to us in 2002 coupled with net collateral deposits paid in 2001 of $145 million (see note 14(c) to our consolidated financial statements);
- $79 million of reduced lease prepayments in 2002 compared to $181 million in 2001, related to the REMA sale-leaseback agreements (see note 14(a) to our consolidated financial statements);
- $121 million related to the settlement of two structured transactions in 2002 coupled with $117 million of related cash outflows due to the execution of the two structured transactions in 2001 (see note 7(b) to our consolidated financial statements);

- $145 million decrease in restricted cash resulting from Orion Power utilizing restricted cash to repay certain outstanding borrowings in connection with the restructuring of the Orion MidWest and Orion NY facilities in October 2002 (see note 9(a) to our consolidated financial statements);
- $200 million of cash proceeds received in 2002, excluding $2 million remaining in escrow, resulting from the settlement of the indemnification with former shareholders of REPGB of certain stranded costs contracts in December 2001 (see note 14(j) to our consolidated financial statements);
- $167 million decrease in restricted cash in 2002 coupled with increased restricted cash of $117 million in 2001 related to our REMA operations (see notes 2(l) and 14(a) to our consolidated financial statements); and
- $391 million decrease in net cash outflows due to a decrease in cash outflows associated with accounts payable of $950 million due to the timing of cash payments, offset by a net decrease in cash inflows associated with net intercompany accounts receivable of $66 million and with accounts receivable of $493 million primarily due to our retail energy segment beginning operations in 2002.

These items were partially offset by the following:

- a $100 million settlement payment made in 2002 related to certain stranded costs contracts (see note 14(j) to our consolidated financial statements);
- $125 million in net settlements of hedges of our net investment in foreign subsidiaries;
- $55 million loss settlement of forward-starting swaps during May and November of 2002;
- $220 million of cash outflows for margin deposits related to our trading and hedging activities primarily to provide credit support as a result of our downgrades to sub-investment grade coupled with cash inflows of $167 million for margin deposits in 2001; and
- other changes in working capital.

Net cash flows from operations, excluding changes in working capital and other changes in assets and liabilities increased $176 million in 2002 with net cash inflows of approximately $874 million in 2002, compared to $698 million in 2001, primarily due to the following:

- cash flows provided by our retail energy segment for retail sales during 2002 due to the Texas retail market opening to full competition in January 2002, partially offset by
- decreased operating cash flows from our wholesale energy segment primarily due to a $328 million decline in operating margins in 2002 compared to 2001.

2001 Compared to 2000. Net cash provided by operating activities during 2001 decreased by $455 million compared to 2000. This decrease was primarily due to changes of $779 million in working capital and other changes in assets and liabilities, offset by changes of $324 million from cash flows from operations excluding these items. Changes in working capital and other assets and liabilities in 2001 resulted in net cash outflows of approximately $825 million compared to $46 million in 2000, primarily due to the following:

- a $511 million net cash outflow due to a reduction in accounts payable partially offset by a reduction in accounts receivable and net intercompany accounts receivable during 2001 due to the timing of cash receipts and cash payments at our European energy segment and the payment of a significant gas payable by our wholesale energy segment in 2001 which was accrued in 2000;
- a $181 million lease prepayment related to the REMA sale-leaseback agreements (see note 14(a) to our consolidated financial statements);
- $117 million increase in restricted cash related to our REMA operations (see notes 2(l) and 14(a) to our consolidated financial statements);

- $145 million increase in deposits in a collateral account related to an equipment financing structure (see note 14(b) to our consolidated financial statements);
- $117 million of net cash outflows related to the execution of two structured transactions in 2001 (see note 7(b) to our consolidated financial statements); and
- the foregoing items were partially offset by $167 million of reduced net margin deposits on energy trading and hedging activities as a result of reduced commodity volatility and relative price levels of natural gas and power compared to the fourth quarter of 2000.

Cash flows from operations, excluding changes in working capital and other changes in assets and liabilities, were approximately $698 million in 2001 compared to approximately $374 million in 2000. This increase was primarily due to a $488 million increase in operating margins from our wholesale energy segment's power generation operations in 2001 compared to 2000. This increase was partially offset by increased costs related to our retail energy segment's increased staffing levels and preparation for competition in the retail electric market in Texas and reduced cash flows from our European energy segment primarily resulting from a decline in electric power generation margins as the Dutch electric market was completely opened to wholesale competition on January 1, 2001.

Cash Used in Investing Activities

2002 Compared to 2001. Net cash used in investing activities increased by $2.6 billion during 2002 compared to 2001. This increase was primarily due to funding the acquisition of Orion Power for $2.9 billion, partially offset by reduced capital expenditures of $179 million related to decreased construction of domestic power generation projects and capital expenditures by our retail energy segment related to acquiring and developing information technology systems during 2002 as compared to 2001 and a $137 million cash dividend received in 2002 from our European energy segment's equity investment in NEA (see note 8 to our consolidated financial statements).

2001 Compared to 2000. Net cash used in investing activities decreased by $2.2 billion during 2001 compared to 2000. This decrease was primarily due to the funding of the remaining purchase obligation for REPGB for $982 million on March 1, 2000, and the acquisition of REMA for $2.1 billion on May 12, 2000, partially offset by proceeds from the REMA sale leaseback transactions of $1.0 billion, each as more fully described below, partially offset by reduced capital expenditures of $93 million primarily by our wholesale energy segment partially offset by increased capital expenditures by our retail energy segment related to acquiring and developing information technology systems.

Acquisition of Orion Power Holdings, Inc. On February 19, 2002, we acquired all of the outstanding shares of common stock of Orion Power for an aggregate purchase price of $2.9 billion and assumed debt obligations of $2.4 billion. As of February 19, 2002, Orion Power's debt obligations were $2.4 billion ($2.1 billion net of restricted cash pursuant to debt covenants). We funded the purchase of Orion Power with a $2.9 billion credit facility and $41 million of cash on hand. For further discussion, see note 5(a) to our consolidated financial statements.

Acquisition of REMA and REMA Sale-Leaseback. On May 12, 2000, we completed the acquisition of REMA from Sithe Energies, Inc. for an aggregate purchase price of $2.1 billion. The acquisition was originally financed through bridge loans from CenterPoint, of which $1.0 billion was converted to equity. In August 2000, we entered into three separate sale-leaseback transactions with each of the three owner-lessors for our interests in three generating stations, which we acquired as part of the REMA acquisition. As consideration for the sale of our interest in the facilities, we received a total of $1.0 billion in cash that we used to repay indebtedness owed by us to CenterPoint. For additional information about the acquisition and these transactions, see notes 5(b) and 14(a) to our consolidated financial statements.

Acquisition of REPGB. On March 1, 2000, we funded the $982 million remaining REPGB purchase obligation. We obtained a portion of the funds for this purchase from a Euro 600 million ($596 million)

three-year term loan facility established in February 2000. For more information about the acquisition of REPGB, see note 5(c) to our consolidated financial statements.

Cash Provided by Financing Activities

2002 Compared to 2001. Cash flows provided by financing activities increased $3.0 billion in 2002 compared to 2001, primarily due to an increase in short-term borrowings used to fund the acquisition of Orion Power and other working capital requirements as well as to fund increased working capital in order to meet future obligations. In addition, we had decreased investments of excess cash in an affiliate of CenterPoint and decreases in purchases of treasury stock. These items were partially offset by $1.7 billion in net proceeds from our IPO in 2001 and $238 million increase in long-term debt repayments in 2002 compared to 2001.

2001 Compared to 2000. Cash flows provided by financing activities decreased by $1.7 billion in 2001 compared to 2000, primarily due to a decrease in borrowings from CenterPoint coupled with advancing excess cash on a short-term basis to a subsidiary of CenterPoint which provides a cash management function for CenterPoint, reduced contributions from CenterPoint, and a decrease in long-term borrowings and purchase of treasury stock during the second half of 2001. These items were partially offset by an increase in short-term borrowings from third parties, primarily used to fund the wholesale energy segment's capital expenditures and for general corporate purposes, and by $1.7 billion in net proceeds from the IPO.

Our Initial Public Offering. In May 2001, we offered 59.8 million shares of our common stock to the public at an IPO price of $30 per share and received net proceeds from the IPO of $1.7 billion. Pursuant to the terms of the master separation agreement with CenterPoint, we used $147 million of the net proceeds to repay certain indebtedness owed to CenterPoint. Proceeds not initially utilized from the IPO during 2001 were advanced on a short-term basis to CenterPoint, which provided a cash management function. As of December 31, 2001, we had $390 million of outstanding advances to CenterPoint. During 2001 and 2002, the IPO proceeds were used for repayment of third party borrowings, repurchase of our common stock, capital expenditures and payment of taxes, interest and other payables. In May 2001, prior to the closing of the IPO, CenterPoint converted to equity or contributed to us an aggregate of $1.7 billion of indebtedness owed by us to CenterPoint of which $35 million was related to accrued intercompany interest expense. Following the IPO, CenterPoint no longer provided financing or credit support for us, except for specified transactions or for a limited period of time. For additional information, see note 3 to our consolidated financial statements.

Orion Power's Subsidiaries Amended and Restated Credit Facilities. During October 2002, we terminated the Orion Power revolving senior credit facility and, as part of the same transaction, we refinanced the Orion MidWest credit facility and the Orion NY credit facility and extended their maturities until October 2005. In connection with this refinancing, we paid $145 million of outstanding borrowings under the related facilities. For further discussion regarding this refinancing, see note 9(a) to our consolidated financial statements.

Convertible Senior Notes. As of the Orion Power acquisition date, Orion Power had outstanding $200 million of aggregate principal amount of 4.5% convertible senior notes, due on June 1, 2008. Pursuant to certain change of control provisions, Orion Power commenced an offer to repurchase the convertible senior notes on March 1, 2002, which expired on April 10, 2002. During the second quarter of 2002, we repurchased $189 million in principal amount under the offer to repurchase. During the fourth quarter of 2002, the remaining $11 million aggregate principal amount of these notes were repurchased for $8 million. For additional information, see note 9(c) to our consolidated financial statements.

Treasury Stock Purchase. During 2001, we purchased 11 million shares of our common stock at an average price of $17.22 per share, for a $189 million aggregate purchase price. For additional information, see note 10(b) to our consolidated financial statements.

Consolidated Capital Requirements

Our liquidity and capital requirements are affected primarily by our results of operations, capital expenditures, debt service requirements, working capital needs and collateral requirements. We expect to complete the construction of new generation facilities that are in progress; however, the refinanced and new credit facilities entered into in March 2003 restrict the construction of any new generation facilities in the future. Subject to restrictions in our March 2003 credit facilities, maintenance of plants will continue to include costs necessary to operate the plants safely, including necessary environmental expenditures. We will evaluate opportunities to enter retail electric markets for large commercial, industrial and institutional customers, in particular, in regions in which we have electric generating facilities and capacity. Subject to restrictions in our March 2003 credit facilities, we may buy or acquire mass market customers in ERCOT. We expect our capital requirements to be met with cash flows from operations, borrowings under our senior secured revolving credit facility and proceeds from one or more debt and equity offerings, securitization of assets and other borrowings. We believe that our current level of cash and borrowing capability, along with our future anticipated cash flows from operations, will be sufficient to meet the existing operational and collateral needs of our business for the next 12 months. Subject to restrictions in our March 2003 credit facilities, if cash generated from operations is insufficient to satisfy our liquidity requirements, we may seek to sell assets, obtain additional credit facilities or other financings and/or issue additional equity or convertible instruments. For additional discussion regarding our capital commitments, see note 14(f) to our consolidated financial statements.

The following table sets forth our consolidated capital and operational and major maintenance expense requirements for 2002, and estimates of our consolidated capital and operational and major maintenance expense requirements for 2003 through 2007, excluding the purchase of Texas Genco (in millions):

	2002	2003	2004	2005	2006	2007
Retail energy	$ 33	$ 21	$ 21	$ 20	$ 20	$ 20
Wholesale energy (1)(2)	532	680	174	70	108	98
European energy (3)	19	34	11	16	56	16
Other operations	77	43	24	17	17	17
Major maintenance cash outlays	80	116	139	177	100	156
Total	$741	$894	$369	$300	$301	$307

(1) In connection with our separation from CenterPoint, CenterPoint granted us an option to purchase all of the shares of capital stock of Texas Genco owned by CenterPoint in January 2004. Texas Genco holds the Texas generating assets of CenterPoint's electric utility division. The purchase of Texas Genco has been excluded from the above table. For additional information regarding this option to purchase Texas Genco, see note 4(b) to our consolidated financial statements.

(2) We currently estimate the capital expenditures by off-balance sheet special purpose entities to be $349 million and $45 million in 2003 and 2004, respectively. Estimated capital expenditures for 2003 and 2004 for these projects have been included in the table above as we consolidated these special purpose entities effective January 1, 2003 upon the adoption of FIN No. 46. See note 14(b) to our consolidated financial statements for additional information regarding these transactions.

(3) In February 2003, we signed an agreement to sell our European energy operations. For further information, see "Consolidated Future Uses and Sources of Cash and Certain Factors Impacting Future Uses and Sources of Cash" within this section and note 21(b) to our consolidated financial statements.

Generating Projects. As of December 31, 2002, we had one generating facility under construction on our consolidated balance sheet. Total estimated cost of constructing this facility is $486 million. As of December 31, 2002, we had incurred $332 million of the total projected costs of this project, which was funded from equity and corporate debt. In addition to this generating facility, we are constructing three facilities under construction agency agreements through off-balance sheet special purpose entities to be completed in 2003 and 2004. As of December 31, 2002, the off-balance sheet special purpose entities had incurred $1.3 billion in construction costs, property, plant and equipment and spare parts inventory. We consolidated these special purpose entities effective January 1, 2003 upon the adoption of FIN No. 46. We expect to spend approximately an additional $420 million in order to complete these facilities. For more information regarding the construction agency agreements, see notes 2(t), 14(b) and 21(a) to our consolidated financial statements.

Environmental Expenditures. We anticipate spending up to $178 million in capital and other special project expenditures from 2003 through 2007 for environmental compliance, totaling approximately $36 million, $37 million, $16 million, $63 million and $26 million in 2003, 2004, 2005, 2006 and 2007, respectively, which is included in the above table. In addition, we expect to spend $30 million (which is not included in the table above) from 2003 through 2007 for pre-existing conditions and remediations, which are recorded as liabilities in our consolidated balance sheet.

Texas Genco Option. In connection with the separation of our businesses from those of CenterPoint, CenterPoint granted us an option to purchase all of the shares of capital stock of Texas Genco owned by CenterPoint in January 2004. If we exercise our purchase option, our March 2003 credit facilities would require us to fund the purchase obligation solely with proceeds from permitted asset sales, including our European energy operations, proceeds from subordinated debt and equity offerings, a limited recourse acquisition financing and/or borrowings at Texas Genco (or its intermediate holding company). If we are not able to realize such proceeds, we do not expect that we will be able to exercise the option. If we do not exercise the option, we will need to continue to contract with Texas Genco or others to meet some of our retail supply obligations. For additional information regarding this option to purchase CenterPoint's interest in Texas Genco, see note 4(b) to our consolidated financial statements.

The following table sets forth estimates to our consolidated contractual obligations as of December 31, 2002 to make future payments for 2003 through 2008 and thereafter:

Contractual Obligations	Total	2003	2004	2005	2006	2007	2008 and thereafter
				(in millions)			
Debt, including credit facilities	$ 7,356	$1,423	$ 170	$1,096	$ 515	$3,432	$ 720
Mid-Atlantic generating assets operating lease payments	1,424	77	84	75	64	65	1,059
Other operating lease payments	804	85	91	89	87	62	390
Trading and marketing liabilities	782	542	159	49	19	5	8
Non-trading derivative liabilities	658	343	138	40	24	13	100
Other commodity commitments	3,607	1,073	410	381	302	110	1,331
Payment to CenterPoint	175	—	175	—	—	—	—
Stadium naming rights	276	10	10	10	10	10	226
Other	5	5	—	—	—	—	—
Total contractual cash obligations	$15,087	$3,558	$1,237	$1,740	$1,021	$3,697	$3,834

For discussion of the refinancing of certain facilities in March 2003, the effects of which are reflected above, see note 21(a) to our consolidated financial statements and discussions below. During October 2005, the Orion MidWest and Orion NY credit facilities will mature. Included in the above table for debt contractual obligations in 2005 is $1.1 billion of Orion MidWest and Orion NY credit maturities. We believe that Orion MidWest's and Orion NY's future anticipated cash flows from operations will be sufficient to prepay a substantial portion of the outstanding borrowings under these credit facilities. Upon maturity of these facilities, we anticipate refinancing any remaining outstanding borrowings.

Mid-Atlantic Assets Lease Obligation. In August 2000, we entered into separate sale-leaseback transactions with each of the three owner-lessors for our applicable interests in three generating stations, which we acquired as part of the REMA acquisition. For additional discussion of these lease transactions, see notes 5(b) and 14(a) to our consolidated financial statements.

Other Operating Lease Commitments. For a discussion of other operating leases, see note 14(a) to our consolidated financial statements.

Other Commodity Commitments. For a discussion of other commodity commitments, see note 14(f) to our consolidated financial statements.

Payment to CenterPoint. To the extent that our price to beat for electric service to residential and small commercial customers in CenterPoint's Houston service territory during 2002 and 2003 exceeds the market price of electricity, we may be required to make a payment to CenterPoint in 2004. As of December 31, 2002, our estimate for the payment related to residential customers is between $160 million and $190 million, with a most probable estimate of $175 million. For additional information regarding this payment, see note 14(e) to our consolidated financial statements.

Naming Rights to Houston Sports Complex. In October 2000, we acquired the naming rights for a football stadium and other convention and entertainment facilities included in the stadium complex. Starting in 2002 and continuing through 2032, we pay $10 million each year for annual advertising under this agreement. For additional information on the naming rights agreement, see note 14(f) to our consolidated financial statements.

Consolidated Future Uses and Sources of Cash and Certain Factors Impacting Future Uses and Sources of Cash

During 2002, many factors negatively impacted us. These factors included weaker pricing for electric energy, capacity and ancillary services, coupled with a narrowing of the spark spread in the United States; market contraction, reduced volatility and reduced liquidity in the power trading markets in the United States and Northwest Europe; downgrades in our credit ratings to below investment grade by each of the major rating agencies; various legal and regulatory investigations and proceedings (see notes 14(h) and 14(i) to our consolidated financial statements); reduced market confidence in our financial reporting in light of our restatements and amendments; reduced access to capital and increased demands for collateral in connection with our trading, hedging and commercial obligations; the decline in market prices of our common stock; and continued weakness in the United States economy generally. Certain of these factors are discussed in more detail below.

Future acquisitions and development projects are restricted under our credit facilities. Although we are required to dedicate a substantial portion of our cash flows to payments on our debt, we currently expect to be able to complete the generation facilities currently under construction, as well as meet our currently anticipated capital expenditure and working capital needs without additional funding; however, we do have the ability to borrow additional funds, subject to certain restrictions in our March 2003 credit facilities, to fund our future capital expenditure and working capital needs.

We may need external financing to fund capital expenditures, including capital expenditures necessary to comply with air emission regulations or other regulatory requirements. If we are unable to obtain outside financing to meet our future capital requirements under restrictions in our March 2003 credit facilities or on terms that are acceptable to us, our financial condition and future results of operations could be materially adversely affected. In order to meet our future capital requirements, we may increase the proportion of debt in our overall capital structure (subject to restrictions in our credit facilities) or we may need to issue equity or convertible instruments, thereby diluting the interests of current shareholders. Increases in our debt levels may further adversely affect our credit ratings thereby further increasing the cost of our debt. In addition, the capital constraints currently impacting our industry may require additional future indebtedness to include terms and/or pricing that is more restrictive or burdensome than those of our current indebtedness and refinancings in March 2003. This may negatively impact our ability to operate our business, or severely restrict or prohibit distributions from our subsidiaries.

As a result of our March 2003 refinancing, our interest expense will increase substantially. The exact amount of the increase is difficult to estimate and will depend on a variety of factors, some of which are not within our control, such as prevailing interest rates. However, a comparison of the LIBOR interest rate margins

under our Orion acquisition term loan (which was included in our March 2003 refinancing) and our March 2003 senior secured term loans illustrates the possible magnitude of the interest expense increase. The interest rate margin over LIBOR was 2% for the Orion acquisition term loan and is 4% for the March 2003 senior secured term loans, equivalent to an interest expense difference of $20 million annually for each $1 billion of principal amount. For additional information concerning our March 2003 refinancing and the facilities that were refinanced, including applicable principal amounts and interest rates, see notes 9 and 21(a) to our consolidated financial statements.

Our March 2003 credit facilities are payable as follows:

Date	Payment required
Earlier of our acquisition of Texas Genco or December 15, 2004	Senior priority revolving credit facility must be repaid
May 15, 2006	$500 million of senior secured term loans must be repaid
March 15, 2007	Remaining senior secured term loans and senior secured revolving credit facility must be repaid

In addition, under our March 2003 credit facilities, certain warrants issued to our lenders would vest, and we would be required to pay our lenders certain fees, if we do not, on or before the dates set forth below, repay our senior secured term loans and/or permanently reduce the commitment under our senior secured revolving credit facility in the aggregate paydown/reduction amounts set forth below. The fees set forth below are a percentage of the unpaid senior secured term loans and the commitment in effect under the senior secured revolving credit facility, in each case as of the date indicated. The warrants set forth below are exercisable for shares of our common stock representing the indicated percentage of our outstanding common stock on a fully-diluted basis as of the closing of the refinancing (after giving effect to all warrants issued to our lenders on that date).

Date	Aggregate paydown/reduction	Fees	Warrants
March 31, 2003	—	—	2.5%(1)
May 14, 2004	$0.5 billion	0.50%	—
May 16, 2005	$1.0 billion	0.75%	2.0%(2)
May 15, 2006	$2.0 billion	1.00%	2.0%(2)

(1) These warrants vested upon closing of our March 2003 credit facilities.

(2) These warrants vest only if we fail to satisfy the indicated aggregate paydown/reduction amount on or before the indicated date.

The exercise prices of the warrants are based on average market prices of our common stock during specified periods in proximity to the paydown/reduction dates. The warrants are exercisable for a period of five years from the date they become vested.

Our ability to arrange debt and equity financing and our cost of capital are dependent on the following factors, without limitation:

- general economic and capital market conditions;
- acceptable credit ratings;
- credit availability and access to liquidity from banks and access to the capital markets;
- the success of our retail energy and wholesale energy segments' operations;
- investor, supplier and customer confidence in us, our competitors and peer companies and our wholesale power markets;
- market expectations regarding our future earnings and probable cash flows;
- market perceptions of our ability to access capital markets on reasonable terms;
- provisions of relevant tax and securities laws; and
- impact of lawsuits, investigations and other proceedings.

Our March 2003 credit facilities restrict our ability to take specific actions without the consent of our lenders, even if such actions may be in our best interest. Subject to certain exceptions, these restrictions limit our ability to, among other things:

- incur additional liens or make additional negative pledges on our assets;
- merge, consolidate or sell our assets;
- issue additional debt or engage in sale and leaseback transactions;
- pay dividends, repurchase capital stock or prepay other debt;
- make investments or acquisitions;
- engage in construction development activities in respect of power plants;
- enter into transactions with affiliates, except on an arm's length basis;
- make capital expenditures;
- materially change our business;
- amend our debt and other material agreements in certain respects;
- issue and sell capital stock; and
- engage in certain types of trading activities.

Credit Facilities.

As of December 31, 2002, we had $7.9 billion in committed credit facilities of which $315 million was unused. As of December 31, 2002, letters of credit outstanding under these facilities aggregated $677 million and borrowings aggregated $6.9 billion. As of December 31, 2002, $5.1 billion of our committed credit facilities were to expire by December 31, 2003. For a discussion of the refinancing and amendments of certain of these committed credit facilities in March 2003, see note 21(a) to our consolidated financial statements.

Currently, we are satisfying our capital requirements and other commitments primarily with cash from operations, cash on hand and borrowings available under our credit facilities. The following table summarizes our credit capacity and liquidity position at December 31, 2002.

	Total	Reliant Resources	Orion Power	European Energy(2)	Other
			(In millions)		
Total committed credit	$7,900	$4,508	$1,715	$1,244	$433
Outstanding borrowings	6,908	4,266	1,639	630	373
Outstanding letters of credit	677	235	31	373	38
Unused borrowing capacity	315	7	45	241	22
Cash and cash equivalents	1,227	657	7	112	451
Current restricted cash (1)	219	—	200	6	13
Total available liquidity	$1,761	$ 664	$ 252	$ 359	$486

(1) Current restricted cash includes cash at certain subsidiaries that is restricted by financing agreements, but is available to the applicable subsidiary to use to satisfy certain of its obligations.

(2) The results of our European energy segment are consolidated on a one-month lag basis.

Refinancings of Credit Facilities in March 2003.

During March 2003, we refinanced our (a) $1.6 billion senior revolving credit facilities (see note 9(a) to our consolidated financial statements), (b) $2.9 billion 364-day Orion acquisition term loan (see note 9(a) to our

consolidated financial statements), and (c) $1.425 billion construction agency financing commitment (see note 14(b) to our consolidated financial statements), and we obtained a new $300 million senior priority revolving credit facility. The refinancing combined the existing credit facilities into a $2.1 billion senior secured revolving credit facility, a $921 million senior secured term loan, and a $2.91 billion senior secured term loan. The refinanced credit facilities mature in March 2007. The $300 million senior priority revolving credit facility matures on the earlier of our acquisition of Texas Genco or December 15, 2004. For further discussion of this refinancing, see note 21(a) to our consolidated financial statements.

Restricted Cash.

All of our operations are conducted by our subsidiaries. Our cash flow and our ability to service parent-level indebtedness when due is dependent upon our receipt of cash dividends, distributions or other transfers from our subsidiaries. The terms of some of our subsidiaries' indebtedness restrict their ability to pay dividends or make restricted payments to us in some circumstances. For information regarding restricted cash and the related credit facilities, see notes 2(l) and 9(a) to our consolidated financial statements.

Credit Ratings.

As of April 2, 2003 our credit ratings for our senior unsecured debt are as follows:

Date Assigned	Rating Agency	Rating	Rating Description
November 25, 2002	Moody's	B3	Review for possible downgrade
April 2, 2003	Standard & Poor's (1)	B	CreditWatch Developing
April 1, 2003	Fitch	CCC+	Rating Watch Positive

(1) Standard & Poor's did not issue a credit rating on our senior unsecured debt; this credit rating is a corporate credit rating for Reliant Resources.

The credit ratings of our subsidiaries have been affected as well. As of April 2, 2003, the REMA lease certificates were rated B by Standard & Poor's and B3 by Moody's. The ratings remain on "CreditWatch Developing" and "review for possible downgrade", respectively. As of April 2, 2003, the RECE long-term issuer was rated B3 by Moody's. The rating remains on "review for possible downgrade." The Standard & Poor's corporate rating was B and remains on "CreditWatch Developing." As of April 2, 2003, the long-term issuer rating assigned by Moody's to REPGB was B1. The senior unsecured bank loan rating assigned by Standard & Poor's was B+ and remains on "CreditWatch Positive." As of April 2, 2003, the Moody's senior unsecured debt rating for Orion Power was B3. The rating remains on "review for possible downgrade." Standard & Poor's senior unsecured debt and corporate ratings for Orion Power were CCC+ and B, respectively. These ratings remain on "CreditWatch Developing."

We cannot assure you that these ratings will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell or hold our securities and may be revised or withdrawn at any time by the rating agencies. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to access capital on acceptable terms.

We have been adversely impacted by our previous downgrade to sub-investment grade in connection with certain commercial agreements and certain bank facilities. The commercial arrangements primarily include: (a) commercial contracts and/or guarantees related to our wholesale and retail trading, marketing, risk management and hedging activities and (b) surety bonds and contractual obligations related to the development and construction or refurbishment of power plants and related facilities. Certain bank facilities contain provisions whereby our interest rate margins are affected by our credit ratings. Due to the various downgrades, we have incurred additional interest expense.

In most cases, the consequences of rating downgrades are limited to the requirement by our counterparties that we provide credit support to them in the form of a pledge of cash collateral, a letter of credit or other similar credit support. In addition, certain of our retail electricity contracts with large commercial, industrial and institutional customers in the retail energy segment permit the customers to terminate their contracts once our unsecured debt ratings fall below investment grade or if our ratings are withdrawn entirely by a rating agency. As of March 20, 2003, no retail contracts have been terminated pursuant to these terms. In light of the credit rating downgrades, we are working with our various commercial counterparties to minimize the disruption to our normal commercial activities and to reduce the magnitude of the collateral we must post in support of our obligations to such counterparties.

In connection with our domestic commercial operations, as of March 20, 2003, we have posted cash collateral of $500 million and letters of credit of $286 million from Reliant Resources' facilities. Of these letters of credit, $134 million are drawn on a cash-secured, revolving letter of credit facility initiated on January 29, 2003, see note 21(f) to our consolidated financial statements. In addition, we have posted cash collateral related to commercial operations of $4 million and letters of credit of $30 million from Orion Power subsidiary facilities. We have also posted $371 million of letters of credit from subsidiary facilities in connection with the support of financings. Based on current commodity prices, we estimate that as of March 20, 2003, we could be required to post additional collateral of up to $222 million related to our domestic operations. This estimate could increase based on changes to commodity prices. Factors which could lead to an increase in our actual posting of collateral include adverse changes in our industry or negative reactions to additional credit rating downgrades or the secured nature of the refinancing of our debt facilities.

For our European operations, as of March 20, 2003, we have posted cash collateral and letters of credit in the amount of $49 million and $55 million, respectively, to support commercial operations. Of these letters of credit, $37 million are drawn under uncommitted banking arrangements. Additionally, we have posted letters of credit of $363 million under a separate facility to support cross border lease transactions. Based on current commodity prices, we estimate that as of March 20, 2003, we could be required to post additional collateral of up to $7 million related to our European operations. This estimate could increase based on changes to commodity prices. Factors which could lead to an increase in our actual posting of collateral include adverse changes in our industry or negative reactions to additional credit rating downgrades or the secured nature of the refinancing of our debt facilities. As of March 20, 2003, we had $86 million in unrestricted available cash and cash equivalents and $178 million available under committed European facilities to support European operations. These amounts are currently available to meet working capital needs and possible future requirements for credit support related to our European commercial obligations.

We believe that our current level of cash and borrowing capability, along with our future anticipated cash flows from operations, will be sufficient to meet the liquidity needs of our business for the next twelve months. Under certain unfavorable commodity price scenarios, however, it is possible that we could experience inadequate liquidity.

In addition, we have been involved in certain commercial activities (including long-term sales of electric energy or capacity from our generating facilities) that prospectively may not be feasible due to our current credit and liquidity situation, among other factors. The credit downgrades have also resulted in more limited access to credit worthy counterparties with which to transact and the need to make commercial concessions with counterparties as an inducement for them to do business with us. Given these factors, we had reduced the level of our trading, marketing and hedging activities, which will result in a potential reduction and greater volatility in future earnings.

In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions.

It is likely that, in order to exercise the Texas Genco option as permitted under our credit facilities, we may sell some of our assets. We have identified certain non-strategic generating assets for potential sale. To date, we have not reached an agreement to dispose of any significant assets nor have we included or assumed any

proceeds from asset sales in our current liquidity plan, other than the sale of our European energy operations (see note 21(b) to our consolidated financial statements). Due to unfavorable market conditions in the wholesale power markets, there can be no assurance that we will be successful in disposing of domestic generating assets at reasonable prices or on a timely basis.

Other Sources and Uses of Cash and Factors Impacting Cash.

Sale of our European Energy Operations. In February 2003, we signed a purchase agreement to sell our European energy operations to Nuon, a Netherlands-based electricity distributor. Upon consummation of the sale, we expect to receive cash proceeds from the sale of approximately $1.2 billion (Euro 1.1 billion). We intend to use the cash proceeds from the sale first to prepay the Euro 600 million bank term loan borrowed by Reliant Energy Capital (Europe), Inc. to finance a portion of the acquisition costs of our European energy operations. The maturity date of the credit facility, which originally was scheduled to mature in March 2003, has been extended (see notes 9(a) and 21(c) to our consolidated financial statements). We intend to use the remaining cash proceeds of approximately $0.5 billion (Euro 0.5 billion) to partially fund our option to acquire Texas Genco in 2004 (see note 4(b) to our consolidated financial statements). However, if we do not exercise the option, we will use the remaining cash proceeds to prepay debt. Certain approvals are needed for the sale to occur. No assurance can be given that we will obtain the necessary approvals or that they can be obtained in a timely manner. For further discussion of the sale, see note 21(b) to our consolidated financial statements.

Generating Capacity Auction Line of Credit. On October 1, 2002, our retail energy segment, through a subsidiary, entered into a master power purchasing contract with Texas Genco covering, among other things, our purchases of capacity and/or energy from Texas Genco's generating facilities. In connection with the March 2003 refinancing, this contract has been amended to grant Texas Genco a security interest in the accounts receivable and related assets of certain retail energy segment subsidiaries, the priority of which is subject to certain permitted prior financing arrangements, and the junior liens granted to the lenders under the March 2003 refinancing. In addition, many of the covenant restrictions contained in the contract were removed in the amendment.

California Trade Receivables and the FERC Refunds. As of December 31, 2002, we were owed a total receivable, including interest, of $120 million (net of estimated refund provision) by the Cal ISO, the Cal PX, the CDWR and California Energy Resources Scheduling for energy sales in the California wholesale market during the fourth quarter of 2000 through December 31, 2002. As of December 31, 2002, we had a $6 million pre-tax credit provision against these receivable balances. From January 1, 2003 through March 31, 2003, we have collected $7 million of these receivable balances. For additional information regarding these receivables and uncertainties in the California wholesale market, see notes 14(h) and 14(i) to our consolidated financial statements.

During 2002, we recorded $176 million in reserves for potential refunds owed by us, which excludes the $14 million settlement reached with the FERC in January 2003 relating to two days of trading in 2000 (see note 14(h) to our consolidated financial statements). Our inception-to-date reserve for such refunds totals $191 million as of December 31, 2002. We estimate the range of our refund obligations for California energy sales to be approximately $191 million to $240 million (excluding the $14 million refund related to the FERC settlement in January 2003). For additional information regarding the FERC refunds, see note 14(i) to our consolidated financial statements.

Counterparty Credit Risk. For a discussion of our counterparty credit risk, see "Management's Discussion and Analysis of Financial Conditions and Results of Operations—Trading and Marketing Operations."

Receivables Facility Covenant Violation. For discussion of a covenant violation under the receivables facility, see note 15 to our consolidated financial statements.

Liberty Electric Generating Station Contingency. The output of the Liberty Station is contracted under a tolling agreement between Liberty Electric Power, LLC, a wholly-owned indirect subsidiary of Orion Power, and

PG&E Energy Trading-Power, LP for a term of approximately 14 years, with an option to extend at the end of the term. For information regarding this tolling agreement, issues related to the financing of the Liberty Station and other related contingencies, including foreclosure concerns, see note 14(l) to our consolidated financial statements.

Reliant Energy Desert Basin Contingency. REDB sells capacity to Salt River Project under a long-term power purchase agreement. We guarantee certain of REDB's obligations under the power purchase agreement. As a result of our credit downgrade to below investment grade by two major ratings agencies, Salt River Project has requested performance assurance in the form of cash or a letter of credit from REDB under the power purchase agreement and from Reliant Resources under the guarantee. Under the power purchase agreement and guarantee, the total amount of performance assurance cannot exceed $150 million. For information regarding REDB's obligations, our related guarantee and other related contingencies, see note 14(k) to our consolidated financial statements.

Other Items. For other items that may affect our future cash flows from operations, see "—Risk Factors."

Off-Balance Sheet Transactions

Construction Agency Agreements and Equipment Financing Structure. In 2001, we, through several of our subsidiaries, entered into operative documents with special purpose entities to facilitate the development, construction, financing and leasing of three power generation projects. As of December 31, 2002, we did not consolidate the results of the special purpose entities in our consolidated financial statements. Effective January 1, 2003, upon the adoption of FIN No. 46, we began consolidating these special purpose entities. For information regarding these transactions and the refinancing in March 2003, see notes 14(b) and 21(a) to our consolidated financial statements.

Receivables Facility Agreement. In July 2002, we entered into a receivables facility arrangement with a financial institution to sell an undivided interest in accounts receivable from residential and small commercial retail electric customers under which, on an ongoing basis, the financial institution will invest a maximum of $125 million for its interest in such receivables. Pursuant to this receivables facility, we formed a QSPE as a bankruptcy remote subsidiary. For additional information regarding this transaction, see note 15 to our consolidated financial statements.

REMA Sales/Leaseback Transactions. In August 2000, we entered into separate sale/leaseback transactions with each of the three owner-lessors for our interests in three generating stations acquired in the REMA acquisition. For additional discussion of these lease transactions, see note 14(a) to our consolidated financial statements.

New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates

New Accounting Pronouncements

For discussion regarding new accounting pronouncements that impact us, see note 2(t) to our consolidated financial statements.

Significant Accounting Policies

For discussion regarding our significant accounting policies, see note 2 to our consolidated financial statements.

Critical Accounting Estimates

Our consolidated financial statements have been prepared in accordance with GAAP. The preparation of these financial statements requires that we make estimates and judgments that affect the reported amounts of

assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities at the date of our financial statements. Estimates and assumptions about future events and their effects cannot be perceived with certainty. On an on-going basis, we evaluate our estimates based on historical experience, current market conditions and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Nevertheless, actual results may differ from these estimates under different assumptions or conditions.

A critical accounting estimate is (a) one that requires assumptions that are highly uncertain at the time the estimate is made and (b) one in which different estimates could have reasonably been used in the current period, or changes in the accounting estimate that are reasonably likely to occur, which would have a material impact on the presentation of our financial condition or results of operations. Our estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. We believe our critical accounting estimates are limited to those described below. Our senior management has discussed the development and selection of the estimate of each of our critical accounting estimates with our audit committee of the board of directors. For a detailed discussion on the application of these and other accounting estimates, see Item 8. "Financial Statements and Supplementary Data, Note 1—Summary of Significant Accounting Policies." For each of our critical accounting estimates, we describe the following:

- the underlying estimate, including the methodology used, assumptions, and reasonably likely changes;
- the significance of the estimate to our financial condition and results of operations;
- how changes in the accounting estimate or the assumptions underlying it would affect our financial information; and
- certain historical changes in our estimates.

California Receivables Realizability and Refund Methodologies.

In response to the filing of a number of complaints challenging the level of wholesale prices in California, the FERC initiated a staff investigation and issued a number of orders implementing a series of wholesale market reforms. In these orders, the FERC also instituted a refund proceeding. The FERC issued an order on March 26, 2003, adopting in most respects the proposed findings of the presiding administrative law judge that had been issued in December 2002 following a hearing to apply the refund formula. The most consequential change involved the adoption of a different methodology for determining the gas price component of the refund formula. Instead of using California gas indices, the FERC ordered the use of a proxy gas price based on producing area price indices plus the posted transportation costs. In addition, the order allows generators to petition for a reduction of the refund calculation upon a submittal to the FERC of their actual gas costs and subsequent FERC approval. Based on the proposed findings of the administrative law judge, discussed above, adjusted for the March 2003 FERC order decision to revise the methodology for determining the gas price component of the formula, we estimate our refund obligation to be between \$191 million and \$240 million for energy sales in California (excluding the \$14 million refund related to the FERC settlement in January 2003, as discussed in note 14(h) to our consolidated financial statements). The low range of our estimate is based on a refund calculation factoring in a reduction in the total FERC refund based on the actual cost paid for gas over the proposed proxy gas price. The high range of our estimate of the refund obligation assumes that the refund obligation is not adjusted for the actual cost paid for gas over the proposed proxy gas price. Our estimate of the range will be revised further following responsive submissions to FERC and subsequent FERC orders. We cannot currently predict whether that will result in an increase or decrease in our high and low points in the range. As of December 31, 2001, we had a pre-tax credit provision of \$68 million against receivable balances related to energy sales in the California market. As of December 31, 2002, we had a remaining pre-tax credit provision of \$6 million against these receivable balances. For further discussion of our provisions and reserves, see note 14(i) to our consolidated financial statements.

Goodwill and Other Intangibles.

We periodically evaluate goodwill and other intangible assets for impairment when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The test is required to be performed at least annually.

We estimate the fair value of our reporting units using a combination of approaches, including an income approach based on internal plans, a market approach based on transactions in the marketplace for comparable types of assets, and a comparable public company approach. The income approach used in our analysis is a discounted cash flow analysis based on our internal plans and contains numerous assumptions made by management, any number of which if changed could significantly affect the outcome of the analysis. We believe that the income approach is the most subjective of the approaches.

The internal cash flow analyses used in our impairment analysis range over a period of ten to 15 years with an assumed terminal value for the value of our operations at the end of the analysis of an EBITDA multiple of primarily 6 to 7.5. For our annual impairment test as of November 1, 2002, these after-tax cash flows (excluding interest) were discounted back to the date of the analysis at an appropriate risk-adjusted discount rate of primarily 9% in order to determine the fair value of the reporting unit under the income approach. The income approach is weighted along with the other two approaches to determine the fair value of the reporting unit.

As part of our planning process we model all of the power generation facilities in the regions in which we operate in addition to those operated by us. Our internal analyses for our wholesale energy segment assume that there will be increased demand for electricity in the regions in which we operate, the markets in which we operate will continue to be deregulated, and that electricity margins and prices will recover to a level sufficient to make it profitable for companies like ours to build new generating facilities. Our analyses assume that the demand for power will rise at an annual rate of approximately 2% over the next several years. This growth over time is assumed to result in decreased reserve margins in the areas where we operate. As reserve margins decrease, it is our assumption that power generation margins will rise substantially over time to a level sufficient to attract new capacity (estimated to be in 2007 and 2008). We assume that this level of prices will be such that companies will build new generation facilities and these new facilities will be able to cover all of their operating expenses and yield an internal rate of return on their investment of 9%. This assumed rate of return is consistent with our risk-adjusted discount rate used in our analyses.

Over the past year, margins on the sales of electricity in our industry have decreased substantially. If the assumed recovery in future margins does not materialize as projected, we could be required to recognize an impairment depending on the determination of the fair market value of our wholesale energy segment's assets and liabilities.

Property, Plant and Equipment.

We periodically evaluate our property, plant and equipment when events and circumstances indicate that the carrying value of these assets may not be recoverable. Accounting standards require that if the sum of the undiscounted expected future cash flows from our assets (without interest charges that will be recognized as expenses when incurred) is less than the carrying value of the asset, an asset impairment must be recognized in the consolidated financial statements. The amount of impairment recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset. Assumptions and estimates used in our impairment analyses are consistent with assumptions and estimates used in our goodwill impairment analysis. See "Goodwill and Other Intangibles" within this section for further discussion of estimates and assumptions used in our impairment analyses.

During 2002, certain indicators for impairment existed with respect to steam and combustion turbines and two heat recovery steam generators that we purchased in September 2002. Based on our analysis, we determined this equipment was impaired and accordingly recognized a $37 million pre-tax impairment loss. For additional information regarding this impairment, see note 14(c) to our consolidated financial statements.

In December 2002, we evaluated the Liberty generation station and the related tolling agreement for impairment. There were no impairments based on our analyses. However, in the future we could incur a pre-tax loss of an amount up to our recorded net book value. For information regarding issues and contingencies related to our Liberty power generation station and the related tolling agreement, see note 14(l) to our consolidated financial statements.

Depreciation Expense.

We have a significant investment in power generation facilities. Approximately 85% of our total gross property, plant and equipment are electric generating facilities and equipment. Depreciation is computed using the straight-line method based on estimated useful lives. For a description of our accounting policies for property, plant and equipment and depreciation expense, see note 2(f) to our consolidated financial statements.

For power generation facilities and equipment acquired in acquisitions, third party expert appraisers and internal engineers are used to determine the estimated useful lives of these assets. Such determination is made through an assessment of the condition of the acquired power generation facilities and equipment, a review of projected maintenance, and a study of future cash flows. We utilize the weighted average life of the components of a power generation unit as the estimated useful life of each generation unit of a facility. The estimated useful lives are impacted by the condition of the acquired facilities, the fuel type of the generation facilities and future environmental requirements, among other factors.

For our developed power generation facilities, we utilize the specified design life that is provided in the engineering, procurement and construction contract. In the absence of a specified design life in the engineering, procurement and construction contract, we obtain an estimate of the weighted average life of the components of a power generation unit of a facility from our in-house engineers.

The computation of depreciation expense requires judgment regarding the estimated useful lives of property, plant and equipment. As circumstances warrant, the estimated useful lives of property, plant and equipment are reviewed to determine if any changes are needed. Such changes could involve an increase or decrease in the estimated useful lives, which would impact future depreciation expense.

Our power generation facilities are exposed to risks relating to the breakdown or failure of equipment or processes. Significant portions of our facilities were constructed many years ago. Older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to add to or upgrade equipment to keep it operating at peak efficiency, to comply with changing environmental requirements, or to provide reliable operations. Such items could impact the useful life of our power generation facilities. In addition, research and development activities are ongoing to improve alternative technologies to produce electricity, including fuel cells, microturbines and photovoltaic (solar) cells. It is possible that advances in these or other alternative technologies could reduce the costs of electricity production to a level below that which we have forecasted and accordingly make portions of our power generation facilities' useful lives decrease.

Trading and Marketing Assets and Liabilities.

Trading and marketing activities include (a) transactions establishing open positions in the energy markets, primarily on a short-term basis, (b) transactions intended to optimize our power generation portfolio, but which do not qualify for hedge accounting and (c) energy price risk management services to customers primarily related to natural gas, electric power and other energy-related commodities. We provide these services by utilizing a variety of derivative instruments (trading energy derivatives). We account for these transactions under mark-to-market accounting; for information regarding mark-to-market accounting, see notes 2(t) and 7 to our consolidated financial statements. Specifically, these trading and marketing activities consist of the following:

- the large contracted commercial, industrial and institutional customers under retail electricity contracts and the related energy supply contracts of our retail energy segment entered into prior to October 25, 2002;
- the domestic energy trading, marketing, risk management services to our customers and certain power origination activities of our wholesale energy segment; and
- the European energy trading and origination operations of our European energy segment.

Under the mark-to-market method of accounting, derivative instruments and contractual commitments are recorded at fair value in revenues upon contract execution. The net changes in their fair values are recognized in the statements of consolidated operations as revenues in the period of change. The recognized, unrealized balances are recorded as trading and marketing assets/liabilities in the consolidated balance sheets.

We value our trading and marketing assets and liabilities based on (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods. For further discussion of these various valuation techniques and the types of contracts included within each, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Trading and Marketing Operations" within Item 7 of this Form 10-K/A. Our pricing methodologies based on models and other valuation methods include, but are not limited to, extrapolation of forward pricing curves using historically reported data from illiquid pricing points. These same pricing techniques are used to evaluate a contract prior to taking a position. Other factors affecting our estimates of fair values include valuation adjustments relating to time value, the volatility of the underlying commitment, the cost of administering future obligations under existing contracts, and the credit risk of counterparties. Volatility valuation adjustments are calculated by utilizing observed market price volatility and represent the estimated impact on fair values resulting from potential fluctuations in current prices. Credit adjustments are based on estimated defaults by counterparties and are calculated using historical default ratings for corporate bonds for companies with similar credit ratings.

More specifically, the fair value of our retail energy segment electric sales contracts with large commercial, industrial and institutional customers was determined by comparing the contract price to an estimate of the market cost of delivered retail energy and applying the estimated volumes under the provisions of these contracts. The calculation of the estimated cost of energy involves estimating the customer's anticipated load volume, and using forward ERCOT OTC commodity prices, adjusted for the customer's anticipated load characteristics. Load characteristics in the valuation model include: the customer's expected hourly electricity usage profile, the potential variability in the electricity usage profile (due to weather or operational uncertainties), and the electricity usage limits included in the customer's contract. The delivery costs are estimated at the time sales contracts are executed. These costs are based on published rates and our experience of actual delivery costs. Examples of these delivery costs include electric line losses and unaccounted for energy, ERCOT ISO administrative fees, market interaction charges, and may include transmission and distribution fees. Our retail energy segment also enters into supply contracts to substantially hedge the economics of the sales contracts entered into with large commercial, industrial and institutional customers. The fair values of these contracts are estimated using ERCOT OTC forward price and volatility curves and correlations among power and fuel prices specific to the ERCOT Region, net of credit risk.

The fair values of our trading and marketing assets and liabilities are subject to significant changes based on fluctuating market prices and conditions. Changes in the assets and liabilities from trading, marketing, power origination and price risk management services result primarily from changes in the valuation of the portfolio of contracts, newly originated transactions and the timing of settlements. The most significant parameters impacting the value of our portfolio of contracts include natural gas and power forward market prices, volatility and credit risk. For the contracted retail electric sales to large commercial, industrial and institutional customers, significant variables affecting contract values also include the variability in electricity consumption patterns due to weather and operational uncertainties (within contract parameters). Market prices assume a normal functioning market with an adequate number of buyers and sellers providing market liquidity. Insufficient market liquidity could

significantly affect the values that could be obtained for these contracts, as well as the costs at which these contracts could be hedged.

In order to determine the fair value for certain trading energy derivatives, we must rely on modeling techniques. These techniques are used to offset the effects of illiquid markets, in which price discovery is difficult. In certain circumstances, prices are modeled using a variety of techniques such as moving averages, calibration models, and other time series techniques, market equilibrium analysis, extrapolation/interpolation, a range of contingent claims valuation methods and volumetric risk modeling. By using these techniques we are employing all available information to compensate for the lack of price discovery due to market incompleteness.

While we use common industry practices to develop our valuation techniques, changes in our methodologies or the underlying assumptions could result in significantly different fair values and income recognition.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Trading and Marketing Operations" in Item 7 and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K/A for further discussion and measurement of the market exposure in the trading and marketing businesses.

Non-trading Derivative Assets and Liabilities.

To reduce the risk from market fluctuations in revenues and the resulting cash flows derived from the sale of electric power, we may enter into energy derivatives in order to hedge some expected purchases of electric power, natural gas and other commodities and sales of electric power (non-trading energy derivatives). Effective January 1, 2001, we adopted SFAS No. 133, which establishes accounting and reporting standards for derivative instruments, including for hedging activities. This statement requires that 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 accumulated other comprehensive income (loss), net of applicable taxes, depending on the intended use of the derivative, its resulting designation and its effectiveness. We apply hedge accounting for our non-trading energy derivatives utilized in non-trading activities only if there is a high correlation between price movements in the derivative and the item designated as being hedged. The gains and losses related to derivative instruments and contractual commitments qualifying and designated as hedges are deferred in accumulated other comprehensive income (loss) to the extent the contracts are effective as a hedge, and then are recognized in our results of operations in the same period as the settlement of the underlying hedged transaction. The fair values and deferred gains and losses of derivative instruments and contractual commitments qualifying and designated as hedges are based on the same valuation techniques described above for trading and marketing assets and liabilities. For a derivative not designated as a hedging instrument, the gain or loss is recognized in earnings in the period it occurs based on the same valuation techniques described above for trading and marketing assets and liabilities. For additional discussion of our accounting policies for non-trading derivatives, see note 7 to our consolidated financial statements.

Payment to CenterPoint.

We may be required to make a payment to CenterPoint in 2004 to the extent our price to beat for providing retail electric service to residential and small commercial customers in CenterPoint's Houston service territory during 2002 and 2003 exceeds the market price of electricity. This payment is required unless, on or prior to January 1, 2004, 40% or more of the amount of electric power that was consumed in 2000 by residential or small commercial customers, as applicable, within CenterPoint's Houston service territory is committed to be served by retail electric providers other than us. As of December 31, 2002, our estimate for the payment related to residential customers is between $160 million and $190 million (pre-tax), with a most probable estimate of $175 million. As of December 31, 2002, we have accrued $128 million (based on the recognition of the related revenues) relating to this probable payment to CenterPoint and will recognize the remainder of the obligation in 2003. Currently, we believe that the 40% test for small commercial customers will be met and we will not make a

payment related to those customers. If the 40% test is not met related to our small commercial customers and a payment is required, we estimate this payment would be approximately $30 million.

In determining this range and the amount to accrue as of December 31, 2002, there are certain factors which require estimates and assumptions by us: (a) the market price of electricity for the period from January 1, 2002 through December 31, 2003 and (b) the number of residential and small commercial electric customers that we will have in CenterPoint's Houston service territory on January 1, 2004, less the number of customers which we will have on that date in other service territories in Texas.

We are accruing the potential payment liability for residential customers based on (a) the difference of (i) the price to beat, which we are charging our customers and (ii) the market rate as determined based on the EFL filed by our primary competitor multiplied by (b) the amount of electric power consumed by our residential customers in CenterPoint's Houston service territory during that time period. The EFL is filed by each retail electric provider on the first day of the calendar year and each time a provider's rates change. There is the chance that the PUCT will determine that a different price should be used as the market price. However, we have assumed that we will be paying up to the maximum amount of $150 per net residential customer, based on the number of residential customers served within CenterPoint's Houston service territory less the number of residential customers which we will have in other service territories in Texas. Therefore, there would be no impact to our consolidated financial statements over the two-year time period if this were to occur. In the future, we will revise our estimates of this payment as additional information about the market price of electricity and the market share that will be served by us and other retail electric providers on January 1, 2004 becomes available and we will adjust the related accrual at that time.

We monitor our customer acquisition and attrition rates, both in the CenterPoint Houston service territory and in other service territories in Texas. We have projected our number of residential and small commercial customers as of January 1, 2004 based on these monthly trend lines and expected changes that may occur as a result of additional activities in the market. These include both the number of customers we serve in the Houston service territory as well as other areas of Texas. We are assuming a certain number of residential and small commercial customers within our Houston service territory switch to other providers for their electricity. We have accrued and estimated our most probable payment based on our most likely business plan. However, the possibility of a higher or lower customer count exists based on the changes in the level of competition and other factors, such as new entrants into the market, competitor pricing and marketing activities. Holding all other factors constant, if the percentage of our number of residential customers in our Houston service territory increases four percentage points, our payment to CenterPoint in 2004 would increase approximately $10 million. We have also assumed that we gain market share in other areas (outside of Houston) of Texas. We have assumed a certain percentage of residential customers switch from their current retail electric provider to another provider and have assumed that we gain a certain percentage of those that switched. Holding all other factors constant, if the percentage of residential customers that we gain is one percentage point less than we are estimating, our payment to CenterPoint in 2004 would increase by approximately $5 million.

For additional information regarding this payment, see note 14(e) to our consolidated financial statements.

Retail Energy Segment Accrued Unbilled Revenue.

We record revenue for retail and other energy sales under the accrual method. For retail customers, revenues are recognized when the services are provided on the basis of periodic cycle meter readings by the transmission and distribution utility. The transmission and distribution utilities send the information to the ERCOT ISO, which in turn sends the information to us. Each month we estimate the volume of electricity consumed from the last meter reading for that month to the end of the month based on historical customer volumes, usage by customer class and weather factors. We estimate a rate for each MWh of usage using a mix by customer class determined by using historical trends, contract prices, regulatory rates and experience. The volume estimate is then multiplied by our estimated rate to calculate the unbilled revenue to be recorded. We record the unbilled revenue

in the current reporting period and then reverse in the subsequent reporting period when actual usage and rates are known and billed. Unbilled revenues recognized at December 31, 2002 totaled $216 million, representing approximately 2% of our 2002 revenue. Our unbilled revenue included $25 million related to delayed billings. Assuming a 3% increase or decrease in either our estimate of electricity usage volumes or estimated rate per MWh, our unbilled revenue at December 31, 2002 would increase or decrease by approximately $6 million, respectively. Alternatively, a 3% increase or decrease in both our estimated electricity usage and estimated rate per MWh would increase or decrease our unbilled revenue at December 31, 2002 by approximately $13 million.

Retail Energy Segment Cost of Sales Recognition.

We record our purchased power cost for our electricity sales and services to retail customers based on estimated supply volumes and an estimated rate per MWh for the applicable reporting period. The estimated supply volumes consider the effects of historical customer volumes, weather factors and usage by customer class. We estimate a rate for each MWh of usage using a mix by customer class determined by using historical trends, contract prices, regulatory rates and experience. The volume estimate is then multiplied by the estimated rate per MWh and recorded as purchased power expense in the applicable reporting period.

The ERCOT ISO is responsible for handling, scheduling and settlement for all electricity volumes in the Texas deregulated electricity market. As part of the settlement, the ERCOT ISO communicates the actual volumes compared to the scheduled volumes. The ERCOT ISO calculates an additional charge or credit based on the difference between the actual and scheduled volumes, based on a market-clearing price. Preliminary settlement information is due from the ERCOT ISO within two months after electricity is delivered with final settlement information due within twelve months after electricity is delivered. As a result, we adjust our estimated purchase power expense upon receipt of settlement and consumption information. Additionally, we compare the ERCOT ISO volumes usage data to our retail billing usage data and adjust for the volume difference at the ERCOT ISO market-clearing price. Historically, our volume estimates were adjusted in subsequent reporting periods by an average of 2% to 5% in either direction, while our adjustments to the estimated rate per MWh were nominal. Assuming a 3% increase or decrease in our estimate of electricity usage volumes purchased on an average month, our purchased power expense at December 31, 2002 would have been increased or decreased by approximately $5 million. Changes in our volume usage would result in a similar change in billed volumes, thus volume changes impacting purchased power expense would be partially mitigated.

The ERCOT ISO settlement process was delayed due to operational problems between the ERCOT ISO, the transmission and distribution utilities and the retail electric providers. During the third quarter of 2002, the ERCOT ISO began issuing final settlements for the pilot time period of July 31, 2001 to December 31, 2001. The final settlements have been suspended until a market synchronization of all customers between the market participants takes place. The market synchronization will validate which retail electric provider served each customer, for each day, beginning as of January 1, 2002, which was the date the market opened to retail competition. Once this market synchronization is complete, the ERCOT ISO will resume the final settlement process beginning with January 1, 2002. The delay in the ERCOT ISO settlement process could impact our ability to accurately reflect our energy supply costs.

We record our transmission and distribution charges using the same method detailed above for our electricity sales and services to retail customers. At December 31, 2002, the transmission and distribution charges not billed by the transmission and distribution utilities to us totaled $59 million. Delays or inaccurate billings from the transmission and distribution utilities could impact our ability to accurately reflect our transmission and distribution costs.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations—EBIT by Business Segment—Retail Energy" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Risks Related to Our Retail Energy Operations" in Item 7 of this Form 10-K/A for further discussion regarding our risks associated with information received from the ERCOT ISO.

Deferred Tax Assets Valuation Allowance.

We are required to estimate whether recoverability of our deferred tax assets is more likely than not. We periodically assess the probability of recovery of recorded deferred tax assets based on our forecast of future earnings outlooks by tax jurisdiction. We use historical and projected future operating results, based upon approved business plans, including a review of the eligible carryforward period, tax planning opportunities and other relevant considerations. Such estimates are inherently imprecise. Many assumptions are utilized in the assessment that may prove to be materially incorrect in the future. We have evaluated the need for valuation allowances of our net deferred tax assets based on the likelihood of expected future taxable benefits. As of December 31, 2001, our valuation allowance for all of our deferred tax assets was $16 million. During 2002, we recorded $25 million additional valuation allowance through income tax expense and $30 million in connection with the Orion Power acquisition, resulting in a deferred tax asset valuation allowance of $71 million as of December 31, 2002. We continue to evaluate the need for a valuation allowance on a quarterly basis and any change in the amount that we expect to ultimately realize will be included in income, as appropriate, in the period in which such a determination is reached. For further discussion of our income taxes, see note 13 to our consolidated financial statements.

Contingencies.

We follow SFAS No. 5 to determine accounting and disclosure requirements for contingencies. We are involved in legal proceedings before various courts and governmental agencies, some of which involve substantial amounts. In addition, we are subject to a number of ongoing investigations by various governmental agencies, such as the FERC, the PUCT, the SEC, the Internal Revenue Service, the EPA and the Department of Labor. Certain of these proceedings and investigations are the subject of intense, highly charged media and political attention. As these matters progress, additional issues may be identified that could expose us to further proceedings and investigations. Our management regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters that can be estimated. Accounting for contingencies requires significant judgment by us regarding the estimated probabilities and ranges of exposure to potential liability. Unless otherwise indicated in note 14(h) to our consolidated financial statements, the ultimate outcome of the various lawsuits, proceedings and investigations cannot be predicted at this time. The ultimate disposition of some of these matters could have a material adverse effect on our financial condition, results of operations and cash flows. For further discussion of our various contingencies, see note 14 to our consolidated financial statements.

Pension and Postretirement Benefits.

We account for our pension and post retirement benefit obligations in accordance with the provisions of SFAS No. 87 and SFAS No. 106. These standards require the use of assumptions such as the discount rate, estimated return on plan assets, compensation increases and the current level and escalation of health care costs in the future. On an annual basis, we determine the assumptions to be used to compute pension and postretirement expense and pension contributions based upon discussions with outside actuaries and other consultants. We believe the two most critical assumptions in determining the benefit obligations for these plans are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected long-term rate of return on plan assets, which reflects the average rate of earnings expected on the funds invested over the life of the plans. In addition, the healthcare cost trend rate has a significant effect on the reported amounts for the accumulated post retirement benefit obligation and related expense. Note 12(d) to our consolidated financial statement describes the impact of a one-percentage point change in the health care cost trend rates; however, there can be no certainty that a change would be limited to only one percentage point.

The pension and postretirement liability and future pension and postretirement expense both increase as the discount rate is reduced. We determined our discount rate assumption based on the current rates earned on long-term bonds that receive one of the two highest ratings given by a recognized rating agency. Lowering the

discount rate by 1.0% (from a range of 6.6% - 6.75% to a range of 5.6% - 5.75%) would increase our pension liability and postretirement liability at December 31, 2002 by approximately $14 million and $16 million, respectively, and increase our estimated 2003 pension expense and postretirement benefit expense by approximately $3 million and $2 million, respectively. During 2001 and 2002, we lowered our assumed discount rate for pension and postretirement benefits by 0.25% and 0.50%, respectively, to reflect current interest rate conditions.

Pension expense increases as the expected long-term rate of return on plan assets decreases. We developed our expected long-term rate of return on plan assets assumption by evaluating input from our retirement plan investment advisors, review of asset class return expectations of a survey of Fortune 500 companies, as well as long-term inflation assumptions. Lowering our assumption of the expected long-term rate of return on our plan assets by 1.0% (from 8.5% to 7.5%) would increase our estimated 2003 pension expense by approximately $0.3 million. During 2001 and 2002, we lowered our expected long-term rate of return assumption by 0.50% and 1.0%, respectively, to reflect the impact of recent trends and our long-term view.

A difference in the assumed rates and the actual rates, which will not be known for decades, can be significant in relation to the obligation and the annual expense recorded for these plans.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Market Risk

We are exposed to various market risks. These risks arise from transactions entered into in the normal course of business and are inherent in our consolidated financial statements. Most of the revenues, results of operations and cash flows from our business activities are impacted by market risks. Categories of market risks include exposures to commodity prices through trading and marketing activities and non-trading activities, interest rates, foreign currency exchange rates and equity prices. A description of each market risk category is set forth below:

- commodity price risk results from exposures to changes in spot prices, forward prices and price volatilities of commodities, such as electricity, natural gas and other energy commodities;
- interest rate risk primarily results from exposures to changes in the level of borrowings and changes in interest rates;
- currency rate risk results from exposures to changes in the value of foreign currencies relative to our reporting currency, the U.S. dollar, and exposures to changes in currency rates in transactions executed in currencies other than a business segment's reporting currency; and
- equity price risk results from exposures to changes in prices of individual equity securities.

We seek to manage these risk exposures through the implementation of our risk management policies and procedures. During the normal course of business, we review our hedging strategies and determine the hedging approach we deem appropriate based upon the circumstances of each situation. We frequently utilize derivative instruments to execute our risk management and hedging strategies.

Derivative instruments are instruments, such as futures, forward contracts, swaps or options that derive their value from underlying assets, indices, reference rates or a combination of these factors. These derivative instruments include negotiated contracts, which are referred to as over-the-counter derivatives, and instruments that are listed and traded on an exchange.

Our trading and marketing businesses utilize derivative instruments as a means to optimize our power generation portfolio, manage commodity price risk, and take market positions. In addition, we use derivative instruments in our non-trading operations to manage and hedge exposures, such as exposure to changes in electricity and fuel prices, interest rate risk on our floating-rate borrowings and foreign currency risk related to

our foreign investments. We believe that the associated market risk of these instruments can best be understood relative to the underlying assets or risk being hedged and our trading strategy. In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions.

Given our current credit and liquidity situation and other factors, we have reduced the level of our marketing and hedging activities, which could result in greater volatility in future earnings. Additionally, the reduction in market liquidity may impair the effectiveness of our risk management procedures and hedging strategies. These and other factors may adversely impact our results of operations, financial condition and cash flows. For further discussion of our current liquidity situation and related impacts, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" in Item 7 of this Form 10-K/A.

For information regarding our commodity price risk, see "Management Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Risks Related to Our Wholesale Energy Operations" in Item 7 of this Form 10-K/A.

Trading Market Risk

We employ a risk management system to mitigate the risks associated with trading and marketing operations. These operations involve market risk associated with managing energy commodities and establishing strategic positions in the energy markets, primarily on a short-term basis, by utilizing energy derivative instruments. Our trading and marketing businesses depend on price and volatility changes to create business opportunities, but these businesses must control risk within authorized limits.

We primarily assess the risk of our trading and marketing positions using a value at risk method, in order to maintain our total exposure within authorized limits. Value at risk is the potential loss in value of trading positions due to adverse market movements over a defined time period within a specified confidence level. We utilize the parametric variance/covariance method with delta/gamma approximation to calculate value at risk, which relies on statistical relationships to describe how changes in commodity and commodity derivatives prices can affect a portfolio of instruments with different characteristics and market exposures. The delta/gamma approximation captures most of the effects of option price risk in the portfolio.

Our value at risk limits are set by our board of directors, as further discussed below. Violations in overall value at risk limits are required to be reported to the audit committee of our board of directors pursuant to our corporate-wide risk limit policy. For further discussion on our risk management framework, see "—Risk Management Structure" below. Risk limits in trading and marketing operations include both value at risk as well as other non-statistical measures of portfolio exposure. The risk management process supplements the measurement and enforcement of the limit metrics with additional analyses including stress testing the portfolio for extreme events and back-testing the value at risk model.

Our value at risk model utilizes four major parameters: confidence level, volatility, correlation and holding period.

- Confidence level: Natural gas and petroleum products have a confidence interval of 95% and power products have a confidence interval of 99%. The confidence level for power products is higher in order to capture the non-normality of power price behavior.
- Volatility: Calculated daily from historical forward prices using the exponentially weighted moving average method.
- Correlation: Calculated daily from daily volatilities and historical forward prices using the exponentially weighted moving average method. This parameter is included to account for the diversification of the portfolio.

- Holding period: Natural gas and petroleum products generally have one day holding periods. Power products have holding periods of 1 to 20 days based on the risk profile of the portfolio. The holding periods for power products reflect our efforts to appropriately account for possible liquidation periods of more than one day, which is reasonable for some non-standard products.

Assuming a confidence level of 95% and a one-day holding period, if value at risk is calculated at $10 million, we may state that there is a one in 20 chance that if prices move against our consolidated diversified positions, our pre-tax loss in liquidating or offsetting with hedges, our applicable portfolio in a one-day period would exceed $10 million.

While we believe that our assumptions and approximations are reasonable for calculating value at risk, there is no uniform industry methodology for estimating value at risk, and different assumptions and/or approximations could produce materially different value at risk estimates.

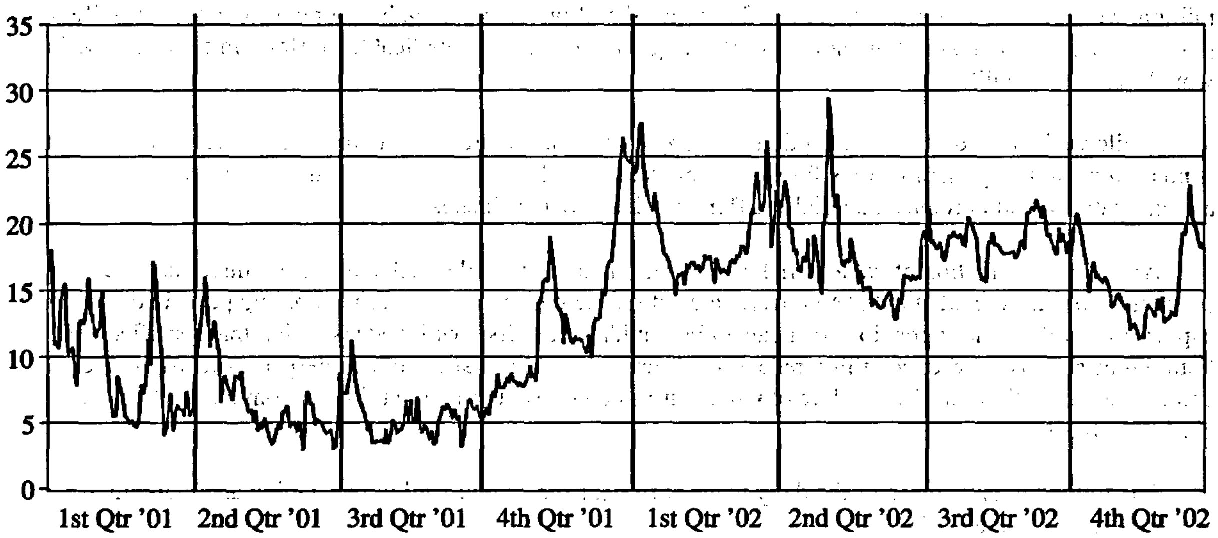
An inherent limitation of value at risk is that past changes in market risk may not produce accurate predictions of future market risk. Moreover, value at risk calculated for a specified holding period does not fully capture the market risk of positions that cannot be liquidated or offset with hedges within that specified period. Future transactions, market volatility, reduction of market liquidity, failure of counterparties to satisfy their contractual obligations and/or a failure of risk controls could result in material losses from our trading and marketing businesses.

The following table presents the daily value at risk for substantially all of our trading and marketing positions for 2001 and 2002:

	2001	2002
	(In millions)	
As of December 31	$27	$19
Year Ended December 31:		
Average	9	18
High	27	29
Low	3	11

The following chart sets forth the daily value at risk for substantially all of our trading energy contracts for 2001 and 2002 (in millions):

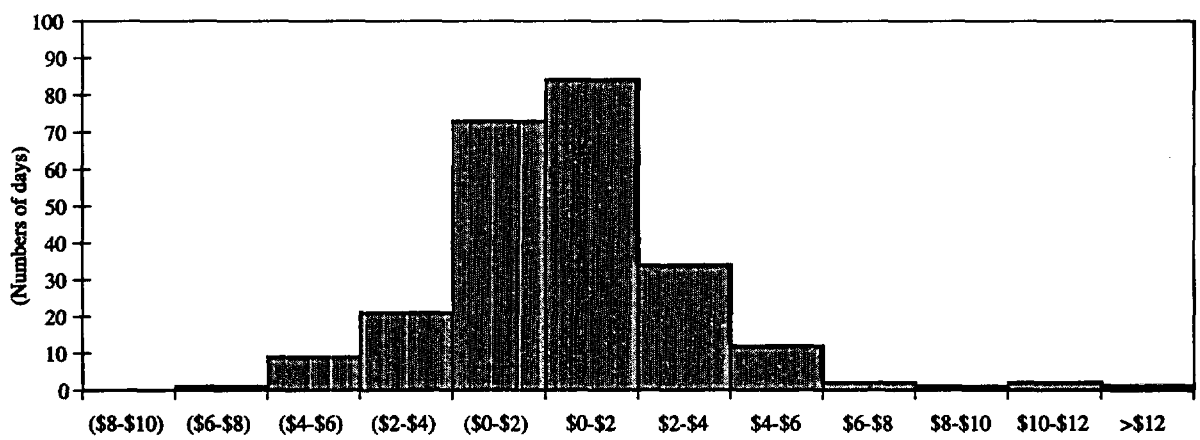
Combined Wholesale, Retail and European Value at Risk



During 2002, average value at risk exposure was higher compared to 2001 due to increased power marketing activities in ERCOT related to our retail energy segment. Value at risk exposure dropped to lower levels at the end of 2002 as a result of decreased liquidity in the energy trading and marketing industry, which led to lower market volatility and consequently, lower value at risk. The increase in value at risk during the middle of December 2002 was due to an increase in market prices and an increase in market volatility.

The following chart presents the distribution of our daily margins for our trading and marketing activities for our wholesale energy segment during 2002 (in millions):

Distribution of Daily Margin of the Trading Portfolio for Wholesale Energy Segment
Year Ended December 31, 2002



Non-trading Market Risk

Commodity Price Risk. Commodity price risk is an inherent component of our electric power generation businesses because the profitability of our generation assets depends significantly on commodity prices sufficient to create margins. Prior to 2002, the majority of our non-trading commodity price risk was related to our electric power generation businesses. Prior to the energy delivery period, we attempt to hedge, in part, the economics of our electric power facilities by selling power and purchasing equivalent fuel. Some power capacity is held in reserve and sold in the spot market. Beginning in 2002, our commodity price risk exposures related to our retail energy operations increased, as we began to provide retail electric services to all customers of CenterPoint's electricity utility division who did not select another retail electric provider. Derivative instruments are used to mitigate exposure to variability in future cash flows from probable, anticipated future transactions attributable to a commodity risk. In this way, more certainty is provided as to the financial contribution associated with the operation of these assets and operations. For a discussion of risk factors affecting our operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors" in Item 7 of this Form 10-K/A.

Derivative instruments, which we use as economic hedges, create exposure to commodity prices, which, in turn, offset the commodity exposure inherent in our businesses. The stand-alone commodity risk created by these instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge, is described below. We measure the commodity risk of our non-trading energy derivatives using a sensitivity analysis. The sensitivity analysis performed on our non-trading energy derivatives measures the potential loss in earnings based on a hypothetical 10% movement in energy prices. An increase of 10% in the market prices of energy commodities from their December 31, 2002 levels would have decreased the fair value of our non-trading energy derivatives by $72 million, excluding non-trading derivative liabilities associated with our European energy segment's stranded cost import contract.

The above analysis of the non-trading energy derivatives utilized for hedging purposes does not include the favorable impact that the same hypothetical price movement would have on our physical purchases and sales of natural gas and electric power to which the hedges relate. Furthermore, the non-trading energy derivative portfolio is managed to complement the physical transaction portfolio, thereby reducing overall risks within limits. Therefore, the adverse impact to the fair value of the portfolio of non-trading energy derivatives held for hedging purposes associated with the hypothetical changes in commodity prices referenced above would be offset by a favorable impact on the underlying hedged physical transactions, assuming:

- the non-trading energy derivatives are not closed out in advance of their expected term;
- the non-trading energy derivatives continue to function effectively as hedges of the underlying risk; and
- as applicable, anticipated underlying transactions settle as expected.

If any of the above-mentioned assumptions cease to be true, a loss on the derivative instruments may occur, or the options might be worthless as determined by the prevailing market value on their termination or maturity date, whichever comes first. Non-trading energy derivatives intended as hedges, and which are effective as hedges, may still have some percentage which is not effective. The change in value of the non-trading energy derivatives, which represents the ineffective component of the hedges, is recorded in our results of operations. During 2001 and 2002, we recognized a gain of $37 million and a loss of $8 million, respectively, in our results of operations due to hedge ineffectiveness.

Our European energy segment's stranded cost import contracts have exposure to commodity prices. A portion of this exposure has been hedged with financial derivatives as of December 31, 2002. For information regarding these contracts, see notes 7(b) and 14(j) to our consolidated financial statements. A decrease of 10% in market prices of energy commodities from their December 31, 2002 levels would result in a loss of earnings of $10 million, including the impact on the related hedging instruments.

Interest Rate Risk. We have issued long-term debt and have obligations under bank facilities that subject us to the risk of loss associated with movements in market interest rates. For information regarding the impact of our March 2003 refinancing of our credit facilities on interest expense, see "Liquidity and Capital Resources—Consolidated Future Uses and Sources of Cash and Certain Factors Impacting Future Uses and Sources of Cash" in Item 7 of this Form 10-K/A.

Our floating-rate obligations aggregated $1.1 billion and $6.7 billion at December 31, 2001 and 2002, respectively. If the floating interest rates were to increase by 10% from December 31, 2002 rates, our interest expense would increase by a total of $2 million each month in which such increase continued.

At December 31, 2001 and 2002, we had issued fixed-rate debt to third parties aggregating $121 million and $637 million, excluding Liberty's fixed-rate debt of $165 million. As of December 31, 2001, fair values were estimated to be equivalent to the carrying amounts of these instruments. As of December 31, 2002, the fair-market value of our fixed-rate debt, excluding Liberty's fixed-rate debt of $165 million, was $448 million. These instruments are fixed-rate and, therefore, do not expose us to the risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments, excluding Liberty's fixed-rate debt, would increase by $32 million if interest rates were to decline by 10% from their rates at December 31, 2002. For a discussion regarding the fair value of the $165 million Liberty fixed-rate debt, see note 18 to our consolidated financial statements.

As of December 31, 2002, we have interest rate swap contracts with an aggregate notional amount of $1.1 billion that fix the interest rate applicable to floating rate short-term debt and floating rate long-term debt. These swaps could be terminated at a cost of $65 million at December 31, 2002. These swaps qualify for hedge accounting under SFAS No. 133 and the periodic settlements are recognized as an adjustment to interest expense in the results of operations over the term of the swap agreement. A decrease of 10% in the December 31, 2002 level of interest rates would increase the cost of terminating the swaps by $9 million. For information regarding the accounting for these interest rate swaps, see notes 7(b) and 9(d) to our consolidated financial statements.

Foreign Currency Exchange Rate Risk. Our European operations expose us to risk of loss in the fair value of our foreign investments due to the fluctuation in foreign currencies relative to our reporting currency, the U.S. dollar. Additionally, our European energy segment transacts in several currencies, although the majority of its business is conducted in the Euro and prior to January 2001, the Dutch Guilder. Until December 2002, we substantially hedged our entire net investment in our European subsidiaries against a material decline of the Euro through a combination of Euro-denominated borrowings, foreign currency swaps, options and forward contracts to reduce our exposure to changes in foreign currency rates. In December 2002, we reduced our hedged position by approximately $1.1 billion to $1.4 billion by using a combination of Euro-denominated borrowings and foreign currency options to reduce our exposure to changes in foreign currency rates. Changes in the value of the foreign currency hedging instruments and debt are recorded as foreign currency translation adjustments as a component of accumulated other comprehensive loss in stockholders' equity. As of December 31, 2001 and 2002, we had recorded a loss of $96 million and a gain of $33 million, respectively, in cumulative net translation adjustments. The cumulative translation adjustments will be realized in earnings and cash flows only upon the disposition of the related investments. During the normal course of business, we review our currency hedging strategies and determine the hedging approach we deem appropriate based upon the circumstances of each situation. In February 2003, we signed a share purchase agreement to sell our European energy operations to Nuon, a Netherlands-based electricity distributor. For a discussion of the sale, see note 21(b) to our consolidated financial statements.

As of December 31, 2002, our European energy segment had entered into transactions to purchase $143 million at fixed exchange rates in order to hedge future fuel purchases payable in U.S. dollars. As of December 31, 2002, the fair value of these financial instruments was a $2 million liability. An increase in the value of the Euro of 10% compared to the U.S. dollar from their December 31, 2002 levels would result in a loss in the fair value of these foreign currency financial instruments of $13 million.

Our European energy segment's stranded cost import contracts have foreign currency exposure. A decrease of 10% in the U.S. dollar relative to the Euro from their December 31, 2002 levels would result in a loss of earnings of $10 million.

Equity Price Risk. We have equity investments, which are classified as "available-for-sale" under SFAS No. 115. As of December 31, 2001 and 2002, the value of these securities was $12 million and $3 million, respectively. A 10% decline in the market value per share of these securities from December 31, 2002 would decrease the fair value by less than $1 million.

Risk Management Structure

We have a risk control framework designed to limit, monitor, measure and manage the risk in our existing portfolio of assets and contracts and to authorize new transactions. These risks include market, credit and liquidity exposures. We believe that we have effective procedures for evaluating and managing these risks to which we are exposed. Key risk control activities include limits on trading and marketing exposures and products, credit review and approval, credit and performance risk measurement and monitoring, validation of transactions, portfolio valuation and daily portfolio reporting including mark-to-market valuation, value at risk and other risk measurement metrics.

We seek to monitor and control our risk exposures through a variety of separate but complementary processes and committees, which involve business unit management, senior management and our board of directors, as detailed below.

Board of Directors. Our board of directors affirms the overall strategy and approves overall risk limits for commodity trading and marketing.

Audit Committee. The audit committee of our board of directors periodically reviews the adequacy of our risk assessment and risk management controls and policies with our management and director of internal auditing.

Executive Management. Our executive management appoints the risk oversight committee members, reviews and approves recommendations of the risk oversight committee prior to presentations to the audit committee of our board of directors, and approves and monitors broad risk limit allocations to the business segments and product types. Our executive management receives daily position reports of our trading and marketing activities.

Risk Oversight Committee. The risk oversight committee, which is comprised of corporate officers and includes a working group of corporate and business segment officers, oversees all of our trading, marketing and hedging activities and other activities involving market risks. These activities expose us to commodity price, credit, foreign currency and interest rate risks. The risk oversight committee meets at least monthly. For trading, marketing and hedging activities, the risk oversight committee:

- monitors compliance of our trading units;
- determines the position reporting requirements for trading and marketing activity;
- recommends adjustments to trading limits, products and policies to the audit committee of our board of directors;
- approves business segments' detailed risk control policies;
- allocates board of director-approved trading and marketing risk capital limits, including value at risk limits;
- approves new trading, marketing and hedging products and commodities;
- approves entrance into new trading markets;
- monitors processes and information systems related to the management of our risk to market exposures; and
- places guidelines and limits around hedging activities.

Commitment Review Committee. The commitment review committee, which is comprised of corporate officers, establishes corporate-wide standards for the evaluation of capital projects and other significant commitments and makes recommendations to the chief executive officer. The commitment review committee is scheduled to meet on an as-needed basis.

Corporate Risk Control Organization. Our corporate risk control organization has corporate-wide oversight for maintaining consistent application of corporate risk policies within individual business segments. The corporate risk control organization is also directly responsible for all business unit risk control activities. The corporate risk control organization:

- recommends the corporate-wide risk management policies and procedures which are approved by the audit committee of our board of directors;
- provides updates of trading and marketing activities to the audit committee of our board of directors on a regular basis;
- provides oversight of our ongoing development and implementation of operational risk policies, framework and methodologies;
- monitors effectiveness of the corporate-wide risk management policies, procedures and risk limits;
- evaluates the business segment risk control organizations, including information systems and reporting;
- evaluates allocation of risk limits within our business segments;
- reviews inherent risks in proposed transactions;
- reviews daily position reports of trading and marketing activities;
- develops and maintains the risk control infrastructure, including policies, processes, personnel and information and valuation systems, to analyze and report the daily risk positions to executive management, the risk oversight committee, the internal audit department and the controllers organization;
- reviews credit exposures for customers and counterparties;
- reviews all significant valuation methodologies, assumptions and models used for risk measurement, mark-to-market valuations and structured transaction evaluations;
- ensures risk systems can adequately measure positions and related risk exposures for new products and transactions;
- evaluates new transactions for compliance with risk policies and limits; and
- evaluates effectiveness of hedges.

The management of each of the business segments is responsible for the management of its risks and for maintaining a conducive environment for effective risk control activities as part of its overall responsibility for the proper management of the business unit. Commercial management has in-depth knowledge of the primary sources of risk in their individual markets and the instruments available to hedge our exposures. Commercial management allocates risk limits that have been allocated to specific markets and to individual traders, within the limits imposed by the risk oversight committee. Risk limits are monitored on a daily basis. Risk limit violations, including value at risk violations, are reported to the appropriate level of management in the business segment and corporate organization, depending on the type and severity of the violations.

Segregation of duties and management oversight are fundamental elements of our risk management process. There are segregation of duties among the trading and marketing functions; transaction validation and documentation; risk measurement and reporting; settlements function; accounting and financial reporting functions; and treasury function. These risk management processes and related controls are reviewed by our corporate internal audit department on a regular basis. When appropriate, external advisors or consultants with relevant experience will assist in reviews.

The effectiveness of our policies and procedures for managing risk exposure can never be completely estimated or fully assured. For example, we could experience losses, which could have a material adverse effect on our financial condition, results of operations or cash flows from unexpectedly large or rapid movements or disruptions in the energy markets, from regulatory-driven market rules changes and/or bankruptcy of customers or counterparties.

For information regarding a loss related to certain of our natural gas trading positions in the first quarter of 2003, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—EBIT by Business Segment—Wholesale Energy" in Item 7 of this Form 10-K/A.

ITEM 8. *Financial Statements and Supplementary Data.*

INDEX TO FINANCIAL STATEMENTS

RELIANT RESOURCES, INC. AND SUBSIDIARIES

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Reliant Resources, Inc. and Subsidiaries
Houston, Texas

We have audited the accompanying consolidated balance sheets of Reliant Resources, Inc. and Subsidiaries (the Company), as of December 31, 2001 and 2002, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2002. Our audits also include the financial statement schedules listed in the Index at Item 15(a)(2). These financial statements and the financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedules based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2001 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in notes 7, 6 and 2 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities in 2001 and changed its method of accounting for goodwill and other intangibles and its method of presenting its trading and marketing activities from a gross basis to a net basis in 2002, respectively.

As discussed in note 1, the accompanying 2000 and 2001 consolidated financial statements have been restated.

DELOITTE & TOUCHE LLP

Houston, Texas
March 31, 2003 (April 29, 2003 as to Schedule I listed in the Index at Item 15(a)(2))

RELIANT RESOURCES, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED OPERATIONS

(Thousands of Dollars, except per share amounts)

	Year Ended December 31,		
	2000 (As Restated, see note 1)	2001 (As Restated, see note 1)	2002
Revenues:			
Revenues	$3,275,246	$6,129,942	$11,248,486
Trading margins (See notes 2(d) and 2(t))	199,793	369,436	309,512
Total	3,475,039	6,499,378	11,557,998
Expenses:			
Fuel and cost of gas sold	1,171,378	1,975,674	1,442,784
Purchased power	925,942	2,509,045	7,380,814
Accrual for payment to CenterPoint Energy, Inc.	—	—	128,300
Operation and maintenance	422,314	494,286	903,138
General, administrative and development	304,061	503,150	665,030
European energy goodwill impairment	—	—	481,927
Depreciation	114,825	152,479	385,066
Amortization	78,857	94,285	50,858
Total	3,017,377	5,728,919	11,437,917
Operating Income	457,662	770,459	120,081
Other (Expense) Income:			
(Losses) gains from investments, net	(16,509)	22,040	(24,215)
Income of equity investment of unconsolidated subsidiaries	42,860	57,440	22,617
Gain on sale of development project	18,011	—	—
Other, net	5,963	8,890	33,426
Interest expense	(42,337)	(63,268)	(304,201)
Interest income	17,732	26,645	35,431
Interest (expense) income—affiliated companies, net	(172,269)	12,477	4,754
Total other (expense) income	(146,549)	64,224	(232,188)
Income (Loss) Before Income Taxes, Cumulative Effect of Accounting Change and Extraordinary Item	311,113	834,683	(112,107)
Income Tax Expense	95,893	274,394	214,105
Income (Loss) Before Cumulative Effect of Accounting Change and Extraordinary Item	215,220	560,289	(326,212)
Cumulative effect of accounting change, net of tax	—	3,062	(233,600)
Extraordinary item, net of tax	7,445	—	—
Net Income (Loss)	$ 222,665	$ 563,351	$ (559,812)
Basic and Diluted Earnings (Loss) per Share:			
Income (loss) before cumulative effect of accounting change		$ 2.02	$ (1.12)
Cumulative effect of accounting change, net of tax		0.01	(0.81)
Net income (loss)		$ 2.03	$ (1.93)

See Notes to our Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)

	December 31, 2001 (As Restated, see note 1)	December 31, 2002
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 118,453	$ 1,226,526
Restricted cash	167,421	218,769
Accounts and notes receivable and accrued unbilled revenues, principally customer, net	1,182,140	1,522,906
Note receivable related to receivables facility	—	169,582
Accounts and notes receivable—affiliated companies, net	415,081	—
Inventory	174,035	318,893
Stranded costs settlement receivable	201,503	—
Trading and marketing assets	1,046,116	660,014
Non-trading derivative assets	392,900	365,985
Margin deposits on energy trading and hedging activities	213,727	342,452
Collateral for electric generating equipment	141,701	—
Accumulated deferred income taxes	20,814	58,872
Prepayments and other current assets	126,936	187,504
Total current assets	4,200,827	5,071,503
Property, Plant and Equipment, net	4,558,542	8,940,759
Other Assets:		
Goodwill, net	890,912	1,540,506
Other intangibles, net	315,438	736,689
Notes receivable—affiliated companies, net	30,278	—
Equity investments in unconsolidated subsidiaries	386,841	313,112
Trading and marketing assets	393,196	311,989
Non-trading derivative assets	254,168	97,810
Stranded costs indemnification receivable	203,693	202,647
Accumulated deferred income taxes	71,907	3,430
Prepaid lease	121,699	200,052
Restricted cash	—	7,000
Collateral for electric generating equipment	88,268	—
Other	203,645	211,323
Total other assets	2,960,045	3,624,558
Total Assets	$11,719,414	$17,636,820
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt and short-term borrowings	$ 320,538	$ 1,449,845
Accounts payable, principally trade	1,002,326	1,062,541
Trading and marketing liabilities	913,059	542,121
Non-trading derivative liabilities	399,277	342,725
Margin deposits from customers on energy trading and hedging activities	144,700	50,203
Retail customer deposits	8	51,750
Accumulated deferred income taxes	57,848	18,567
Other	253,792	408,192
Total current liabilities	3,091,548	3,925,944
Other Liabilities:		
Accumulated deferred income taxes	25,585	503,033
Trading and marketing liabilities	308,372	239,794
Non-trading derivative liabilities	639,211	315,301
Major maintenance reserve	16,784	23,023
Accrual for payment to CenterPoint Energy, Inc.	—	128,300
Non-derivative stranded costs liability	203,693	202,647
Benefit obligations	127,012	138,365
Other	455,865	462,445
Total other liabilities	1,776,522	2,012,908
Long-term Debt	867,712	6,045,080
Commitments and Contingencies (note 14)		
Stockholders' Equity:		
Preferred stock; par value $0.001 per share (125,000,000 shares authorized; none outstanding)	—	—
Common Stock, par value $0.001 per share (2,000,000,000 shares authorized; 299,804,000 issued)	61	61
Additional paid-in capital	5,789,869	5,836,957
Treasury stock at cost, 11,000,000 and 9,198,766 shares	(189,460)	(158,483)
Retained earnings	563,351	3,539
Accumulated other comprehensive loss	(180,189)	(29,186)
Stockholders' equity	5,983,632	5,652,888
Total Liabilities and Stockholders' Equity	$11,719,414	$17,636,820

See Notes to our Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

(Thousands of Dollars)

	Year Ended December 31, 2000 (As Restated, see note 1)	2001 (As Restated, see note 1)	2002
Cash Flows from Operating Activities:			
Net income (loss)	$ 222,665	$ 563,351	$ (559,812)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
European energy goodwill impairment	—	—	481,927
Depreciation and amortization	193,682	246,764	435,924
Deferred income taxes	(27,476)	32,540	255,097
Net trading and marketing assets and liabilities	(3,984)	(185,136)	22,923
Net non-trading derivative assets and liabilities	—	23,327	(49,878)
Net amortization of contractual rights and obligations	—	—	(3,306)
Curtailment and related benefit enhancement	—	99,523	—
Accounting settlement for certain benefit plans	—	—	47,356
Contributions of marketable securities to charitable foundation	15,172	—	—
Impairment of marketable equity securities and other investments	26,504	—	31,780
Undistributed earnings of unconsolidated subsidiaries	(24,931)	(30,280)	(19,642)
Accrual for payment to CenterPoint, Inc.	—	—	128,300
Gain on sale of development project	(18,011)	—	—
Stranded cost indemnification settlement gain	—	(36,881)	—
Stranded cost contracts settlement gain	—	—	(109,000)
Cumulative effect of accounting change	—	(3,062)	233,600
Extraordinary item	(7,445)	—	—
Other, net	(2,034)	(11,712)	(21,157)
Changes in other assets and liabilities:			
Restricted cash	(50,000)	(117,421)	276,319
Accounts and notes receivable and unbilled revenue, net	(1,174,918)	582,629	90,096
Accounts receivable/payable—affiliated companies, net	(168,692)	92,906	26,603
Inventory	(9,468)	(59,153)	(86,364)
Collateral for electric generating equipment, net	(84,879)	(145,090)	136,013
Margin deposits on energy trading and hedging activities, net	(206,480)	167,374	(219,652)
Net non-trading derivative assets and liabilities	—	(117,858)	(150,964)
Prepaid lease obligation	—	(180,531)	(78,551)
Proceeds from sale of debt securities	123,428	—	—
Other current assets	(92,719)	102,348	(51,426)
Other assets	(103,692)	(39,882)	(13,787)
Accounts payable	1,465,925	(1,064,239)	(114,118)
Taxes payable/receivable	57,016	(13,368)	(11,170)
Other current liabilities	209,216	(55,984)	67
Other liabilities	(11,337)	22,814	(66,662)
Net cash provided by (used in) operating activities	327,542	(127,021)	610,516
Cash Flows from Investing Activities:			
Capital expenditures	(933,180)	(839,908)	(660,526)
Business acquisitions, net of cash acquired	(2,121,408)	—	(2,963,801)
Proceeds from sale-leaseback transactions	1,000,000	—	—
Payment of business purchase obligation	(981,789)	—	—
Investments in unconsolidated subsidiaries	(5,755)	—	—
Distribution from equity investment in unconsolidated subsidiary	—	—	137,475
Other, net	28,830	1,839	674
Net cash used in investing activities	(3,013,302)	(838,069)	(3,486,178)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	770,009	—	22,324
Proceeds from issuance of stock, net	—	1,696,074	—
Payments of long-term debt	(307,201)	(4,084)	(242,478)
(Decrease) increase in short-term borrowings, net	(31,906)	217,323	3,845,505
Change in notes with affiliated companies, net	1,219,946	(731,894)	385,652
Purchase of treasury stock	—	(189,460)	—
Contributions from CenterPoint	1,094,259	9,441	—
Payments of financing costs	(108)	(1,330)	(43,209)
Other, net	(23,843)	3,470	12,932
Net cash provided by financing activities	2,721,156	999,540	3,980,726
Effect of Exchange Rate Changes on Cash and Cash Equivalents	5,088	(5,752)	3,009
Net Increase in Cash and Cash Equivalents	40,484	28,698	1,108,073
Cash and Cash Equivalents at Beginning of Year	49,271	89,755	118,453
Cash and Cash Equivalents at End of Year	$ 89,755	$ 118,453	$ 1,226,526
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest (net of amounts capitalized)	$ 205,103	$ 84,650	$ 301,462
Income taxes	72,784	243,740	10,027

See Notes to our Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

(Thousands of Dollars)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings	Unrealized (Loss) Gain on Available For Sale Securities	Deferred Derivative Gains (Losses)	Foreign Currency Translation Adjustments	Additional Minimum Benefits Liability	Total Accumulated Other Comprehensive (Loss) Income	Total Stockholders' Equity	Comprehensive Income (Loss)
Balance December 31, 1999	$—	$ —	$ —	$ 757,751	$(17,228)	$ —	$ 162	$ —	$(17,066)	$ 740,685	
Net income (As Restated, see note 1)				222,665						222,665	$ 222,665
Contributions from CenterPoint				1,369,278						1,369,278	
Transfer to common stock and additional paid-in capital	1		2,349,693	(2,349,694)						—	
Other comprehensive income (loss):											
Foreign currency translation adjustments							(1,726)		(1,726)	(1,726)	(1,726)
Additional minimum non-qualified pension liability adjustment, net of tax of $0.4 million								(716)	(716)	(716)	(716)
Reclassification adjustment for impairment loss on available-for-sale securities realized in net income, net of tax of $9 million					17,228				17,228	17,228	17,228
Unrealized loss on available-for-sale securities, net of tax of $1 million					(2,264)				(2,264)	(2,264)	(2,264)
Comprehensive income (As Restated, see note 1)											$ 235,187
Balance December 31, 2000 (As Restated, see note 1)	1	—	2,349,693	—	(2,264)	—	(1,564)	(716)	(4,544)	2,345,150	
Net income (As Restated, see note 1)				563,351						563,351	$ 563,351
Contributions from CenterPoint			1,787,311							1,787,311	
Purchases of treasury stock		(189,460)								(189,460)	
Majority owner effect of treasury stock purchases			(43,149)							(43,149)	
IPO proceeds, net	60		1,696,014							1,696,074	
Other comprehensive income (loss):											
Foreign currency translation adjustments, net of tax of $98 million							(94,066)		(94,066)	(94,066)	(94,066)
Changes in minimum non-qualified pension liability, net of tax of $4 million								(6,799)	(6,799)	(6,799)	(6,799)
Cumulative effect of adoption of SFAS No. 133, net of tax of $236 million						(459,944)			(459,944)	(459,944)	(459,944)
Deferred gain from cash flow hedges, net of tax of $228 million						427,994			427,994	427,994	427,994
Reclassification of net deferred gain from cash flow hedges into net income, net of tax of $35 million						(51,144)			(51,144)	(51,144)	(51,144)
Unrealized gain on available-for-sale securities, net of tax of $9 million					16,984				16,984	16,984	16,984
Reclassification adjustments for gains on sales of available-for-sale securities realized in net income, net of tax of $5 million					(8,670)				(8,670)	(8,670)	(8,670)
Comprehensive income (As Restated, see note 1)											$ 387,706
Balance December 31, 2001 (As Restated, see note 1)	61	(189,460)	5,789,869	563,351	6,050	(83,094)	(95,630)	(7,515)	(180,189)	5,983,632	
Net loss				(559,812)						(559,812)	$(559,812)
Contributions from CenterPoint			47,088							47,088	
Issuance of treasury stock		30,977								30,977	
Other comprehensive income (loss):											
Foreign currency translation adjustments, net of tax of $113 million							128,450		128,450	128,450	128,450
Changes in minimum non-qualified pension liability, net of tax of $3 million								4,869	4,869	4,869	4,869
Deferred gain from cash flow hedges, net of tax of $31 million						38,437			38,437	38,437	38,437
Reclassification of net deferred gain from cash flow hedges into net loss, net of tax of $8 million						(15,819)			(15,819)	(15,819)	(15,819)
Unrealized loss on available-for-sale securities, net of tax of $1 million					(1,672)				(1,672)	(1,672)	(1,672)
Reclassification adjustments for gains on sales of available-for-sale securities realized in net loss, net of tax of $2 million					(3,262)				(3,262)	(3,262)	(3,262)
Comprehensive loss											$(408,809)
Balance December 31, 2002	$61	$(158,483)	$5,836,957	$ 3,539	$ 1,116	$ (60,476)	$32,820	$(2,646)	$(29,186)	$5,652,888	

See Notes to our Consolidated Financial Statements

(1) BACKGROUND AND BASIS OF PRESENTATION

Reliant Resources, Inc., a Delaware corporation, was incorporated in August 2000 with 1,000 shares of common stock which were owned by Reliant Energy, Incorporated (Reliant Energy). We refer to Reliant Resources, Inc. as "Reliant Resources," and to Reliant Resources and its subsidiaries collectively, as "we," "us," or "our," unless the context clearly indicates otherwise. We provide electricity and energy services with a focus on the competitive retail and wholesale segments of the electric power industry in the United States. Throughout much of Texas, we provide standardized electricity and related products and services to residential and small commercial customers with an aggregate peak demand for power up to one megawatt (MW) and offer customized electric commodity and energy management services to large commercial, industrial and institutional customers with an aggregate peak demand for power in excess of one MW. We have built a portfolio of electric power generation facilities, through a combination of acquisitions and development, that are not subject to traditional cost-based regulation; therefore we can generally sell electricity at prices determined by the market, subject to regulatory limitations. We trade and market electricity, natural gas, natural gas transportation capacity and other energy-related commodities. We also optimize our physical assets and provide risk management services for our asset portfolio. In March 2003, we decided to exit our proprietary trading activities and liquidate, to the extent practicable, our proprietary positions. Although we are exiting the proprietary trading business, we have existing positions, which will be closed as economically feasible or in accordance with their terms. We will continue to engage in hedging activities related to our electric generating facilities, pipeline storage positions and fuel positions.

Reliant Energy adopted a business separation plan in response to the Texas Electric Choice Plan (Texas electric restructuring law) adopted by the Texas legislature in June 1999. The Texas electric restructuring law substantially amended the regulatory structure governing electric utilities in Texas in order to allow retail electric competition with respect to all customer classes beginning in January 2002. Under its business separation plan filed with the Public Utility Commission of Texas (PUCT), Reliant Energy transferred substantially all of its unregulated businesses to Reliant Resources in order to separate its regulated and unregulated operations. In accordance with the plan, in May 2001, Reliant Resources offered 59.8 million shares of its common stock to the public at an initial offering price of $30 per share (IPO) and received net proceeds from the IPO of $1.7 billion. For additional information regarding the IPO, see notes 3 and 10(a).

CenterPoint Energy, Inc. was formed on August 31, 2002 as the new holding company of Reliant Energy. We refer to CenterPoint Energy, Inc. and its predecessor company, Reliant Energy, as "CenterPoint." Unless clearly indicated otherwise these references to "CenterPoint" mean CenterPoint Energy, Inc. on or after August 31, 2002 and Reliant Energy prior to August 31, 2002. CenterPoint is a diversified international energy services and energy delivery company that owned the majority of Reliant Resources outstanding common stock prior to September 30, 2002. On September 30, 2002, CenterPoint distributed all of the 240 million shares of our common stock it owned to its common shareholders of record as of the close of business on September 20, 2002 (Distribution). The Distribution completed the separation of Reliant Resources and CenterPoint into two separate publicly held companies.

The operations included in the consolidated financial statements for 2000 consist of CenterPoint's, or its direct and indirect subsidiaries', unregulated power generation and related energy trading, marketing, origination and risk management services in North America and Europe; a portion of its retail electric operations; and other operations, including a communications business and a venture capital operation. Throughout 2000, CenterPoint and its direct and indirect subsidiaries conducted these operations. Effective December 31, 2000, CenterPoint consolidated its unregulated operations under Reliant Resources (Consolidation). A subsidiary of CenterPoint,

Reliant Energy Resources Corp. (RERC Corp.), transferred some of its subsidiaries, including its trading and marketing subsidiaries, to us. In connection with the transfer from RERC Corp., we paid $94 million to RERC Corp. Also effective December 31, 2000, CenterPoint transferred its wholesale power generation businesses, its unregulated retail electric operations, its communications business and most of its other unregulated businesses to us. In accordance with accounting principles generally accepted in the United States of America, the transfers from RERC Corp. and CenterPoint were accounted for as a reorganization of entities under common control.

Restatement

Subsequent to the issuance of our financial statements as of and for the year ended December 31, 2001, we identified four natural gas financial swap transactions that should not have been recorded in our records. We have concluded, based on the offsetting nature of the transactions and manner in which the transactions were documented, that none of the transactions should have been given accounting recognition. We previously accounted for these transactions in our financial statements as a reduction in revenues in December 2000 and an increase in revenues in January 2001, with the effect of decreasing net income in the fourth quarter of 2000 and increasing net income in the first quarter of 2001, in each case by $20.0 million pre-tax ($12.7 million after-tax) and the effect of increasing basic and diluted earnings per share by $0.05 in the first quarter of 2001. There were no cash flows associated with the transactions.

Also, subsequent to the issuance of our financial statements for 2001 and for the first three quarters of 2002, we determined that we had incorrectly calculated the amount of hedge ineffectiveness for 2001 and the first three quarters of 2002 for hedging instruments entered into prior to the adoption of Statement of Financial Accounting Standards (SFAS) No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133). These hedging instruments included long-term forward contracts for the sale of power in the California market through December 2006. The amount of hedge ineffectiveness for these forward contracts was calculated using the trade date. However, the proper date for the hedge ineffectiveness calculation is hedge inception, which for these contracts was deemed to be January 1, 2001, concurrent with the adoption of SFAS No. 133. These errors in accounting for hedge ineffectiveness resulted in an understatement of revenues of $28.7 million ($18.6 million after-tax) and earnings per share of $0.07 in 2001.

The consolidated financial statements for 2000 and 2001 have been restated from amounts previously reported to remove the effects of the four natural gas swap transactions from 2000 and 2001 and to correctly account for the amount of hedge ineffectiveness in 2001. The restatement had no impact on previously reported consolidated operating, investing and financing cash flows for 2000 or 2001. The following is a summary of the principal effects of the restatement for 2000 and 2001: (Note—Those line items for which no change in amounts are shown were not affected by the restatement.)

RELIANT RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

For the Three Years Ended December 31, 2000, 2001 and 2002

	Year Ended December 31, 2000	
	As Restated	As Previously Reported(1)
	(in millions)	
Revenues	$3,275	$3,255
Trading margins	200	200
Total revenues	3,475	3,455
Total operating expenses	3,017	3,017
Operating income	458	438
Other expense, net	147	147
Income before income tax expense and extraordinary item	311	291
Income tax expense	95	88
Income before extraordinary item	216	203
Extraordinary item	7	7
Net income	$ 223	$ 210

	Year Ended December 31, 2001	
	As Restated	As Previously Reported(1)
	(in millions)	
Revenues	$6,130	$6,122
Trading margins	369	369
Total revenues	6,499	6,491
Total operating expenses	5,729	5,729
Operating income	770	762
Other income, net	64	64
Income before income tax expense and cumulative effect of accounting changes	834	826
Income tax expense	274	272
Income before cumulative effect of accounting change	560	554
Cumulative effect of accounting change	3	3
Net income	$ 563	$ 557
Basic Earnings Per Share:		
Income before cumulative effect of accounting change	$ 2.02	$ 2.00
Cumulative effect of accounting change, net of tax	0.01	0.01
Net income	$ 2.03	$ 2.01

	December 31, 2001	
	As Restated	As Previously Reported(2)
	(in millions)	
ASSETS		
Current assets	$ 4,201	$ 4,201
Total long-term assets	7,518	7,518
Total Assets	$11,719	$11,719
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities	$ 3,091	$ 3,091
Total long-term liabilities	2,644	2,644
Stockholders' Equity:		
Preferred stock	—	—
Common Stock	—	—
Additional paid-in capital	5,790	5,777
Treasury stock	(189)	(189)
Retained earnings	563	557
Accumulated other comprehensive loss	(180)	(161)
Stockholders' equity	5,984	5,984
Total Liabilities and Stockholders' Equity	$11,719	$11,719

(1) Beginning with the quarter ended September 30, 2002, we now report all energy trading and marketing activities on a net basis as allowed by Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts involved in Energy Trading and Risk Management Activities" (EITF No. 98-10). Comparative financial statements for prior periods have been reclassified to conform to this presentation. For information regarding the presentation of trading and marketing activities on a net basis, see note 2(t). Revenues, fuel and cost of gas sold expense and purchased power expense have been reclassified to conform to this presentation.

(2) Some amounts from the previous years have been reclassified to conform to the presentation of our consolidated balance sheet as of December 31, 2002. These reclassifications do not affect stockholders' equity or net income.

The effects of the restatement discussed above on the unaudited condensed quarterly financial statement information for 2001 and 2002 have been included in note 19.

Basis of Presentation

The accompanying consolidated financial statements for 2000 are presented on a carve-out basis and include our historical operations. The financial statements for 2000 have been prepared from CenterPoint's historical accounting records.

The statements of consolidated operations include all revenues and costs directly attributable to us, including costs for facilities and costs for functions and services performed by centralized CenterPoint organizations and directly charged to us based on usage or other allocation factors prior to the Distribution. The results of operations in these consolidated financial statements also include general corporate expenses allocated by CenterPoint to us prior to the Distribution. All of the allocations in the consolidated financial statements are based on assumptions that management believes are reasonable under the circumstances. However, these allocations may not necessarily be indicative of the costs and expenses that would have resulted if we had operated as a separate entity prior to the Distribution.

Our financial reporting segments include the following: retail energy, wholesale energy, European energy and other operations. The retail energy segment includes our retail electric operations and associated supply activities. This segment provides customized, integrated energy services to large commercial, industrial and institutional customers and standardized electricity and related services to residential and small commercial customers in Texas. The wholesale energy segment engages in the acquisition, development and operation of domestic non-rate regulated electric power generation facilities as well as wholesale energy trading, marketing, power origination and risk management activities related to energy and energy-related commodities in North America. The European energy segment operates power generation facilities in the Netherlands and conducts wholesale energy trading and origination activities in Europe; see note 21(b) regarding the sale of our European energy operations. The other operations segment primarily includes unallocated general corporate expenses and non-operating investments.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Reclassifications.

Some amounts from the previous years have been reclassified to conform to the 2002 presentation of financial statements. These reclassifications do not affect earnings.

(b) Use of Estimates and Market Risk and Uncertainties.

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

We are subject to the risk associated with price movements of energy commodities and the credit risk associated with our trading, risk management, hedging and retail electric activities. For additional information regarding these risks, see notes 7, 14 and 17. We are also subject to risks relating to effects of competition, changes in interest rates and foreign currencies, results of financing efforts, operation of deregulating power markets, seasonal weather patterns, availability of energy supply, availability of transmission capacity, resolution of lawsuits and regulatory proceedings, technological obsolescence and the regulatory environment in the United States and Europe. In addition, we are subject to risks relating to the reliability of the systems, procedures and other infrastructure necessary to operate our businesses.

(c) Principles of Consolidation.

Our accounts and those of our wholly-owned and majority owned subsidiaries are included in the consolidated financial statements. All significant intercompany transactions and balances are eliminated in consolidation. The results of our European energy segment are consolidated on a one-month-lag basis due to the availability of financial information. We have made adjustments to the European energy segment's 2001 results of operations to include the effect for the settlement of an indemnity for certain energy obligations in December 2001 (see note 14(j)).

We use the equity method of accounting for investments in entities in which we have an ownership interest between 20% and 50% and exercise significant influence through representation on advisory or management committees. For our equity method accounting investments, our representation on advisory or management committees does not enable us to have majority control of the investments' management and operating decisions. The allocation of profits and losses is based on our ownership interest. For additional information regarding investments recorded using the equity method of accounting, see note 8. Other investments, excluding marketable securities, are carried at cost. For these other investments, we do not exercise significant influence. For additional information regarding these investments, see note 2(o).

In 2000, we entered into separate sale/leaseback transactions with each of the three owner-lessors for our respective interests in three power generating stations acquired in an acquisition. For additional discussion of these lease transactions, see note 14(a). We do not consolidate these generating facilities. In 2001, we, through several of our subsidiaries, entered into operative documents with special purpose entities to facilitate the development, construction, financing and leasing of several power generation projects. As of December 31, 2002, we did not consolidate these special purpose entities. For information regarding these transactions, see note 14(b). In July 2002, we entered into a receivable facility arrangement with a financial institution to sell an undivided interest in accounts receivable from residential and small commercial retail electric customers under which, on an ongoing basis, the financial institution will invest up to a maximum amount for its interest in such receivables. Pursuant to this receivables facility, we formed a qualified special purpose entity as a bankruptcy remote subsidiary. We do not consolidate this qualified special purpose entity. For additional information regarding this qualified special purpose entity, see note 15.

Each of Orion Power New York, LP (Orion NY), Orion Power New York LP, LLC, Orion Power New York GP, Inc., Astoria Generating Company, L.P., Carr Street Generating Station, LP, Erie Boulevard Hydropower, LP, Orion Power MidWest, LP (Orion MidWest), Orion Power Midwest LP, LLC, Orion Power Midwest GP, Inc., Twelvepole Creek, LLC and Orion Power Capital, LLC (Orion Capital) is a separate legal entity and has its own assets.

(d) Revenues.

We record gross revenue for energy sales and services related to our electric power generation facilities under the accrual method and these revenues generally are recognized upon delivery. Electric power and other energy services are sold at market-based prices through existing power exchanges or through third-party contracts. Energy sales and services related to our electric power generation facilities not billed by month-end are accrued based upon estimated energy and services delivered.

We record gross revenue for energy sales and services to residential, small commercial and non-contracted large commercial, industrial and institutional retail electric customers under the accrual method and these revenues generally are recognized upon delivery. Our contracted electricity sales to large commercial, industrial and institutional customers for contracts entered into after October 25, 2002 are typically accounted for under the accrual method and these revenues generally are recognized upon delivery (see note 2(t)). The determination of these sales is based on the reading of the customers' meters by the transmission and distribution utilities. The transmission and distribution utilities send the information to the Electric Reliability Council of Texas (ERCOT) Independent System Operator (ERCOT ISO), which in turn sends the information to us. This activity occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on daily forecasted volumes, estimated customer usage by class,

weather factors and applicable customer rates based on analyses reflecting significant historical trends and experience. As of December 31, 2001 and 2002, our retail energy segment had accrued unbilled revenues of $14 million and $216 million, respectively.

Our energy trading, marketing, risk management services to customers and certain power origination activities and our contracted electricity sales to large commercial, industrial and institutional customers and the related energy supply contracts for contracts entered into prior to October 25, 2002 are accounted for under the mark-to-market method of accounting. Under the mark-to-market method of accounting, derivative instruments and contractual commitments are recorded at fair value in revenues upon contract execution. The net changes in their fair values are recognized in the statements of consolidated operations as revenues in the period of change. Trading and marketing revenues related to the sale of natural gas, electric power and other energy related commodities are recorded on a net basis. For additional discussion regarding trading and marketing revenue recognition and the related estimates and assumptions that can affect reported amounts of such revenues, see note 7. For a discussion of EITF No. 02-03, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF No. 02-03) rescinding EITF No. 98-10 and the presentation of trading and marketing activities on a net basis beginning in the quarter ended September 30, 2002, see notes 2(t) and 7.

The gains and losses related to derivative instruments and contractual commitments qualifying and designated as hedges related to the purchase and sale of electric power and purchase of fuel are deferred in accumulated other comprehensive income (loss) to the extent the contracts are effective as hedges, and then are recognized in our results of operations in the same period as the settlement of the underlying hedged transactions. Realized gains and losses on financial derivatives designated as hedges are included in revenues in the statements of consolidated operations. Revenues, fuel and cost of gas sold, and purchased power related to physical sale and purchase contracts designated as hedges are generally recorded on a gross basis in the delivery period. For additional discussion, see note 7.

(e) General, Administrative and Development Expenses.

The general and administrative expenses in the statement of consolidated operations include (a) employee-related costs of the trading, marketing, power origination and risk management services operations, (b) certain contractor costs, (c) advertising, (d) materials and supplies, (e) bad debt expense, (f) marketing and market research, (g) corporate and administrative services (including management services, financial and accounting, cash management and treasury support, legal, information technology system support, office management and human resources) and (h) certain benefit costs. Some of these expenses were allocated from CenterPoint prior to the Distribution as further discussed in notes 3 and 4(a).

(f) Property, Plant and Equipment and Depreciation Expense.

We record property, plant and equipment at historical cost. We recognize repair and maintenance costs incurred in connection with planned major maintenance, such as turbine and generator overhauls, under the "accrue-in-advance" method for our power generation operations acquired or developed prior to December 31, 1999. Planned major maintenance cycles primarily range from two to ten years. Under the accrue-in-advance method, we estimate the costs of planned major maintenance and accrue the related expense over the maintenance cycle. As of December 31, 2001 and 2002, our major maintenance reserve was $19 million and $24 million, respectively, of which $2 million and $1 million, respectively, were included in other current liabilities. We expense all other repair and maintenance costs as incurred. For power generation operations acquired or developed subsequent to January 1, 2000, we expense all repair and maintenance costs as incurred, including

planned major maintenance. Depreciation is computed using the straight-line method based on estimated useful lives. Property, plant and equipment includes the following:

	Estimated Useful Lives (Years)	December 31, 2001	December 31, 2002
		(in millions)	
Electric generation facilities	10-50	$2,828	$8,163
Building and building improvements	9-32	14	24
Other	3-10	164	442
Land and land improvements		147	261
Assets under construction		1,682	677
Total		4,835	9,567
Accumulated depreciation		(276)	(626)
Property, plant and equipment, net		$4,559	$8,941

(g) Goodwill and Amortization Expense.

We record goodwill for the excess of the purchase price over the fair value assigned to the net assets of an acquisition. Through December 31, 2001, we amortized goodwill on a straight-line basis over 5 to 40 years. Pursuant to our adoption of SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142) on January 1, 2002, we discontinued amortizing goodwill into our results of operations. See note 6 for a discussion regarding our adoption of SFAS No. 142. Goodwill amortization expense was $35 million and $51 million for 2000 and 2001, respectively. The 2001 goodwill amortization expense includes a $19 million goodwill impairment related to the communications business (see note 16). Amortization expense for other intangibles, excluding contractual rights and obligations, was $44 million, $43 million and $51 million for 2000, 2001 and 2002, respectively. See also note 6.

The following table summarizes our acquisitions and the associated goodwill:

Acquisition (1)	Amortization Period (Years)(2)	December 31, 2001	December 31, 2002
		(in millions)	
Orion Power Holdings, Inc.	—	$ —	$1,324
Reliant Energy Power Generation Benelux N.V.	30	879	—
Reliant Energy Services, Inc.	40	131	131
California Generation Plants	30	70	70
Energy Services Division of Southland Industries	15	37	37
Reliant Energy Mid-Atlantic Power Holdings, LLC	35	6	7
Florida Generation Plant	35	2	2
Total		1,125	1,571
Accumulated amortization		(84)	(30)
Foreign currency exchange impact		(150)	—
Total goodwill, net		$ 891	$1,541

(1) Effective January 1, 2002, goodwill is evaluated for impairment on a reporting unit basis in accordance with SFAS No. 142 (see note 6).
(2) In accordance with SFAS No. 142, we discontinued amortizing goodwill into our results of operations effective January 1, 2002 (see note 6). The amortization periods presented relate to prior years' amortization.

We periodically evaluate long-lived assets, including goodwill and other intangibles, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred, excluding goodwill and other intangibles beginning in 2002, is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. A resulting impairment loss is highly dependent on the underlying assumptions. During 2001, we determined equipment and goodwill associated with our communications business was impaired and accordingly recognized $22 million of equipment impairments and $19 million of goodwill impairments (see note 16). In 2002, we recognized impairment charges totaling $716 million relating to our European energy segment goodwill (see note 6). During 2002, we determined that steam and combustion turbines and two heat recovery steam generators purchased in September 2002 were impaired and accordingly recognized a $37 million impairment loss (see note 14(c)). For discussion of goodwill and other intangible asset impairment analyses in 2002, see note 6.

(h) Stock-based Compensation Plans.

We apply the intrinsic method of accounting for employee stock-based compensation plans in accordance with Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB No. 25). Under the intrinsic value method, no compensation expense is recorded when options are issued with an exercise price equal to the market price of the underlying stock on the date of grant. Since our stock options have all been granted at market value at date of grant, no compensation expense has been recognized under APB No. 25. We comply with the disclosure requirements of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123) and SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure, an amendment to SFAS No. 123" (SFAS No. 148) and disclose the pro forma effect on net income (loss) and earnings (loss) per share as if the fair value method of accounting had been applied to all stock awards. Had compensation costs been determined as prescribed by SFAS No. 123, our net income (loss) and earnings (loss) per share amounts would have approximated the following pro forma results for 2000, 2001 and 2002, which take into account the amortization of stock-based compensation, including performance shares, purchases under the employee stock purchase plan and stock options, to expense on a straight-line basis over the vesting periods:

	Year Ended December 31,		
	2000	2001	2002
	(in millions, except per share amounts)		
Net income (loss), as reported	$223	$ 563	$ (560)
Add: Stock-based employee compensation expense included in reported net income/loss, net of related tax effects	4	5	2
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(7)	(34)	(38)
Pro forma net income (loss)	$220	$ 534	$ (596)
Earnings (loss) per share:			
Basic and diluted, as reported		$2.03	$(1.93)
Basic and diluted, pro forma		$1.93	$(2.05)

For further information regarding our stock-based compensation plans and our assumptions used to compute pro forma amounts, see note 12.

(i) Capitalization of Interest Expense.

Interest expense is capitalized as a component of projects under construction and is amortized over the assets' estimated useful lives. During 2000, 2001 and 2002, we capitalized interest of $35 million, $59 million and $27 million, respectively.

(j) Income Taxes.

Prior to September 30, 2002, we were included in the consolidated federal income tax returns of CenterPoint and we calculated our income tax provision on a separate return basis under a tax sharing agreement with CenterPoint. Pursuant to the tax sharing agreement with CenterPoint and agreements entered into at the time of the Distribution (see Note 4(a)), CenterPoint will owe us amounts related to certain loss carryovers, income inclusions from foreign affiliates, net income tax receivables/payables relating to our operations prior to the Distribution and other tax liabilities. Prior to September 30, 2002, current federal and some state income taxes were payable to or receivable from CenterPoint. Subsequent to the Distribution, we will file a separate federal tax return.

We use the liability method of accounting for deferred income taxes and measure deferred income taxes for all significant income tax temporary differences. Unremitted earnings from our foreign operations are deemed to be permanently reinvested in foreign operations. For additional information regarding income taxes, see note 13.

(k) Cash.

We record as cash and cash equivalents all highly liquid short-term investments with original maturities of three months or less.

(l) Restricted Cash.

Restricted cash includes cash at certain subsidiaries that is restricted by financing agreements, but is available to the applicable subsidiary to use to satisfy certain of its obligations. As of December 31, 2001 and 2002, we had $167 million and $226 million in restricted cash, respectively, recorded in the consolidated balance sheets.

The credit facilities of certain subsidiaries of Orion Power Holdings, Inc. (Orion Power) contain various covenants that include, among others, restrictions on the payment of dividends to Orion Power and us. As of December 31, 2002, restricted cash under Orion Power's subsidiaries' credit facilities totaled $200 million. For further information, see note 9(a). In addition, senior notes of Orion Power restrict its ability to pay dividends to us unless Orion Power meets certain conditions. As of December 31, 2002, the specified conditions were satisfied.

Our subsidiary, which owns an electric power generation facility in Channelview, Texas (Channelview), is party to a credit agreement used to finance construction of its generating plant. The credit agreement contains restrictive covenants that restrict Channelview's ability to, among other things, make dividend distributions unless Channelview satisfies various conditions. As of December 31, 2002, we had restricted cash of $13 million related to Channelview. As of December 31, 2001, we had no restricted cash related to Channelview. For further information regarding the Channelview credit agreement, see note 9(a).

In December 2001, our subsidiary, Reliant Energy Power Generation Benelux, N.V. (REPGB), a Dutch power generation company, and its former shareholders agreed to settle the indemnity obligations of the former shareholders insofar as they related to NEA B.V. (NEA), formerly the coordinating body for the Dutch electricity sector. Under the settlement agreement, the former shareholders of REPGB paid REPGB approximately $202 million in the first quarter of 2002. REPGB deposited the settlement payment into an escrow account, withdrawals from which are at the discretion of REPGB for use in discharging certain stranded cost obligations. As of December 31, 2002, the remaining escrowed funds totaled $6 million, which are recorded in restricted cash.

As of December 31, 2001, we have recorded $167 million of restricted cash that is available for Reliant Energy Mid-Atlantic Power Holdings, LLC and its subsidiaries' (collectively, REMA) working capital needs and for it to make future lease payments. As of December 31, 2002, we had no restricted cash related to REMA. For additional discussion regarding REMA's lease transactions, see note 14(a).

As of December 31, 2002, we had $7 million in long-term restricted cash pledged to secure the payment and performance when due related to the issuance of surety bonds. In the event of default with regard to the surety bonds, the issuer could request payment of the restricted cash from us. As of December 31, 2001, we had no restricted cash of this nature.

(m) Allowance for Doubtful Accounts.

Accounts and notes receivable, principally from customers, in the consolidated balance sheets are net of an allowance for doubtful accounts of $90 million and $69 million at December 31, 2001 and 2002, respectively. The net provision for doubtful accounts in the statements of consolidated operations for 2000, 2001 and 2002 was $43 million, $38 million and $21 million (net of $62 million in credit reserves reversed in 2002), respectively. These amounts exclude items written off during the years related to refunds for energy sales in California and related to Enron Corp. and its affiliates (Enron). For more information regarding the provisions against receivable balances related to energy sales in the California market and to Enron, see notes 14(i) and 17, respectively.

(n) Inventory.

Inventory consists of materials and supplies, coal, natural gas and heating oil. Inventories used in the production of electricity are valued at the lower of average cost or market. Heating oil and natural gas used in the trading and marketing operations are accounted for under mark-to-market accounting through December 31, 2002, as discussed in note 7. However, as discussed in note 2(t), inventory purchased after October 25, 2002 and effective January 1, 2003, inventory used in the trading and marketing operations is no longer marked to market in accordance with EITF No. 02-03. Below is a detail of inventory:

	December 31, 2001	December 31, 2002
	(in millions)	
Materials and supplies	$ 65	$136
Coal	35	59
Natural gas	41	78
Heating oil	33	46
Total inventory	$174	$319

(o) Investments.

As of December 31, 2001 and 2002, we held marketable equity securities of $12 million and $3 million, respectively, classified as "available-for-sale." In accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), we report "available-for-sale" securities at estimated fair value in other long-term assets in the consolidated balance sheets and any unrealized gain or loss, net of tax, as a separate component of stockholders' equity and accumulated other comprehensive loss. At December 31, 2001 and 2002, we had an accumulated unrealized gain, net of tax, relating to these securities of $6 million and $1 million, respectively.

During 2000, pursuant to SFAS No. 115, we incurred a pre-tax impairment loss equal to the $27 million of cumulative unrealized losses that had been charged to accumulated other comprehensive loss through December 31, 1999. Management's decision to recognize this impairment resulted from a combination of events occurring in 2000 related to this investment. These events affecting the investment included changes occurring in the investment's senior management, announcement of significant restructuring charges and related downsizing for the entity, reduced earnings estimates for this entity by brokerage analysts and the bankruptcy of a competitor of the investment in the first quarter of 2000. These events, coupled with the stock market value of our investment in these securities continuing to be below our cost basis, caused management to believe the decline in fair value of these "available-for-sale" securities to be other than temporary.

In addition, we held debt and equity securities classified as "trading." In accordance with SFAS No. 115, we report "trading" securities at estimated fair value in our consolidated balance sheets and any unrealized holding gains and losses are recorded as gains (losses) from investments in the statements of consolidated operations. As of December 31, 2001, we held equity securities classified as "trading" totaling $1 million. As of December 31, 2002, we no longer hold equity securities classified as "trading." We recorded unrealized holding gains on "trading" securities included in gains from investments in the statements of consolidated operations of $4 million and $5 million during 2000 and 2001, respectively. During 2002, the recorded unrealized holding gain on "trading" securities included in losses from investments in the statements of consolidated operations was less than $1 million.

As of December 31, 2001 and 2002, we have other investments of $68 million and $44 million, respectively, excluding marketable securities, in which we have ownership interests of 20% or less and do not exercise significant influence, which are carried at cost. During 2002, we incurred a pre-tax impairment loss of $32 million ($30 million after-tax) related to these investments. Management's decision to recognize these impairments resulted from a combination of events occurring in 2002 related to these investments. These events included reduced cash flow expectations for certain of these investments and management's decision to minimize further financial support to these investments. These events, coupled with management's intent to sell certain investments in the near-term below our cost basis, led us to believe the decline in the fair value of these investments was other than temporary.

(p) Project Development Costs.

Project development costs include costs for professional services, permits and other items that are incurred incidental to a particular project. We expense these costs as incurred until the project is considered probable. After a project is considered probable, subsequent capitalizable costs incurred are capitalized to the project. When project operations begin, we begin to amortize these costs on a straight-line basis over the life of the facility. As of December 31, 2001 and 2002, we had recorded in the consolidated balance sheets project development costs associated with projects under construction of $9 million and $6 million, respectively.

(q) Environmental Costs.

We expense or capitalize environmental expenditures, as appropriate, depending on their future economic benefit. We expense amounts that relate to an existing condition caused by past operations and that do not have future economic benefit. We record undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

(r) Deferred Financing Costs.

Deferred financing costs are costs incurred in connection with obtaining financings. These costs are deferred and amortized, using the straight-line method, which approximates the effective interest method, over the life of the related debt. As of December 31, 2001 and 2002, we had $8 million and $44 million, respectively, of net deferred financing costs capitalized in our consolidated balance sheets.

(s) Foreign Currency Adjustments.

Local currencies are the functional currency of our foreign operations. Foreign subsidiaries' assets and liabilities have been translated into U.S. dollars using the exchange rate at the balance sheet date. Revenues, expenses, gains and losses have been translated using the weighted average exchange rate for each month prevailing during the periods reported. Cumulative adjustments resulting from translation have been recorded as a component of accumulated other comprehensive loss in stockholders' equity.

(t) Changes in Accounting Principles and New Accounting Pronouncements.

SFAS No. 141. In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141 "Business Combinations" (SFAS No. 141). SFAS No. 141 requires business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting and broadens the criteria for recording intangible assets separate from goodwill. Recorded goodwill and intangibles will be evaluated against these new criteria and may result in certain intangibles being transferred to goodwill, or alternatively, amounts initially recorded as goodwill may be separately identified and recognized apart from goodwill. We adopted the provisions of the statement, which apply to goodwill and intangible assets acquired prior to June 30, 2001 on January 1, 2002. The adoption of SFAS No. 141 did not have a material impact on our historical results of operations or financial position.

SFAS No. 142. See note 6 for a discussion regarding our adoption of SFAS No. 142 on January 1, 2002.

SFAS No. 143. In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 requires the fair value of a liability for an asset retirement legal obligation to be recognized in the period in which it is incurred. When the liability is initially recorded, associated costs are capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. SFAS No. 143 requires entities to record a cumulative effect of a change in accounting principle in the statement of operations in the period of adoption. We are currently evaluating the impact of SFAS No. 143 on our consolidated financial statements and expect to record a cumulative effect of a change in accounting principle of a net gain.

SFAS No. 144. In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). SFAS No. 144 provides new guidance on the recognition of impairment losses on long-lived assets to be held and used or to be disposed of and also broadens the definition of what constitutes a discontinued operation and how the results of a discontinued operation are to be measured and presented. SFAS No. 144 supercedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," and Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions," while retaining many of the requirements of these two statements. Under SFAS No. 144, assets held for sale that are a component of an entity will be included in discontinued operations if the operations and cash flows will be or have been eliminated from the ongoing operations of the entity and the entity will not have any significant continuing involvement in the operations prospectively. SFAS No. 144 did not materially change the methods used by us to measure impairment losses on long-lived assets, but may result in additional future dispositions being reported as discontinued operations. We adopted SFAS No. 144 on January 1, 2002.

SFAS No. 145. In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS No. 145). SFAS No. 145 eliminates the current requirement that gains and losses on debt extinguishment must be classified as extraordinary items in the statement of operations. Instead, such gains and losses will be classified as extraordinary items only if they are deemed to be unusual and infrequent. SFAS No. 145 also requires sale-leaseback accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The changes related to debt extinguishment will be effective for fiscal years beginning after May 15, 2002, and the changes related to lease accounting are effective for transactions occurring after May 15, 2002. We will apply this guidance prospectively.

SFAS No. 148. In December 2002, the FASB issued SFAS No. 148. This statement provides alternative methods of transition for a company that voluntarily changes to the fair value method of accounting for stock-based employee compensation. SFAS No. 148 also amends disclosure requirements of SFAS No. 123 to require prominent disclosure in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS No. 148 is effective for annual financial statements for fiscal years ending after December 15, 2002 and condensed financial statements for interim periods beginning after December 15, 2002. Currently, we are evaluating if we will voluntarily change to the fair value method of accounting for stock-based employee compensation in the future. We have adopted the disclosure requirements of SFAS No. 148 for the consolidated financial statements for 2002 (see note 12(a)).

FIN No. 45. In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Direct Guarantees of Indebtedness of Others," (FIN No. 45) which increases the disclosure requirements for a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It clarifies that a guarantor's required disclosures include the nature of the guarantee, the maximum potential undiscounted payments that could be required, the current carrying amount of the liability, if any, for the guarantor's obligations (including the liability recognized under SFAS No. 5, "Accounting for Contingencies"), and the nature of any recourse provisions or available collateral that would enable the guarantor to recover amounts paid under the guarantee. It also requires a guarantor to recognize, at the inception of a guarantee issued after December 31, 2002, a liability for the fair value of the obligation undertaken in issuing the guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that specified triggering events or conditions occur. We have

adopted the disclosure requirements of FIN No. 45 for 2002 (see note 14(g)) and will apply the initial recognition and initial measurement provisions on a prospective basis for all guarantees issued after December 31, 2002. The adoption of FIN No. 45 will have no impact to our historical consolidated financial statements, as existing guarantees are not subject to the measurement provisions. We are currently evaluating the impact of FIN No. 45's initial recognition and measurement provisions on our consolidated financial statements.

FIN No. 46. In January 2003, the FASB issued FASB Interpretation No. 46 "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51" (FIN No. 46). The objective of FIN No. 46 is to achieve more consistent application of consolidation policies to variable interest entities and to improve comparability between enterprises engaged in similar activities. FIN No. 46 states that an enterprise must consolidate a variable interest entity if the enterprise has a variable interest that will absorb a majority of the entity's expected losses if they occur, receives a majority of the entity's expected residual returns if they occur, or both. If one enterprise absorbs a majority of a variable interest entity's expected losses and another enterprise receives a majority of that entity's expected residual returns, the enterprise absorbing a majority of the losses shall consolidate the variable interest entity and will be called the primary beneficiary. FIN No. 46 is effective immediately to variable interest entities created after January 31, 2003, and to variable interest entities in which an enterprise obtains an interest after that date. For enterprises that acquired variable interests prior to February 1, 2003, the effective date is for fiscal years or interim periods beginning after June 15, 2003. FIN No. 46 requires entities to either (a) record the effects prospectively with a cumulative effect adjustment as of the date on which FIN No. 46 is first applied or (b) restate previously issued financial statements for the years with a cumulative effect adjustment as of the beginning of the first year being restated. We have elected to early adopt FIN No. 46 and are currently evaluating the adoption impact as it relates to a cumulative effect of a change in accounting principle on January 1, 2003.

Based on our preliminary analysis, we believe that we have variable interests in three power generation projects that are being constructed by off-balance sheet special purpose entities under construction agency agreements as of December 31, 2002, which pursuant to this guidance would require consolidation effective January 1, 2003. As of December 31, 2002, these special purpose entities had property, plant and equipment of $1.3 billion, net other assets of $3 million and debt obligations of $1.3 billion. As of December 31, 2002, the special purpose entities had equity from unaffiliated third parties of $49 million. These special purpose entities' financing agreement, the construction agency agreements and the related guarantees were terminated as part of the refinancing in March 2003. For information regarding these special purpose entities and the refinancing, see notes 14(b) and 21(a).

We do not expect the adoption of FIN No. 46 to have a material impact on our results of operations or financial position, excluding the consolidation of the entities under the construction agency agreements as discussed above.

EITF No. 02-03. In June 2002, the EITF had its initial meeting regarding EITF No. 02-03 and reached a consensus that all mark-to-market gains and losses on energy trading contracts should be shown net in the statement of operations whether or not settled physically. In October 2002, the EITF issued a consensus that superceded the June 2002 consensus. The October 2002 consensus required, among other things, that energy derivatives held for trading purposes be shown net in the statement of operations. This new consensus is effective for fiscal periods beginning after December 15, 2002. However, consistent with the new consensus and as allowed under EITF No. 98-10, beginning with the quarter ended September 30, 2002, we now report all energy trading and marketing activities on a net basis in the statements of consolidated operations. Comparative financial statements for prior periods have been reclassified to conform to this presentation.

The adoption of net reporting resulted in reclassifications of revenues, fuel and cost of gas sold, purchased power expense during 2000 and 2001 as follows:

	Year Ended December 31,			
	2000		2001	
	As Reclassified	As Previously Reported	As Reclassified	As Previously Reported
	(in millions)			
Revenues	$3,255	$18,722	$6,122	$31,130
Trading margins	200	–	369	–
Total	3,455	18,722	6,491	31,130
Fuel and cost of gas sold	1,172	10,555	1,975	15,234
Purchased power	925	6,809	2,509	13,889
Other operating expenses	920	920	1,245	1,245
Total	3,017	18,284	5,729	30,368
Operating income	$ 438	$ 438	$ 762	$ 762

Furthermore, in October 2002, under EITF No. 02-03, the EITF reached a consensus to rescind EITF No. 98-10. All new contracts that would have been accounted for under EITF No. 98-10, and that do not fall within the scope of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133) should no longer be marked-to-market through earnings beginning October 25, 2002. In addition, mark-to-market accounting is no longer applied to inventories used in the trading and marketing operations. This transition is effective for us for the first quarter of 2003. We expect to record a cumulative effect of a change in accounting principle of approximately $40 million loss, net of tax, effective January 1, 2003, related to EITF No. 02-03.

The EITF has not reached a consensus on whether recognition of dealer profit or unrealized gains and losses at inception of an energy trading contract is appropriate in the absence of quoted market prices or current market transactions for contracts with similar terms. In the June 2002 EITF meeting and again in the October 2002 EITF meeting, the FASB staff indicated that until such time as a consensus is reached, the FASB staff will continue to hold the view that previous EITF consensuses do not allow for recognition of dealer profit, unless evidenced by quoted market prices or other current market transactions for energy trading contracts with similar terms and counterparties. During 2001 and 2002, we recorded $119 million and $57 million, respectively, of fair value at the contract inception related to trading and marketing activities. Inception gains recorded were evidenced by quoted market prices and other current market transactions for energy trading contracts with similar terms and counterparties.

(3) RELATED PARTY TRANSACTIONS

The consolidated financial statements include significant transactions between CenterPoint and us. The disclosures within this note are for these transactions for 2000, 2001 and the nine months ended September 30, 2002, up to the date of the Distribution. Some of these transactions involve services, including various corporate support services (including accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs and human resources), information technology services and other shared services such as corporate security, facilities management, accounts receivable, accounts payable and payroll,

office support services and purchasing and logistics. The costs of services have been directly charged or allocated to us using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment, and proportionate corporate formulas based on assets, operating expenses and employees. These charges and allocations are not necessarily indicative of what would have been incurred had we been an unaffiliated entity. Amounts charged and allocated to us for these services were $34 million, $9 million and $15 million for 2000, 2001 and the nine months ended September 30, 2002, respectively, and are included primarily in operation and maintenance expenses and general and administrative expenses. In addition, during 2001, we incurred costs of $27 million primarily related to corporate support services, which were billed to CenterPoint and its affiliates. Some of our subsidiaries have entered into office rental agreements with CenterPoint. During 2000, 2001 and the nine months ended September 30, 2002, we incurred $4 million, $16 million and $24 million, respectively, of rent expense to CenterPoint.

Certain of these services and the office space lease arrangements between CenterPoint and us continue after the Distribution under transition service agreements or other long-term agreements. It is not anticipated that a change, if any, in these costs and revenues will have a material effect on our consolidated results of operations, cash flows or financial position. For additional information regarding these services and office space lease arrangements between CenterPoint and us, see note 4(a).

Below is a detail of accounts and notes receivable to affiliated companies as of December 31, 2001 (in millions):

Net accounts receivable—affiliated companies	$ 27
Net short-term notes receivable—affiliated companies	388
Net long-term notes receivable—affiliated companies	30
Total net accounts and notes receivable—affiliated companies	$445

Net accounts receivable—affiliated companies, representing primarily current month balances of transactions between us and CenterPoint or its subsidiaries, related primarily to natural gas purchases and sales, interest, charges for services and office space rental. Net short-term notes receivable—affiliated companies represented the accumulation of a variety of cash transfers and operating transactions and specific negotiated financing transactions with CenterPoint or its subsidiaries and generally bore interest at market-based rates. Net long-term notes receivable—affiliated companies primarily related to a specific negotiated financing transaction with a subsidiary of CenterPoint, see note 14(f). Net interest expense related to these net borrowings/receivables was $172 million during 2000. Net interest income related to these net borrowings/receivables was $12 million and $5 million during 2001 and the nine months ended September 30, 2002, respectively.

In May 2001, CenterPoint converted or contributed an aggregate of $1.7 billion of our indebtedness to CenterPoint and its subsidiaries to equity without the issuance of any additional shares of our common stock, pursuant to the terms of a master separation agreement between CenterPoint and us (Master Separation Agreement), by recording an increase to our additional paid-in capital. In addition, we used $147 million of the net proceeds of the IPO to repay certain indebtedness owed to CenterPoint in May 2001.

During 2001 and the first half of 2002, proceeds not initially utilized from the IPO were advanced to a subsidiary of CenterPoint (the CenterPoint money fund) on a short-term basis. We reduced our advance to the CenterPoint money fund following the IPO to fund capital expenditures and to meet our working capital needs. As of December 31, 2001, we had outstanding advances to the CenterPoint money fund of $390 million, which is included in accounts and notes receivable in our consolidated balance sheet.

We purchased natural gas, natural gas transportation services, electric generation energy and capacity, and electric transmission services from, supplied natural gas to, and provided marketing and risk management services to affiliates of CenterPoint. Purchases and sales related to our trading and marketing activities are recorded net in trading margins in the statements of consolidated operations. During 2000 and 2001, there were no material purchases of electric generation energy and capacity and electric transmission services from CenterPoint and its subsidiaries. Purchases of electric generation energy and capacity and electric transmission services from CenterPoint and its subsidiaries were $1.5 billion in the nine months ended September 30, 2002. During 2000, 2001 and the nine months ended September 30, 2002, the net purchases and sales and services from/to CenterPoint and its subsidiaries related to our trading and marketing operations totaled $405 million, $469 million and $161 million, respectively. In addition, during 2000, 2001 and the nine months ended September 30, 2002, other sales and services to CenterPoint and its subsidiaries totaled $23 million, $56 million and $15 million, respectively. Sales and purchases to/from CenterPoint subsequent to the Distribution are not reported as affiliated transactions.

During 2001, REPGB received efficiency and energy payments from NEA, an equity investment, totaling $30 million pursuant to a protocol agreement under which the Dutch generators provided capacity and energy to distributors in exchange for regulated production payments. In addition, during 2001 REPGB received payments from NEA totaling $14 million related to environmental tax subsidies for previous periods.

During 2001 and 2002, we purchased entitlements to some of the generation capacity of electric generation assets of Texas Genco, LP (Texas Genco), a subsidiary of CenterPoint. We purchased these entitlements in capacity auctions conducted by Texas Genco and pursuant to rights granted to us under the Master Separation Agreement, see note 4(b). As of December 31, 2002, we had purchased entitlements to capacity of Texas Genco averaging 5,865 MW per month in 2003. Our anticipated capacity payments related to these capacity entitlements are $336 million in 2003. During the first quarter of 2003, through March 20, 2003, we purchased additional entitlements to some of the generation capacity of electric generation assets of Texas Genco averaging 879 MW per month for 2003 with capacity payments of $84 million. For additional information regarding agreements relating to Texas Genco, see note 4(b).

During 2000, 2001 and the nine months ended September 30, 2002, CenterPoint made equity contributions to us of $1.4 billion, $1.8 billion and $21 million, respectively. For the three months ended December 31, 2002, we recorded equity contributions to us from CenterPoint of $26 million, which CenterPoint funded in January 2003, for a total of $47 million during 2002. The contributions received by us in 2000 primarily related to (a) conversion of $1 billion of the borrowings from CenterPoint used to fund the acquisition of REMA (see note 5(b)), (b) the forgiveness of $284 million of debt held by subsidiaries that were transferred from RERC Corp. to us (see note 1) and (c) general operating costs. The contributions in 2001 primarily related to the conversion into equity of debt owed to CenterPoint and some related interest expense totaling $1,7 billion and the contribution of net benefit assets and liabilities, net of deferred income taxes. The contributions in 2002 primarily related to benefit obligations, net of deferred income taxes, pursuant to the Master Separation Agreement.

(4) AGREEMENTS BETWEEN CENTERPOINT AND US

(a) Transition Agreements.

We entered into various written agreements with CenterPoint that were required to facilitate an orderly separation of our businesses and operations from those of CenterPoint in contemplation of our IPO and the Distribution. The agreements, which are described below, address, among other things, the provision of certain services and the leasing of facilities on an interim basis, as well as the allocation of certain liabilities and obligations.

CenterPoint has agreed to provide us various corporate support services, information technology services and other previously shared services such as corporate security, facilities management, accounts receivable, accounts payable and payroll, office support services and purchasing and logistics services. Certain of these arrangements will continue until December 31, 2004; however, we have the right to terminate categories of services at an earlier date. The charges we pay to CenterPoint for these services allow CenterPoint to recover its fully allocated costs of providing the services, plus out-of-pocket costs and expenses. It is not anticipated that termination of any these arrangements will have a material effect on our business, results of operations, financial condition or cash flows.

We agreed to provide CenterPoint customer service call center operations, credit and collection and revenue accounting services for CenterPoint's electric utility division, and receiving and processing payment services for the accounts of CenterPoint's electric utility division and two of CenterPoint's natural gas distribution divisions. CenterPoint provided the office space and equipment for us to perform these services. The charges CenterPoint paid us for these services allowed us to recover our fully allocated costs of providing the services, plus out-of-pocket costs and expenses. As of December 31, 2001, we no longer provide these services to CenterPoint.

We lease office space in CenterPoint's corporate headquarters and in various other CenterPoint facilities in Houston, Texas. Our lease on our corporate headquarters primarily expires in January 2004. We also have various agreements with CenterPoint relating to ongoing commercial arrangements, including the leasing of optical fiber and related maintenance activities, gas purchasing and agency matters and subcontracting energy services under existing contracts.

We have agreements with CenterPoint providing for mutual indemnities and releases with respect to our respective businesses and operations, corporate governance matters, the responsibility for employee compensation and benefits, and the allocation of tax liabilities. The agreements also require us to indemnify CenterPoint for any untrue statement of a material fact, or omission of a material fact necessary to make any statement not misleading, in the registration statement or prospectus that we filed with the SEC in connection with our IPO. We have also guaranteed, in the event CenterPoint becomes insolvent, certain non-qualified benefits of CenterPoint's and its subsidiaries' existing retirees at the Distribution totaling approximately $58 million.

(b) Agreements Relating to Texas Genco.

Texas Genco owns the Texas generating assets formerly held by CenterPoint's electric utility division. Texas Genco, as the affiliated power generator of CenterPoint, is required by law to sell at auction 15% of the output of its installed generating capacity. These auction obligations will continue until January 2007, unless at least 40% of the electricity consumed by residential and small commercial customers in CenterPoint's service territory is being served by retail electric providers other than us. Texas Genco has agreed to auction all of its capacity that remains subsequent to the capacity auctioned mandated under PUCT rules and after certain other adjustments. We have the right to purchase 50% (but not less than 50%) of such remaining capacity at the prices established in such auctions. We also have the right to participate directly in such auctions. Texas Genco's obligation to auction its capacity and our associated rights terminate (a) if we do not exercise our option to acquire CenterPoint's ownership interest in Texas Genco by January 24, 2004 and (b) if we exercise our option to acquire CenterPoint's ownership interest in Texas Genco, on the earlier of (i) the closing of the acquisition or (ii) if the closing has not occurred, the last day of the sixteenth month after the month in which the option is exercised. For a discussion of our purchases of capacity from Texas Genco in 2001 and 2002, see note 3.

In January 2003, CenterPoint distributed approximately 19% of the common stock of Texas Genco. CenterPoint has granted us an option to purchase all of the remaining shares of common stock of Texas Genco

held by CenterPoint. We may exercise the option between January 10, 2004 and January 24, 2004. The per share exercise price under the option will be the average daily closing price on the national exchange for publicly held shares of common stock of Texas Genco for the 30 consecutive trading days with the highest average closing price during the 120 trading days immediately preceding January 9, 2004, plus a control premium, up to a maximum of 10%, to the extent a control premium is included in the valuation determination made by the PUCT. The exercise price is also subject to adjustment based on the difference between the per share dividends paid during the period there is a public ownership interest in Texas Genco and Texas Genco's per share earnings during that period. We have agreed that if we exercise the Texas Genco option, we will also purchase all notes and other receivables from Texas Genco then held by CenterPoint, at their principal amount, plus accrued interest. Similarly, if Texas Genco holds notes or receivables from CenterPoint, we will assume CenterPoint's obligations in exchange for a payment to us by CenterPoint of an amount equal to the principal, plus accrued interest.

We have entered into a support agreement with CenterPoint, pursuant to which we provide engineering and technical support services and environmental, safety and industrial health services to support operations and maintenance of Texas Genco's facilities. We also provide systems, technical, programming and consulting support services and hardware maintenance (but excluding plant-specific hardware) necessary to provide dispatch planning, dispatch and settlement and communication with the independent system operator. The fees we charge for these services are designed to allow us to recover our fully allocated direct and indirect costs and reimbursement of out-of-pocket expenses. Expenses associated with capital investment in systems and software that benefit both the operation of Texas Genco's facilities and our facilities in other regions are allocated on an installed MW basis. The term of this agreement will end on the first to occur of (a) the closing date of our acquisition of Texas Genco under the option, (b) CenterPoint's sale of Texas Genco, or all or substantially all of the assets of Texas Genco, if we do not exercise the Texas Genco option, or (c) May 31, 2005 if we do not exercise the option; however, Texas Genco may extend the term of this agreement until December 31, 2005.

On October 1, 2002, we entered into a master power purchase contract with Texas Genco covering, among other things, our purchases of capacity and/or energy from Texas Genco's generating units, under an unsecured line of credit. This contract contains covenants that restrict the activities of several of our retail energy segment's subsidiaries. These restrictions include limitations on the ability of these subsidiaries to (a) sell assets (including customers); (b) consolidate or merge with other companies, including affiliated companies outside the retail energy segment; (c) grant liens on their properties (other than permitted liens); (d) borrow money in excess of agreed upon levels (other than securitizations of customer accounts); (e) enter into or guarantee certain trading arrangements; and (f) incur liabilities outside the ordinary course of their businesses. In addition, there are restrictions involving transactions with affiliated companies outside the retail energy segment. The primary term of this contract ends on December 31, 2003.

(5) BUSINESS ACQUISITIONS

(a) Orion Power Holdings, Inc.

In February 2002, we acquired all of the outstanding shares of common stock of Orion Power for an aggregate purchase price of $2.9 billion and assumed debt obligations of $2.4 billion. We funded the Orion Power acquisition with a $2.9 billion credit facility (see note 9(a)) and $41 million of cash on hand. As a result of the acquisition, our consolidated debt obligations also increased by the amount of Orion Power's debt obligations. As of February 19, 2002, Orion Power's debt obligations were $2.4 billion ($2.1 billion net of restricted cash pursuant to debt covenants). Orion Power is an electric power generating company with a diversified portfolio of generating assets, both geographically across the states of New York, Pennsylvania, Ohio

and West Virginia, and by fuel type, including gas, oil, coal and hydro. The primary reason for the acquisition was to enhance our then current domestic power generation position by combining our domestic generation capacity and Orion Power's domestic generation capacity. The Orion Power acquisition expanded our market presence into the New York and East Central Area Reliability Coordinating Counsel power markets. As of February 19, 2002, Orion Power had 81 generating facilities with a total generating capacity of 5,644 MW and two development projects with an additional 804 MW of capacity under construction. As of December 31, 2002, both projects under construction had reached commercial operation.

We accounted for the acquisition as a purchase with assets and liabilities of Orion Power reflected at their estimated fair values. Our fair value adjustments primarily included adjustments in property, plant and equipment, contracts, severance liabilities, debt, unrecognized pension and postretirement benefits liabilities and related deferred taxes. We finalized these fair value adjustments in February 2003, based on final valuations of property, plant and equipment, intangible assets and other assets and obligations. There were no additional material modifications to the preliminary adjustments from December 31, 2002.

The net purchase price of Orion Power was allocated and the fair value adjustments to the seller's book value were as follows:

	Purchase Price Allocation	Fair Value Adjustments
	(in millions)	
Current assets	$ 636	$ (8)
Property, plant and equipment	3,823	519
Goodwill	1,324	1,220
Other intangibles	477	282
Other long-term assets	103	34
Total assets acquired	6,363	2,047
Current liabilities	(1,777)	(51)
Current contractual obligations	(29)	(29)
Long-term contractual obligations	(86)	(86)
Long-term debt	(1,006)	(45)
Other long-term liabilities	(501)	(396)
Total liabilities assumed	(3,399)	(607)
Net assets acquired	$ 2,964	$1,440

Adjustments to property, plant and equipment and other intangibles, excluding contractual rights, are based primarily on valuation reports prepared by independent appraisers and consultants.

The following factors contributed to the recognized goodwill of $1.3 billion: commercialization value attributable to our marketing and trading capabilities, commercialization and synergy value associated with fuel procurement in conjunction with existing generating plants in the region, entry into the New York power market, general and administrative cost synergies with existing Pennsylvania–New Jersey–Maryland power market generating assets and headquarters, and risk diversification value due to increased scale, fuel supply mix and the nature of the acquired assets. Of the resulting goodwill, all but $105 million is not deductible for United States income tax purposes. The $1.3 billion of goodwill was assigned to the wholesale energy segment.

The components of other intangible assets and the related weighted-average amortization period for the Orion Power acquisition consist of the following:

	Purchase Price Allocation	Weighted-Average Amortization Period (Years)
	(in millions)	
Air emission regulatory allowances	$314	38
Contractual rights	106	8
Federal Energy Regulatory Commission (FERC) licenses	57	38
Total	$477	

There was no allocation of purchase price to any intangible assets that are not subject to amortization.

Our results of operations include the results of Orion Power for the period beginning February 19, 2002. The following table presents selected financial information and unaudited pro forma information for 2001 and 2002, as if the acquisition had occurred on January 1, 2001 and 2002, as applicable:

	Year Ended December 31,			
	2001		2002	
	Actual	Pro forma	Actual	Pro forma
	(in millions, except per share amounts)			
Revenues	$6,499	$7,655	$11,558	$11,665
Income (loss) before cumulative effect of accounting change	560	604	(326)	(390)
Net income (loss)	563	607	(560)	(624)
Basic and diluted earnings (loss) per share before cumulative effect of accounting change	$ 2.02	$ 2.18	$ (1.12)	$ (1.34)
Basic and diluted earnings (loss) per share	2.03	2.19	(1.93)	(2.15)

These unaudited pro forma results, based on assumptions we deem appropriate, have been prepared for informational purposes only and are not necessarily indicative of the amounts that would have resulted if the acquisition of Orion Power had occurred on January 1, 2001 and 2002, as applicable. Purchase-related adjustments to the results of operations include the effects on revenues, fuel expense, depreciation and amortization, interest expense, interest income and income taxes. Adjustments that affected revenues and fuel expense were a result of the amortization of contractual rights and obligations relating to the applicable power and fuel contracts that were in existence at January 1, 2001 or January 1, 2002, as applicable. Such amortization included in the pro forma results above was based on the value of the contractual rights and obligations at February 19, 2002. The amounts applicable to 2002 were retroactively applied to January 1, 2002 through February 19, 2002 and the year ended December 31, 2001, to arrive at the pro forma effect on those periods. The unaudited pro forma condensed consolidated financial statements reflect the acquisition of Orion Power in accordance with SFAS No. 141 and SFAS No. 142. For additional information regarding our adoption of SFAS No. 141 and SFAS No. 142, see notes 2(t) and 6.

(b) Reliant Energy Mid-Atlantic Power Holdings, LLC.

On May 12, 2000, one of our subsidiaries purchased entities owning electric power generating assets and development sites located in Pennsylvania, New Jersey and Maryland having an aggregate net generating

capacity of approximately 4,262 MW. With the exception of development entities that were sold to another subsidiary in July 2000, the assets of the entities acquired are held by REMA. The purchase price for the May 2000 transaction was $2.1 billion. In 2002, we made an $8 million payment to the prior owner for post-closing adjustments, which resulted in an adjustment to the purchase price. We accounted for the acquisition as a purchase with assets and liabilities of REMA reflected at their estimated fair values. Our fair value adjustments related to the acquisition primarily included adjustments in property, plant and equipment, air emissions regulatory allowances, specific intangibles, materials and supplies inventory, environmental reserves and related deferred taxes. The air emissions regulatory allowances of $153 million are being amortized on a units-of-production basis as utilized. The specific intangibles that relate to water rights and permits of $43 million will be amortized over the estimated life of the related facility of 35 years. The excess of the purchase price over the fair value of the net assets acquired of $7 million was recorded as goodwill and was amortized over 35 years through December 31, 2001. See note 6 regarding the cessation of goodwill amortization. We finalized these fair value adjustments in May 2001. There were no additional material modifications to the preliminary adjustments from December 31, 2000. Funds for the acquisition of REMA were made available through loans from CenterPoint. In May 2000, $1.0 billion of these loans were subsequently converted to equity.

The net purchase price of REMA was allocated and the fair value adjustments to the seller's book value are as follows:

	Purchase Price Allocation	Fair Value Adjustments
	(In millions)	
Current assets	$ 85	$ (27)
Property, plant and equipment	1,898	627
Goodwill	7	(144)
Other intangibles	196	33
Other long-term assets	3	(5)
Total assets acquired	2,189	484
Current liabilities	(50)	(13)
Other long-term liabilities	(39)	(15)
Total liabilities assumed	(89)	(28)
Net assets acquired	$2,100	$ 456

Adjustments to property, plant and equipment, other intangibles, which include air emissions regulatory allowances, and other specific intangibles, and environmental reserves included in other liabilities are based primarily on valuation reports prepared by independent appraisers and consultants.

In August 2000, we entered into separate sale-leaseback transactions with each of three owner-lessors covering our respective 16.45%, 16.67% and 100% interests in the Conemaugh, Keystone and Shawville generating stations, respectively, acquired as part of the REMA acquisition. As lessee, we lease an interest in each facility from each owner-lessor under a leveraged facility lease agreement. As consideration for the sale of our interest in the facilities, we received $1.0 billion in cash. We used the $1.0 billion of sale proceeds to repay intercompany indebtedness owed by us to CenterPoint.

Our results of operations include the results of REMA for the period beginning May 12, 2000. The following table presents selected actual financial information and unaudited pro forma information for 2000, as if

the acquisition had occurred on January 1, 2000. Pro forma amounts also give effect to the sale and leaseback of interests in three REMA generating plants discussed above.

	Year Ended December 31, 2000	
	Actual	Pro forma
	(in millions)	
Revenues	$3,475	$3,641
Income before extraordinary item	216	207
Net income	223	214

These unaudited pro forma results, based on assumptions deemed appropriate by our management, have been prepared for informational purposes only and are not necessarily indicative of the amounts that would have resulted if the acquisition of the REMA entities had occurred on January 1, 2000. Purchase-related adjustments to the results of operations include the effects on depreciation and amortization, interest expense and income taxes.

(c) Reliant Energy Power Generation Benelux N.V.

Effective October 7, 1999, we acquired REPGB, a Dutch electric generation company, for a total net purchase price, payable in Dutch Guilders (NLG), of $1.9 billion based on an exchange rate on October 7, 1999 of 2.06 NLG per U.S. dollar. The aggregate purchase price paid in 1999 by us consisted of $833 million in cash. On March 1, 2000, under the terms of the acquisition agreement, we funded the remaining purchase obligation for $982 million. A portion of this obligation ($596 million) was financed with a three-year term loan facility obtained in the first quarter of 2000 (see note 9(a)). We recorded the REPGB acquisition under the purchase method of accounting, with assets and liabilities of REPGB reflected at their estimated fair values.

(6) GOODWILL AND INTANGIBLES

In July 2001, the FASB issued SFAS No. 142, which states that goodwill and certain intangibles with indefinite lives will not be amortized into results of operations, but instead will be reviewed periodically for impairment and written down and charged to results of operations only in the periods in which the recorded value of goodwill and certain intangibles with indefinite lives is more than their fair values. We adopted the provisions of the statement, which apply to goodwill and intangible assets acquired prior to June 30, 2001 on January 1, 2002, and thus discontinued amortizing goodwill into our results of operations. A reconciliation of previously reported net income (loss) and earnings (loss) per share to the amounts adjusted for the exclusion of goodwill amortization follows:

	Year Ended December 31,		
	2000	2001	2002
	(in millions, except per share amounts)		
Reported net income (loss)	$223	$ 563	$ (560)
Add: Goodwill amortization, net of tax	35	51	—
Less: Goodwill impairment relating to exiting communications business (1)	—	(19)	—
Adjusted net income (loss)	$258	$ 595	$ (560)
Basic and diluted earnings (loss) per share:			
Reported net income (loss)		$ 2.03	$(1.93)
Add: Goodwill amortization, net of tax		0.18	—
Less: Goodwill impairment relating to exiting communications business (1)		(0.07)	—
Adjusted basic and diluted earnings (loss) per share		$ 2.14	$(1.93)

(1) This impairment of $19 million, net of tax, is included in the annual goodwill amortization amount, net of tax, of $51 million.

The components of other intangible assets consist of the following:

	Weighted-Average Amortization Period (Years)	December 31, 2001 Carrying Amount	December 31, 2001 Accumulated Amortization	December 31, 2002 Carrying Amount	December 31, 2002 Accumulated Amortization
		(in millions)			
Air emission regulatory allowances	36	$255	$ (78)	$586	$(120)
Contractual rights	8	—	—	106	(26)
Power generation site permits	35	77	(3)	77	(6)
Water rights	35	68	(4)	68	(6)
FERC licenses	38	—	—	57	(1)
Other	5	—	—	5	(3)
Total		$400	$ (85)	$899	$(162)

We recognize specifically identifiable intangibles, including air emissions regulatory allowances, contractual rights, power generation site permits, water rights and FERC licenses, when specific rights and contracts are acquired. We have no intangible assets with indefinite lives recorded as of December 31, 2002. We amortize air emissions regulatory allowances primarily on a units-of-production basis as utilized. We amortize other acquired intangibles, excluding contractual rights, on a straight-line basis over the lesser of their contractual or estimated useful lives. All intangibles, excluding goodwill, are subject to amortization.

In connection with the acquisition of Orion Power, we recorded the fair value of certain fuel and power contracts acquired. We estimated the fair value of the contracts using forward pricing curves as of the acquisition date over the life of each contract. Those contracts with positive fair values at the date of acquisition (contractual rights) were recorded to intangible assets and those contracts with negative fair values at the date of acquisition (contractual obligations) were recorded to other current and long-term liabilities in the consolidated balance sheet.

Contractual rights and contractual obligations are amortized to fuel expense and revenues, as applicable, based on the estimated realization of the fair value established on the acquisition date over the contractual lives. There may be times during the life of the contract when accumulated amortization exceeds the carrying value of the recorded assets or liabilities due to the timing of realizing the fair value established on the acquisition date.

Estimated amortization expense, excluding contractual rights and obligations, for the next five years is as follows (in millions):

2003	$ 36
2004	28
2005	28
2006	27
2007	24
Total	$143

We amortized $26 million and $29 million of contractual rights and contractual obligations, respectively, for a net amount of $3 million, during 2002. Estimated amortization of contractual rights and contractual obligations for the next five years is as follows:

	Contractual Rights	Contractual Obligations	Net Decrease in Income
		(in millions)	
2003	$ 36	$(33)	$ 3
2004	35	(31)	4
2005	17	(9)	8
2006	13	(3)	10
2007	21	(1)	20
Total	$122	$(77)	$45

As of December 31, 2001 and 2002, we had $32 million and $135 million, respectively, of net goodwill recorded in our consolidated balance sheets that is deductible for United States income tax purposes for future periods.

The following tables show the composition of goodwill by reportable segment as of December 31, 2001 and 2002 and changes in the carrying amount of goodwill for 2001 and 2002, by reportable segment:

	As of January 1, 2001	Amortization Expense	Impairment	Foreign Currency Exchange Impact	Other	As of December 31, 2001
			(in millions)			
Retail energy	$ 34	$ (2)	$ —	$ —	$ —	$ 32
Wholesale energy	194	(4)	—	—	(6)	184
European energy	760	(26)	—	(60)	1	675
Other	19	—	(19)	—	—	—
Total	$1,007	$ (32)	$ (19)	$ (60)	$ (5)	$ 891

	As of January 1, 2002	Goodwill Acquired During the Period	Impairments	Foreign Currency Exchange Impact	Other	As of December 31, 2002
			(in millions)			
Retail energy	$ 32	$ —	$ —	$ —	$ —	$ 32
Wholesale energy	184	1,324	—	—	1	1,509
European energy	675	—	(716)	68	(27)	—
Total	$ 891	$1,324	$(716)	$ 68	$ (26)	$1,541

During the fourth quarter of 2002, we reached an agreement with the Dutch tax authorities on the tax basis of property, plant and equipment as of the date of our acquisition of REPGB and accordingly we recorded a $27 million reduction to deferred tax liability with the offset recorded to goodwill.

During the third quarter of 2002, we completed the transitional impairment test for the adoption of SFAS No. 142 on our consolidated financial statements, including the review of goodwill for impairment as of

January 1, 2002. This impairment test is performed in two steps. The initial step is designed to identify potential goodwill impairment by comparing an estimate of the fair value of the applicable reporting unit to its carrying value, including goodwill. If the carrying value exceeded fair value, a second step is performed, which compares the implied fair value of the applicable reporting unit's goodwill with the carrying amount of that goodwill, to measure the amount of the goodwill impairment, if any. Based on this impairment test, we recorded an impairment of our European energy segment's goodwill of $234 million, net of tax. This impairment loss was recorded retroactively as a cumulative effect of a change in accounting principle for the quarter ended March 31, 2002. Based on the first step of this goodwill impairment test, no goodwill was impaired for our other reporting units.

The circumstances leading to the goodwill impairment of our European energy segment included a significant decline in electric margins attributable to the deregulation of the European electricity market in 2001, lack of growth in the wholesale energy trading markets in Northwest Europe, continued regulation of certain European fuel markets and the reduction of proprietary trading in our European operations. Our measurement of the fair value of the European energy segment was based on a weighted-average approach considering both an income approach, using future discounted cash flows, and a market approach, using acquisition multiples, including price per MW, based on publicly available data for recently completed European transactions.

As of March 31, 2002, we completed our assessment of intangible assets and no indefinite lived intangible assets were identified. No related impairment losses were recorded in the first quarter of 2002 and no changes were made to the expected useful lives of our intangible assets as a result of this assessment.

SFAS No. 142 also requires goodwill to be tested annually and between annual tests if events occur or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We have elected to perform our annual test for indications of goodwill impairment as of November 1, in conjunction with our annual planning process. In estimating the fair value of our European energy segment for the annual impairment test, we considered the sales price in the agreement that we signed in February 2003 to sell our European energy operations to a Netherlands-based electricity distributor (see note 21(b)). We concluded that the sales price reflects the best estimate of fair value of our European energy segment as of November 1, 2002, to use in our annual impairment test. Based on our annual impairment test, we determined that an impairment of the full amount of our European energy segment's net goodwill of $482 million should be recorded in the fourth quarter of 2002. For additional information regarding this transaction and its impacts, see note 21(b).

Based on our annual impairment test, no goodwill was impaired for our other reporting units. Our impairment analyses for our other reporting units include numerous assumptions, including but not limited to:

- increases in demand for power that will result in the tightening of supply surpluses and additional capacity requirements over the next three to eight years, depending on the region;
- improving prices in electric energy, ancillary services and existing capacity markets as the power supply surplus is absorbed; and
- our expectation that more balanced, fair market rules will be implemented, which provide for the efficient operations of unregulated power markets, including capacity markets or mechanisms in regions where they currently do not exist.

These assumptions are consistent with our fundamental belief that long run market prices must reach levels sufficient to support an adequate rate of return on the construction of new power generation.

An impairment analysis requires estimates of future market prices, valuation of plant and equipment, growth, competition and many other factors as of the determination date. The resulting impairment analysis is highly dependent on these underlying assumptions. Such assumptions are consistent with those utilized in our annual planning process and industry valuation and appraisal reports. If the assumptions and estimates underlying this goodwill impairment evaluation differ greatly from the actual results or to the extent that such assumptions change through time, there could be additional goodwill impairments in the future.

(7) DERIVATIVE INSTRUMENTS, INCLUDING ENERGY TRADING, MARKETING, PRICE RISK MANAGEMENT SERVICES AND POWER ORIGINATION ACTIVITIES.

Effective January 1, 2001, we adopted SFAS No. 133, which establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. This statement requires that 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 accumulated other comprehensive income (loss), net of applicable taxes, depending on the intended use of the derivative, its resulting designation and its effectiveness. If certain conditions are met, an entity may designate a derivative instrument as hedging (a) the exposure to changes in the fair value of an asset or liability (fair value hedge), (b) the exposure to variability in expected future cash flows (cash flow hedge) or (c) the foreign currency exposure of a net investment in a foreign operation. For a derivative not designated as a hedging instrument, the gain or loss is recognized in earnings in the period it occurs. During 2001 and 2002, we did not enter into any fair value hedges.

Adoption of SFAS No. 133 on January 1, 2001 resulted in an after-tax increase in net income of $3 million and a cumulative after-tax increase in accumulated other comprehensive loss of $460 million. The adoption also increased current assets, long-term assets, current liabilities and long-term liabilities by $566 million, $127 million, $811 million and $339 million, respectively, in our consolidated balance sheet. During 2001, $249 million of the initial after-tax transition adjustment recorded in accumulated other comprehensive loss was recognized in net income.

We are exposed to various market risks. These risks arise from transactions entered into in the normal course of business and are inherent in our consolidated financial statements. We have utilized derivative instruments such as futures, physical forward contracts, swaps and options (energy derivatives) to mitigate the impact of changes in electricity, natural gas and fuel prices on our operating results and cash flows. We have utilized (a) cross-currency swaps, forward contracts and options to hedge our net investments in and cash flows of our foreign subsidiaries, (b) interest rate swaps to mitigate the impact of changes in interest rates and (c) other financial instruments to manage various other market risks.

Trading, marketing and hedging operations often involve risk associated with managing energy commodities and in certain circumstances establishing open positions in the energy markets, primarily on a short-term basis. These risks fall into three different categories: price and volume volatility, credit risk of trading counterparties and adequacy of the control environment for trading. We routinely enter into energy derivatives to hedge sale commitments, fuel requirements and inventories of natural gas, coal, electricity, crude oil and products and other commodities to minimize the risk of market fluctuations in our trading, marketing, power origination and risk management services operations.

The primary types of energy derivatives we use are described below:

- Futures contracts are exchange-traded standardized commitments to purchase or sell an energy commodity or financial instrument, or to make a cash settlement, at a specific price and future date.

- Physical forward contracts are commitments to purchase or sell energy commodities in the future.
- Swap agreements require payments to or from counterparties based upon the differential between a fixed price and variable index price (fixed price swap) or two variable index prices (variable price swap) for a predetermined contractual notional amount. The respective index may be an exchange quotation or an industry pricing publication.
- Option contracts convey the right to buy or sell an energy commodity or a financial instrument at a predetermined price or settlement of the differential between a fixed price and a variable index price or two variable index prices.

(a) Energy Trading, Marketing, Price Risk Management Services and Certain Power Origination Activities.

Trading and marketing activities include (a) transactions establishing open positions in the energy markets, primarily on a short-term basis, (b) transactions intended to optimize our power generation portfolio, but which do not qualify for hedge accounting and (c) energy price risk management services to customers primarily related to natural gas, electric power and other energy-related commodities. We provide these services by utilizing a variety of derivative instruments (trading energy derivatives).

See note 2(t), which discusses the EITF's rescission of EITF No. 98-10 by issuance of EITF No. 02-03. All new contracts entered into on or after October 25, 2002, can no longer be marked-to-market through earnings, unless the contract is within the scope of SFAS No. 133. Note 2(t) also discusses the estimated cumulative effect of a change in accounting principle to be recorded effective January 1, 2003.

We applied mark-to-market accounting for our energy trading, marketing, price risk management services to customers and certain origination activities in our operations in North America and Europe. We also applied mark-to-market accounting to contracted sales by our retail energy segment to large commercial, industrial and institutional customers and the related energy supply contracts for contracts entered into prior to October 25, 2002. Accordingly, these contracts are recorded at fair value with net realized and unrealized gains (losses) recorded as a component of revenues. The recognized, unrealized balances are recorded as trading and marketing assets/liabilities in the consolidated balance sheets. In addition, trading and marketing assets/liabilities include option premiums for trading activities. Contracted sales by our retail energy segment to large commercial, industrial and institutional customers and the related energy supply contracts entered into after October 25, 2002, will, for the most part, no longer be marked-to-market through earnings. For contracted sales by our retail energy segment to large commercial, industrial and institutional customers and the related energy supply contracts entered into after October 25, 2002 that are derivatives pursuant to SFAS No. 133, we will apply hedge accounting or designate them as "normal," as further described below.

The fair values as of December 31, 2001 and 2002, are estimated by using quoted prices where available and other valuation techniques when market data is not available, for example in illiquid markets. Our alternative pricing methodologies include, but are not limited to, extrapolation of forward pricing curves using historically reported data from illiquid pricing points. These same pricing techniques are used to evaluate a contract prior to taking a position.

Other factors affecting our estimates of fair values include valuation adjustments relating to time value, the volatility of the underlying commitment, the cost of administering future obligations under existing contracts, and the credit risk of counterparties. Volatility valuation adjustments are calculated by utilizing observed market price volatility and represent the estimated impact on fair values resulting from potential fluctuations in current prices. Credit adjustments are based on estimated defaults by counterparties and are calculated using historical default ratings for corporate bonds for companies with similar credit ratings.

The fair values are subject to significant changes based on fluctuating market prices and conditions. Changes in the assets and liabilities from trading, marketing, power origination and price risk management services result primarily from changes in the valuation of the portfolio of contracts, newly originated transactions and the timing of settlements. The most significant parameters impacting the value of our portfolio of contracts include natural gas and power forward market prices, volatility and credit risk. For the contracted retail electric sales to large commercial, industrial and institutional customers, significant variables affecting contract values also include the variability in electricity consumption patterns due to weather and operational uncertainties (within contract parameters). Insufficient market liquidity could significantly affect the values that could be obtained for these contracts, as well as the costs at which these contracts could be hedged.

The weighted-average term of the trading portfolio, based on fair values, is approximately one year. The maximum term of any contract in the trading portfolio is 15 years. These maximum and average terms are not indicative of likely future cash flows, as these positions may be changed by new transactions in the trading portfolio at any time in response to changing market conditions, market liquidity and our risk management portfolio needs and strategies. Terms regarding cash settlements of these contracts vary with respect to the actual timing of cash receipts and payments.

(b) Non-Trading Activities.

Cash Flow Hedges. To reduce the risk from market fluctuations in revenues and the resulting cash flows derived from the sale of electric power, we may enter into Energy Derivatives in order to hedge some expected purchases of electric power, natural gas and other commodities and sales of electric power (non-trading energy derivatives). The non-trading energy derivative portfolios are managed to complement the physical transaction portfolio, reducing overall risks within authorized limits.

We apply hedge accounting for our non-trading energy derivatives utilized in non-trading activities only if there is a high correlation between price movements in the derivative and the item designated as being hedged. This correlation, a measure of hedge effectiveness, is measured both at the inception of the hedge and on an ongoing basis, with an acceptable level of correlation of at least 80% to 125% for hedge designation. If and when correlation ceases to exist at an acceptable level, hedge accounting ceases and prospective changes in fair value are recognized currently in our results of operations. During 2001 and 2002, the amount of hedge ineffectiveness recognized in revenues from derivatives that are designated and qualify as cash flow hedges, including interest rate swaps, was a gain of $37 million and a loss of $8 million, respectively. For 2001 and 2002, no component of the derivative instruments' gain or loss was excluded from the assessment of effectiveness. If it becomes probable that an anticipated transaction will not occur, we realize in net income (loss) the deferred gains and losses recognized in accumulated other comprehensive loss. During 2001 and 2002, there were zero and $16 million, respectively, which is excluded from the hedge ineffectiveness above, of losses recognized in earnings as a result of the discontinuance of cash flow hedges because it was no longer probable that the forecasted transaction would occur. The losses reclassified into earnings in 2002 primarily related to deferred losses of interest rate swaps. Once the anticipated transaction occurs, the accumulated deferred gain or loss recognized in accumulated other comprehensive loss is reclassified and included in our statements of consolidated operations under the captions (a) fuel expenses, in the case of natural gas purchase transactions, (b) purchased power, in the case of electric power purchase transactions, (c) revenues, in the case of electric power and natural gas sales transactions and financial electric power or natural gas derivatives and (d) interest expense, in the case of interest rate swap transactions. As of December 31, 2002, we expect $12 million of accumulated other comprehensive loss to be reclassified into net income during the next twelve months.

As of December 31, 2001 and 2002, the maximum length of time we are hedging our exposure to the variability in future cash flows for forecasted transactions excluding the payment of variable interest on existing financial instruments is 11 years and 10 years, respectively. As of December 31, 2001 and 2002, the maximum length of time we are hedging our exposure to the payment of variable interest rates is four years and seven years, respectively.

For a discussion of our interest rate swaps, see note 9(d).

As of December 31, 2001 and 2002, our European energy segment has entered into forward and swap contracts to purchase $271 million and $143 million, respectively, at a fixed exchange rate in order to hedge future fuel purchases payable in U.S. dollars.

Hedge of the Foreign Currency Exposure of Net Investment in Foreign Subsidiaries. During the normal course of business, we review our currency hedging strategies and determine the hedging approach deemed appropriate based upon the circumstances of each situation. Until December 2002, we substantially hedged our entire net investment in our European subsidiaries against a material decline of the Euro through a combination of Euro-denominated borrowings, foreign currency swaps, options and forward contracts to reduce our exposure to changes in foreign currency rates. In December 2002, we reduced our hedged position by approximately $1.1 billion to $1.4 billion and are using a combination of Euro-denominated borrowings and foreign currency options to reduce our exposure to changes in foreign currency rates. In March 2003, we adjusted the hedge of our net investment in our European energy operations; see note 21(b).

We record the changes in the value of the foreign currency hedging instruments and Euro-denominated borrowings as foreign currency translation adjustments included as a component of accumulated other comprehensive loss. The effectiveness of the hedging instruments can be measured by the net change in foreign currency translation adjustments attributed to our net investment in our European subsidiaries. Euro-denominated borrowings and foreign currency swaps and forward contracts generally offset amounts recorded in stockholders' equity as adjustments resulting from translation of the hedged investment into U.S. dollars while foreign currency options partially offset such amounts. During 2001 and 2002, the derivative and non-derivative instruments designated as hedging the net investment in our European subsidiaries resulted in a gain of $31 million and a loss of $210 million, respectively, which are included in the balance of the cumulative translation adjustment.

Other Derivatives. In December 2000, the Dutch parliament adopted legislation allocating to the Dutch generation sector, including REPGB, financial responsibility for various stranded costs contracts and other liabilities. In particular, the legislation allocated to the Dutch generation sectors, including REPGB, financial responsibility to purchase electricity and gas under gas supply and electricity contracts. For additional information regarding these stranded cost contracts and the related accounting pursuant to SFAS No. 133, see note 14(j).

During 2001, we entered into two structured transactions, which were recorded in the consolidated balance sheet in non-trading derivative assets and liabilities involving a series of forward contracts to buy and sell an energy commodity in 2001 and to buy and sell an energy commodity in 2002. The change in fair value of these derivative assets and liabilities must be recorded in the statement of consolidated operations for each reporting period. As of December 31, 2001 we have recorded $118 million of net non-trading derivative assets related to these transactions. During 2001 and 2002, $117 million of net non-trading derivative assets and $121 million of net non-trading derivative assets, respectively, were settled related to these transactions; $1 million and $3 million, respectively, of pre-tax unrealized gains were recognized.

(c) Credit Risks.

In addition to the risk associated with price movements, credit risk is inherent in our risk management activities and hedging activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. We have broad credit policies and parameters. It is our policy that all transactions must be within approved counterparty or customer credit limits. We seek to enter into contracts that permit us to net receivables and payables with a given counterparty. We also enter into contracts that enable us to obtain collateral from a counterparty as well as to terminate contracts upon the occurrence of certain events of default. We periodically review the financial condition of our counterparties. If the counterparties to these arrangements failed to perform, we would exercise our legal rights to obtain contractual remedies related to such non-performance. We might be forced to acquire alternative hedging arrangements or be required to replace the underlying commitment at then-current market prices. In this event, we might incur additional losses to the extent of amounts, if any, already paid to the counterparties. For information regarding the provision related to energy sales in California, see note 14(i). For information regarding the net provision recorded in 2001 related to energy sales to Enron, see note 17.

The following table shows the combined composition of our trading and marketing assets and our non-trading derivative assets, after taking into consideration netting within each contract and any master netting contracts with counterparties, as of December 31, 2001 and 2002:

Trading and Marketing Assets and Non-Trading Derivative Assets	December 31, 2001 Investment Grade (1)(2)	December 31, 2001 Total	December 31, 2002 Investment Grade (1)(2)	December 31, 2002 Total
	(in millions)			
Energy marketers	$ 488	$ 571	$258	$ 417
Financial institutions	58	58	133	133
Gas and electric utilities	346	348	138	148
Oil and gas producers	95	118	12	106
Industrial	32	54	16	33
Others	81	127	29	44
Total	$1,100	1,276	$586	881
Collateral held (3)		(167)		(188)
Total exposure, net of collateral		1,109		693
Credit and other reserves		(114)		(68)
		$ 995		$ 625

(1) "Investment Grade" is primarily determined using publicly available credit ratings along with the consideration of credit support (such as parent company guarantees).

(2) For unrated counterparties, we perform credit analyses, considering contractual rights and restrictions to create an internal credit rating.

(3) Collateral consists of cash and standby letters of credit.

Trading and marketing assets and liabilities and non-trading derivative assets and liabilities are presented separately in our consolidated balance sheets. The trading and non-trading derivative asset and trading and non-trading derivative liability balances were offset separately for trading and non-trading activities although in certain cases contracts permit the offset of trading and non-trading derivative assets and liabilities with a given counterparty. For the purpose of disclosing credit risk, trading and non-trading derivative assets and liabilities with a given counterparty were offset if the counterparty has entered into a contract with us which permits netting.

As of December 31, 2001, no individual counterparty accounted for more than 10% of our total credit exposure, net of collateral. As of December 31, 2002, one counterparty with a credit rating below investment grade represented 12% of our total credit exposure, net of collateral.

(d) Trading and Non-trading—General Policy.

We have established a risk oversight committee. The risk oversight committee, which is comprised of corporate officers and includes a working group of corporate and business segment officers, oversees all of our trading, marketing and hedging activities and other activities involving market risks. These activities expose us to commodity price, credit, foreign currency and interest rate risks. The committee's duties are to approve our commodity risk policies, allocate risk capital within limits established by our board of directors, approve trading of new products and commodities, monitor risk positions and monitor compliance with our risk management policies and procedures and trading limits established by our board of directors.

Our policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

(8) EQUITY INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

We have a 50% interest in a 470 MW electric generation plant in Boulder City, Nevada. The plant became operational in May 2000. We have a 50% partnership interest in a 108 MW cogeneration plant in Orange, Texas. In addition, we, through REPGB, have a 22.5% interest in NEA.

Currently, NEA does not have on-going operations and is in the process of resolving its existing contingencies and liquidating its remaining assets. Prior to 2001, NEA acted as the national electricity pooling and coordinating body for the generation output of REPGB and the three other large-scale national Dutch generation companies. During 2001, NEA sold its national grid transmission company, TenneT, to the Dutch government. As of December 31, 2001 and 2002, NEA's assets primarily consisted of proceeds held by NEA related to the sale of TenneT. Prior to 2001, NEA's operating results were derived from operating as the national electricity pooling and coordinating body for the generation output of the large-scale Dutch generation companies. Beginning in 2001, NEA no longer served in this capacity. During 2001 and 2002, NEA's income was derived from interest income from proceeds held by NEA related to the sale of TenneT and in addition, in 2001 from the gain on the sale of TenneT. In connection with the sale of our European energy operations (see note 21(b)), our investment in NEA will be sold. For additional information regarding our investment in NEA and financial impacts, see note 14(j).

Our equity investments in unconsolidated subsidiaries are as follows:

	As of December 31, 2001	As of December 31, 2002
	(in millions)	
Nevada generation plant	$ 57	$ 73
Texas cogeneration plant	31	30
NEA	299	210
Equity investments in unconsolidated subsidiaries	$387	$313

Our income from equity investments of unconsolidated subsidiaries is as follow:

	Year Ended December 31,		
	2000	2001	2002
	(in millions)		
Nevada generation plant	$ 42	$ 5	$16
Texas cogeneration plant	1	1	2
NEA	—	51	5
Income from equity investments in unconsolidated subsidiaries	$ 43	$57	$23

During 2000, 2001 and 2002, the net distributions were $18 million, $27 million and $140 million, respectively, from these investments. The 2002 net distributions include a $137 million distribution from NEA.

As of December 31, 2002, the companies, in which we have an unconsolidated equity investment, carry debt that is currently estimated to be $326 million ($113 million based on our proportionate ownership interests of the investments).

Summarized financial information for our equity method investments' operating results is as follows:

	Year Ended December 31,		
	2000	2001	2002
	(in millions)		
Nevada Generation Plant:			
Revenues	$ 260	$133	$101
Gross profit	127	22	19
Operating income (loss)	114	(5)	(5)
Net income (loss)	108	(12)	31
Texas Cogeneration Plant:			
Revenues	$ 39	$ 45	$ 41
Gross profit	11	11	12
Operating income	3	3	4
Net income	3	3	4
NEA:			
Revenues	$2,776	$—	$—
Gross profit	54	—	—
Operating income (loss)	245	81	(8)
Net income	292	774	20

Summarized financial information for our equity method investments' financial position is as follows:

	As of December 31, 2001	As of December 31, 2002
	(in millions)	
Nevada Generation Plant:		
Current assets	$ 22	$ 53
Noncurrent assets	247	243
Total	$ 269	$ 296
Current liabilities	$ 12	$ 14
Noncurrent liabilities	145	142
Equity	112	140
Total	$ 269	$ 296
Texas Cogeneration Plant:		
Current assets	$ 6	$ 11
Noncurrent assets	63	60
Total	$ 69	$ 71
Current liabilities	$ 6	$ 10
Noncurrent liabilities	—	—
Equity	63	61
Total	$ 69	$ 71
NEA:		
Current assets	$1,590	$1,201
Noncurrent assets	18	23
Total	$1,608	$1,224
Current liabilities	$ 611	$ 49
Noncurrent liabilities	195	188
Equity	802	987
Total	$1,608	$1,224

(9) BANKING OR DEBT FACILITIES, OTHER SHORT-TERM DEBT AND OTHER LONG-TERM DEBT

As more fully described in note 21(a), we refinanced certain credit facilities in March 2003.

The following table presents the components of our banking or debt facilities, other short-term debt and other long-term debt to third parties as of December 31, 2001 and 2002:

	2001			2002		
	Weighted Average Interest Rate(1)	Long-term	Current(2)	Weighted Average Interest Rate(1)	Long-term	Current(2)
	(in millions, excluding interest rates)					
Banking or Debt Facilities						
Other Operations Segment:						
Orion acquisition term loan	—	$—	$—	3.68%	$2,908	$ — (3)
364-day revolver/term loan	—	—	—	3.20	800	— (3)
Three-year revolver	—	—	—	3.13	208	350(3)
Wholesale Energy Segment:						
Orion Power and Subsidiaries:						
Orion MidWest and Orion NY term loans	—	—	—	3.96	1,211	109
Orion MidWest working capital facility	—	—	—	3.92	—	51
Orion NY working capital facility	—	—	—	—	—	—
Liberty Generating Project:						
Floating rate debt	—	—	—	3.02	—	103
Fixed rate debt	—	—	—	9.02	—	165
Reliant Energy Channelview LP:					—	
Equity bridge loan	2.63%	—	92	—	—	—
Term loan and working capital facility:						
Floating rate debt	3.56	235	2	2.81	290	8
Fixed rate debt	9.547	60	—	9.547	75	—
REMA letter of credit facilities	—	—	—	—	—	—
European Energy Segment:						
Reliant Energy Capital (Europe), Inc.(4)	4.64	534	—	4.19	—	630(5)
REPGB 364-day revolver(4)	4.18	—	155	—	—	—
REPGB letter of credit facility	—	—	—	—	—	—
Total facilities		829	249		5,492	1,416
Other Short-term Debt						
European Energy Segment:						
Short-term arrangements via brokers and financial institutions	3.51	—	50	—	—	—
Total other short-term debt		—	50		—	—
Other Long-term Debt						
Wholesale Energy Segment:						
Orion Power senior notes	—	—	—	12.0	400	—
Adjustment to fair value of debt(6)	—	—	—	—	66	8
Other	—	—	—	6.2	1	—
Retail Energy Segment:						
Other	—	—	—	5.41	3	6
European Energy Segment:						
REPGB debentures(4)(7)	7.35	38	22	6.65	37	1
Adjustment to fair value of debt(7)	—	1	—	—	—	—
Other						
Adjustment to fair value of interest rate swaps(6)	—	—	—	—	46	19
Total other long-term debt		39	22		553	34
Total debt		$868	$321		$6,045	$1,450

(1) The weighted average interest rate is for borrowings outstanding as of December 31, 2001 or 2002, as applicable.

(2) Includes amounts due within one year of the date noted, as well as loans outstanding under revolving and working capital facilities classified as current liabilities.

(3) See note 21(a) for a discussion of the facilities refinanced in March 2003. As a result of the refinancing, \$3.9 billion has been classified as long-term.

(4) Borrowings were primarily denominated in Euros and the assumed exchange rate was 0.8895 U.S. dollar per Euro and 1.0492 U.S. dollar per Euro at December 31, 2001 and 2002, respectively. The results of our European energy segment are consolidated on a one-month lag basis.

(5) In March 2003, we extended the maturity of this facility. See notes 21(b) and 21(c).

(6) Debt and interest rate swaps acquired in the Orion Power acquisition are adjusted to fair market value as of the acquisition date. Included in interest expense is amortization of \$5 million and \$25 million for valuation adjustments for debt and interest rate swaps, respectively, for 2002. These valuation adjustments are being amortized over the respective remaining terms of the related financial instruments.

(7) REPGB debt was adjusted to fair market value as of the acquisition date. The fair value adjustments are being amortized over the respective remaining term of the related long-term debt.

As of December 31, 2002, maturities of all facilities, other short-term debt and other long-term debt were \$1.4 billion in 2003, \$170 million in 2004, \$1.1 billion in 2005, \$515 million in 2006, \$3.4 billion in 2007 and \$720 million in 2008 and beyond.

(a) Banking or Debt Facilities.

The following table provides a summary of the amounts owed and amounts available as of December 31, 2002 under our various committed credit facilities:

	Total Committed Credit	Drawn Amount	Letters of Credit	Unused Amount	Commitments Expiring By December 31, 2003	Expiration Date
			(in millions)			
Other Operations Segment:						
Orion acquisition term loan	$2,908	$2,908	$—	$—	$2,908(1)	February 2003
364-day revolver/term loan	800	800	—	—	800(1)	August 2003
Three-year revolver	800	558	235	7	—(1)	August 2004
Wholesale Energy Segment:						
Orion Power and Subsidiaries:						
Orion MidWest and Orion NY term loans	1,320	1,320	—	—	109	March 2003-October 2005
Orion MidWest working capital facility	75	51	14	10	—	October 2005
Orion NY working capital facility	30	—	—	30	—	October 2005
Liberty Generating Project	290	268	17	5	8	January 2003-April 2026
Reliant Energy Channelview LP:						
Term loan and working capital facility	382	373	—	9	3	January 2003-July 2024
REMA letter of credit facilities	51	—	38	13	51	August 2003
European Energy Segment:						
Reliant Energy Capital (Europe), Inc.	630	630	—	—	630(2)(3)	March 2003
REPGB 364-day revolver	194	—	18(4)	176	194(2)	July 2003
REPGB letter of credit facility	420	—	355	65	420(2)	July 2003
Total	$7,900	$6,908	$677	$315	$5,123	

(1) In March 2003, these facilities were refinanced to mature in March 2007. See note 21(a) for further discussion.
(2) The results of our European energy segment are consolidated on a one-month lag basis.
(3) In March 2003, we extended the maturity of this facility. See notes 21(b) and 21(c).
(4) This amount excludes $12 million of cash collateralized letters of credit as they do not affect our availability under the facility.

As of December 31, 2002, we had $7.9 billion in committed credit facilities of which $315 million was unused. These facilities expired as follows (in millions):

2003	$5,123
2004	940
2005	1,210
2006	24
2007	61
2008 and beyond	542

As of December 31, 2002, committed credit facilities aggregating $5.2 billion were unsecured and $5.1 billion were scheduled to expire by December 31, 2003. As part of the refinancing in March 2003, the debt related to our construction agency agreements (see note 14(b)) together with the Orion acquisition term loan and the 364-day revolver/term loan and the three-year revolver were combined into a single credit facility which is now secured.

As of December 31, 2002, letters of credit outstanding under these facilities aggregated $677 million and borrowings aggregated $6.9 billion of which $5.5 billion were classified as long-term debt, based upon the refinancing as described in note 21(a) or the availability of committed credit facilities coupled with management's intention to maintain these borrowings in excess of one year.

As of December 31, 2001, we had $5.6 billion in committed credit facilities of which $4.1 billion remained unused. Credit facilities aggregating $4.6 billion were unsecured. As of December 31, 2001, letters of credit outstanding under these facilities aggregated $396 million. As of December 31, 2001, borrowings of $1.1 billion were outstanding under these facilities of which $829 million were classified as long-term debt, based upon the availability of committed credit facilities and management's intention to maintain these borrowings in excess of one year.

Orion Acquisition Term Loan. Reliant Resources entered into an unsecured $2.2 billion term loan facility during the fourth quarter of 2001, which was amended in January 2002 to provide for $2.9 billion in funding to finance the purchase of Orion Power. For discussion of the acquisition of Orion Power, see note 5(a). Interest rates on the borrowings under this facility are based on either (a) the London inter-bank offered rate (LIBOR) plus a margin based on Reliant Resources' credit rating and length of time outstanding, which was 2.0% at December 31, 2002 or (b) a base rate. This facility was funded on February 19, 2002 for $2.9 billion. The credit agreement contained affirmative and negative covenants, including a negative pledge, and a requirement to maintain a ratio of net debt to the sum of net debt, stockholders' equity and subordinated affiliate debt not to exceed 0.60 to 1.00. The maturity of this term loan was one year from the date on which it was funded. The maturity date was extended from February 19, 2003 to March 31, 2003. During March 2003, we refinanced this term loan facility (see note 21(a)).

364-day Revolver/Term Loan and Three-year Revolver. In 2001, Reliant Resources entered into two unsecured syndicated revolving credit facilities with a group of financial institutions, which provided for $800 million each or an aggregate of $1.6 billion in committed credit. The one-year term-out provision in the $800 million unsecured 364-day revolving credit facility was exercised before it matured on August 22, 2002, resulting in a one-year term loan with a maturity of August 22, 2003. The three-year revolver had a maturity date of August 22, 2004. As of December 31, 2001 and 2002, there were $0 and $1.4 billion in borrowings outstanding, respectively, under these facilities. At December 31, 2001 and 2002, letters of credit outstanding under these two facilities aggregated $51 million and $235 million, respectively. Interest rates on the borrowings were based on (a) LIBOR plus a margin based on our credit rating, (b) a base rate or (c) a rate determined through a bidding process. The LIBOR margin as of December 31, 2002 was 1.375% for the 364-day facility and 1.075% for the three-year facility. The credit agreements contained affirmative and negative covenants, including a negative pledge, that had to be met to borrow funds or obtain letters of credit and which required us to maintain a ratio of net debt to the sum of net debt, stockholders' equity and subordinated affiliate debt not to exceed 0.60 to 1.00. The revolving credit facilities were subject to facility and usage fees that were calculated based on the amount of the facility commitments and on the amounts outstanding under the facilities relative to the commitments, respectively. As of the term-out, the 364-day facility was subject to a facility fee that was based on the amount outstanding under the facility. During March 2003, we refinanced these facilities (see note 21(a)).

Orion Power's Debt Obligations. As a result of our acquisition of Orion Power in early 2002, our consolidated net debt obligations also increased by the amount of Orion Power's net debt obligations, which are discussed below. In October 2002, a portion of this debt was refinanced, the terms of which are also discussed below.

Orion Power Revolving Senior Credit Facility. Orion Power had an unsecured revolving senior credit facility. This facility was prepaid and terminated in October 2002 in connection with the execution of the amended and restated Orion MidWest and Orion NY credit facilities. See below for further discussion of the debt refinancing. The amount of this facility was reduced on September 6, 2002, from $75 million to $62 million in conjunction with a reduction of the total letters of credit outstanding. Amounts outstanding under the facility bore interest at a floating rate.

Orion MidWest Credit Agreement. Orion MidWest, an indirect wholly-owned subsidiary of Orion Power, had a secured credit agreement, which included a $988 million acquisition facility and a $75 million revolving working capital facility, including letters of credit. This debt was refinanced in October 2002; see below for further discussion. The loans bore interest at the borrower's option at LIBOR plus 2.00% or a base rate plus 1.00%.

Orion New York Credit Agreement. Orion NY, an indirect wholly-owned subsidiary of Orion Power, had a secured credit agreement, which included a $412 million acquisition facility and a $30 million revolving working capital facility, including letters of credit. This debt was refinanced in October 2002; see below for further discussion. The loans bore interest at the borrower's option at LIBOR plus 1.75% or a base rate plus 0.75%.

In connection with the Orion Power acquisition, the existing interest rate swaps for the Orion MidWest credit facility and the Orion NY credit facility were bifurcated into a debt component and a derivative component. The fair values of the debt components, approximately $59 million for the Orion MidWest credit facility and $31 million for the Orion NY credit facility, were based on our incremental borrowing rates at the acquisition date for similar types of borrowing arrangements. The value of the debt component will be reduced as interest rate swap payments are made. For the period from February 20, 2002 through December 31, 2002, the value of the debt component was reduced by $17 million and $8 million for Orion MidWest and Orion NY, respectively. See note 7 for information regarding our derivative financial instruments. See note 9(d) for further discussion regarding our interest-rate swaps.

Orion Power's Refinanced Debt. During October 2002, the Orion Power revolving credit facility was prepaid and terminated and, as part of the same transaction, we refinanced the Orion MidWest and Orion NY credit facilities, which refinancing included an extension of the maturities by three years to October 2005. In connection with these refinancings, we applied excess cash of $145 million to prepay and terminate the Orion Power revolving credit facility and to reduce the term loans and revolving working capital facilities at Orion MidWest and Orion NY. As of the refinancing date, the amended and restated Orion MidWest credit facility includes a term loan of approximately $974 million and a $75 million revolving working capital facility. As of the refinancing date, the amended and restated Orion NY credit facility includes a term loan of approximately $353 million and a $30 million revolving working capital facility. The loans under each facility bear interest at LIBOR plus a margin or at a base rate plus a margin. The LIBOR margin is 2.50% during the first twelve months, 2.75% during the next six months, 3.25% for the next six months and 3.75% thereafter. The base rate margin is 1.50% during the first twelve months, 1.75% for the next six months, 2.25% for the next six months and 2.75% thereafter. The amended and restated Orion NY credit facility is secured by a first lien on a substantial portion of the assets of Orion NY and its subsidiaries (excluding certain plants) and a second lien on substantially

all of the assets of Orion MidWest and its subsidiary. The amended and restated Orion MidWest credit facility is, in turn, secured by a first lien on substantially all of the assets of Orion MidWest and its subsidiary and a second lien on a substantial portion of the assets of Orion NY and its subsidiaries (excluding certain plants). Both the Orion MidWest and Orion NY credit facilities contain affirmative and negative covenants, including negative pledges, that must be met by each borrower under its respective facility to borrow funds or obtain letters of credit, and which require Orion MidWest and Orion NY to maintain a combined debt service coverage ratio of 1.5 to 1.0. These covenants are not anticipated to materially restrict either borrower's ability to borrow funds or obtain letters of credit under its respective credit facility. The facilities also provide for any available cash under one facility to be made available to the other borrower to meet shortfalls in the other borrower's ability to make certain payments, including operating costs. This is effected through distributions of such available cash to Orion Power Capital, LLC, a direct subsidiary of Orion Power formed in connection with the refinancing. Orion Power Capital, LLC, as indirect owner of each of Orion MidWest and Orion NY, can then contribute such cash to the other borrower. Although cash sufficient to make the November and December 2002 payments on Orion Power's 12% senior notes and 4.5% convertible senior notes (each described below) was provided in connection with the refinancing, the ability of the borrowers to make subsequent dividends to Orion Power for such interest payments or otherwise is subject to certain requirements (described below) that are likely to restrict such dividends.

As of December 31, 2002, Orion MidWest had $969 million and $51 million of term loans and revolving working capital facility loans outstanding, respectively. A total of $14 million in letters of credit were also outstanding under the Orion MidWest credit facility. As of December 31, 2002, Orion NY had $351 million of term loans outstanding. There were no loans or letters of credit outstanding under the Orion NY working capital facility. As of December 31, 2002, restricted cash under the Orion MidWest and the Orion NY credit facilities was $72 million and $73 million, respectively, and $27 million at Orion Capital. Such restricted cash may be dividended to Orion Power if Orion MidWest and Orion NY have made certain prepayments and a number of distribution tests have been met, including satisfaction of certain debt service coverage ratios and the absence of events of default. It is likely that these tests will restrict a dividend of such restricted cash to Orion Power. Any restricted cash which is not dividended will be applied on a quarterly basis to prepay on a pro rata basis outstanding loans at Orion MidWest and Orion NY. No distributions may be made under any circumstances after October 28, 2004. Orion MidWest's and Orion NY's obligations under the respective facilities are non-recourse to Reliant Resources.

Liberty Credit Agreement. In July 2000, Liberty Electric Power, LLC (LEP) and Liberty Electric PA, LLC (Liberty), indirect wholly-owned subsidiaries of Orion Power, entered into a facility that provides for (a) a construction/term loan in an amount of up to $105 million; (b) an institutional term loan in an amount of up to $165 million; (c) a revolving working capital facility for an amount of up to $5 million; and (d) a debt service reserve letter of credit facility of $17 million. The outstanding borrowings related to the Liberty credit agreement are non-recourse to Reliant Resources.

In May 2002, the construction loans were converted to term loans. As of the conversion date, the term loans had an outstanding principal balance of $270 million, with $105 million having a final maturity in 2012 and the balance having maturities through 2026. On the conversion date, Orion Power made the required cash equity contribution of $30 million into Liberty, which was used to repay a like amount of equity bridge loans advanced by the lenders. A related $41 million letter of credit furnished by Orion Power as credit support was returned for cancellation. In addition, on the conversion date, a $17 million letter of credit was issued in satisfaction of Liberty's obligation to provide a debt service reserve. The facility also provides for a $5 million working capital line of credit. The debt service reserve letter of credit facility and the working capital facility expire in May 2007.

As of December 31, 2002, amounts outstanding under the Liberty credit agreement bear interest at a floating rate, which may be either LIBOR plus 1.25% or a base rate plus 0.25%, except for the institutional term loan which bears interest at a fixed rate of 9.02%. For the floating rate term loan, the LIBOR margin is 1.25% during the first 36 months from the conversion date, 1.375% during the next 36 months and 1.625% thereafter. The base rate margin is 0.25% during the first 36 months from the conversion date, 0.375% during the next 36 months and 0.625% thereafter. The LIBOR margin for the revolving working capital facility is 1.25% during the first 36 months from the conversion date and 1.375% thereafter. The base rate margin is 0.25% during the first 36 months from the conversion date and 0.375% thereafter. As of December 31, 2002, Liberty had $103 million and $165 million of the floating rate and fixed rate portions of the facility outstanding, respectively. A $17 million letter of credit was also outstanding under the Liberty credit agreement.

The lenders under the Liberty credit agreement have a security interest in substantially all of the assets of Liberty. The Liberty credit agreement contains affirmative and negative covenants, including a negative pledge, that must be met to borrow funds or obtain letters of credit. Liberty is currently unable to access the working capital facility (see note 14(l)). Additionally, the Liberty credit agreement restricts Liberty's ability to, among other things, make dividend distributions unless Liberty satisfies various conditions. As of December 31, 2002, restricted cash under the Liberty credit agreement totaled $27 million.

For additional information regarding the Liberty credit agreement related issues and concerns, see note 14(l). Given that we believe that it is probable that a default will occur and thus make the obligation callable before December 31, 2003, we have classified the debt as a current liability.

Reliant Energy Channelview L.P. In 1999, a special purpose project subsidiary of Reliant Energy Power Generation, Inc. (REPG), Reliant Energy Channelview L.P., entered into a $475 million syndicated credit facility to finance the construction and start-up operations of an electric power generation plant located in Channelview, Texas. The maximum availability under this facility was (a) $92 million in equity bridge loans for the purpose of paying or reimbursing project costs, (b) $369 million in loans to finance the construction of the project and (c) $14 million in revolving loans for general working capital purposes.

As of December 31, 2001, the project subsidiary had drawn $389 million in equity bridge and construction loans. In November 2002, the construction loans were converted to term loans. On the conversion date, subsidiaries of REPG contributed cash equity and subordinated debt of $92 million into Channelview, which was used to repay a like amount of equity bridge loans advanced by the lenders. As of December 31, 2002, Channelview had $368 million and $5 million of term loans and revolving working capital facility loans outstanding, respectively. The outstanding borrowings related to the Channelview credit agreement are non-recourse to Reliant Resources. The term loans have final maturities ranging from 2017 to 2024. The revolving working capital facility matures in 2007.

As of December 31, 2002, with the exception of two tranches which total $91 million, the term loans and revolving working capital facility loans bear a floating rate interest at the borrower's option of either (a) a base rate of prime plus a margin of 0.25% or (b) LIBOR plus a margin of 1.25%. For $252 million of the term loans and the working capital facility loans, the LIBOR margin is 1.25% during the first 60 months from the conversion date, 1.45% during the next 48 months, 1.75% during the following 48 months and 2.125% thereafter. The base rate margin is 0.25% during the first 60 months from the conversion date, 0.45% during the next 48 months, 0.75% during the following 48 months and 1.125% thereafter. For $30 million of the term loans, the LIBOR margin is 1.25% during the first 60 months from the conversion date, 1.45% during the next 48 months, 1.875% during the following 48 months and 2.25% thereafter. The base rate margin is 0.25% during the first 60

months from the conversion date, 0.45% during the next 48 months, 0.875% during the following 48 months and 1.25% thereafter. One tranche of $16 million bears a floating rate interest at the borrower's option of either (a) a base rate plus a margin of 2.407% or (b) LIBOR plus a margin of 3.407% throughout its term. A second tranche of $75 million bears interest at a fixed rate of 9.547% throughout its term.

Obligations under the term loans and revolving working capital facility are secured by substantially all of the assets of the borrower. The Channelview credit agreement contains affirmative and negative covenants, including a negative pledge, that must be met to borrow funds. These covenants are not anticipated to materially restrict Channelview's ability to borrow funds under the credit facility. Additionally, the Channelview credit agreement allows Channelview to pay dividends or make restricted payments only if specified conditions are satisfied, including maintaining specified debt service coverage ratios and debt service reserve account balances. As of December 31, 2002, restricted cash under the credit agreement totaled $13 million.

REMA Letter of Credit Facilities. REMA's lease obligations are currently supported by three letters of credit issued under three separate unsecured letter of credit facilities. See note 14(a) for a discussion of REMA's lease obligations. The letter of credit facilities expire in August 2003. The amount of each letter of credit is equal to an amount representing the greater of (a) the next six months' scheduled rental payments under the related lease, or (b) 50% of the scheduled rental payments due in the next twelve months under the related lease. Under the letter of credit facilities, REMA pays a fee based on its assigned credit rating. As of December 31, 2002, the fee equaled 2.75% of the total amount of the outstanding letters of credit. As of December 31, 2001 and 2002, there were $73 and $38 million, respectively, in letters of credit outstanding under the facilities. While borrowings under the letter of credit facilities are non-recourse to Reliant Resources, the guarantee issued by REMA's subsidiaries relating to the lease obligations also covers REMA's obligations under these facilities. REMA anticipates refinancing or replacing the letter of credit facilities prior to their maturity. REMA anticipates that the terms may be more restrictive and may include higher fees.

Reliant Energy Capital (Europe), Inc. In February 2000, one of our subsidiaries, Reliant Energy Capital (Europe), Inc., established a Euro 600 million term loan facility ($630 million assuming the December 31, 2002 exchange rate of 1.0492 U.S. dollar per Euro) that was to terminate in March 2003. The facility bears interest at the inter-bank offered rate for Euros (EURIBOR) plus 1.25%. At December 31, 2001 and 2002, $534 million and $630 million, respectively, under this facility was outstanding. This facility is secured by a pledge of the shares of REPGB's indirect holding company. Borrowings under this facility are non-recourse to Reliant Resources. This facility contains affirmative and negative covenants, including a negative pledge, and a requirement for Reliant Energy Capital (Europe), Inc. to, among other things, maintain a ratio of net balance sheet debt to the sum of net balance sheet debt and total equity of 0.60 to 1.00. In March 2003, we extended the maturity of this facility (see notes 21(b) and 21(c)).

REPGB 364-day Revolver and REPGB Letter of Credit Facility. In July 2000, REPGB entered into two unsecured credit facilities, which included (a) a 364-day revolving credit facility for Euro 250 million, which was initially extended one year in July 2001 and (b) a three-year letter of credit facility for $420 million. These credit facilities will be used by REPGB for working capital purposes and to support REPGB's contingent obligations under its cross border leases (see note 14(d)). Under the two facilities, there is no recourse to Reliant Resources.

During July 2002, REPGB renewed its 364-day revolving credit facility for another year. The term of this facility is now scheduled to expire in July 2003. The amount of the revolving credit facility was reduced from Euro 250 million (approximately $262 million) to Euro 184 million (approximately $194 million). An option was added that permits REPGB to utilize up to Euro 100 million (approximately $105 million) of the facility for

letters of credit. The 364-day revolving credit facility bears interest at EURIBOR plus a margin depending on REPGB's credit rating. The EURIBOR margin as of December 31, 2002 was 2.00%. At December 31, 2001 and 2002, borrowings of $155 million and $0, respectively, were outstanding under this facility. At December 31, 2001 and 2002, there were $0 and $18 million, respectively, of letters of credit outstanding under the 364-day revolving credit facility. At December 31, 2001 and 2002, under the $420 million letter of credit facility, letters of credit of $272 million and $355 million, respectively, were outstanding under the facility. These facilities contain affirmative and negative covenants, including a negative pledge, that must be met by REPGB to borrow funds or obtain letters of credit and that require REPGB to, among other things, maintain a ratio of net balance sheet debt to the sum of net balance sheet debt and total equity of 0.60 to 1.00. These covenants are not anticipated to materially restrict REPGB from borrowing funds or obtaining letters of credit, as applicable, under these facilities. If the sale of our European energy operations (see note 21(b)) does not close prior to the maturity of these facilities, REPGB anticipates extending these credit facilities.

(b) Other Short-term Debt.

As of December 31, 2001, we, through REPGB, had $50 million of short-term borrowings arranged via brokers or directly from financial institutions. These borrowings were used by REPGB to meet its short-term liquidity needs.

(c) Other Long-term Debt.

Orion Convertible Senior Notes. As of the acquisition date, Orion Power had outstanding $200 million of aggregate principal amount of 4.5% convertible senior notes, due on June 1, 2008. Pursuant to certain change of control provisions, Orion Power commenced an offer to repurchase the convertible senior notes on March 1, 2002, which expired on April 10, 2002. During the second quarter of 2002, we repurchased $189 million in principal amount under the offer to repurchase. During the fourth quarter of 2002, the remaining $11 million aggregate principal amount of the convertible senior notes were repurchased for $8 million.

Orion Power Senior Notes. Orion Power has outstanding $400 million aggregate principal amount of 12% senior notes due 2010. The senior notes are senior unsecured obligations of Orion Power. Orion Power is not required to make any mandatory redemption or sinking fund payments with respect to the senior notes. The senior notes are not guaranteed by any of Orion Power's subsidiaries and are non-recourse to Reliant Resources. In connection with the Orion Power acquisition, we recorded the senior notes at an estimated fair value of $479 million. The $79 million premium is amortized against interest expense over the life of the senior notes. For the period February 20, 2002 to December 31, 2002, $5 million was amortized to interest expense for the senior notes. The fair value of the senior notes was based on our incremental borrowing rates for similar types of borrowing arrangements as of the acquisition date. The senior notes indenture contains covenants that include, among others, restrictions on the payment of dividends by Orion Power.

Pursuant to certain change of control provisions, Orion Power commenced an offer to repurchase the senior notes on March 21, 2002. The offer to repurchase expired on April 18, 2002. There were no acceptances of the offer to repurchase and the entire $400 million aggregate principal amount remains outstanding. Before May 1, 2003, Orion Power may redeem up to 35% of the senior notes issued under the indenture at a redemption price of 112% of the principal amount of the notes redeemed, plus accrued and unpaid interest and special interest, with the net cash proceeds of an equity offering provided that certain provisions under the indenture are met.

European Energy. Outstanding long-term indebtedness of REPGB of $61 million and $38 million at December 31, 2001 and 2002, respectively, consisted primarily of medium term notes and loans maturing

through 2006. This debt is unsecured and non-recourse to Reliant Resources. Some covenants under these loans restrict some actions by REPGB. During the second quarter of 2000, REPGB negotiated the repurchase of $272 million aggregate principal amount of its long-term debt for a total cost of $286 million, including $14 million in expenses. The book value of the debt repurchased was $293 million, resulting in an extraordinary gain on the early extinguishment of long-term debt of $7 million. Borrowings under a short-term banking facility and proceeds from the sale of trading securities by REPGB were used to finance the debt repurchase.

(d) Interest-rate Swaps.

Certain of our subsidiaries are party to interest rate swap contracts with an aggregate notional amount of $200 million and $1.1 billion as of December 31, 2001 and 2002, respectively, that fix the interest rate applicable to floating rate long-term debt. As of December 31, 2002, floating rate LIBOR-based interest payments are exchanged for weighted fixed rate interest payments of 6.97%. These swaps qualify for hedge accounting as cash flow hedges under SFAS No. 133 and the periodic settlements are recognized as an adjustment to interest expense in the statements of consolidated operations over the term of the swap agreements. See note 7 for further discussion of our cash flow hedges.

In January 2002, we entered into forward-starting interest rate swaps having an aggregate notional amount of $1.0 billion to hedge the interest rate on a portion of future offerings of long-term fixed-rate notes. On May 9, 2002, we liquidated $500 million of these forward-starting interest rate swaps. The liquidation of these swaps resulted in a loss of $3 million, which was recorded in accumulated other comprehensive loss and will be amortized into interest expense in the same period during which the forecasted interest payment affects earnings. In November 2002, we liquidated the remaining $500 million of swaps at a loss of $52 million that was recorded in accumulated other comprehensive loss and will be amortized into interest expense in the same period during which the forecasted interest payment affects earnings. For 2002, we recognized $16 million as interest expense relating to the reclassification of the deferred components in accumulated other comprehensive loss for forecasted interest payments that were probable of not occurring. Should other forecasted interest payments become probable of not occurring, any applicable deferred amounts will be recognized immediately as an expense. At December 31, 2002, the unamortized balance of such loss was $39 million.

(10) STOCKHOLDERS' EQUITY

(a) Initial Public Offering.

In May 2001, Reliant Resources offered 59.8 million shares of its common stock to the public at an IPO price of $30 per share and received net proceeds from the IPO of $1.7 billion. Pursuant to the terms of the Master Separation Agreement, we used $147 million of the net proceeds to repay certain indebtedness owed to CenterPoint. We used the remainder of the net proceeds of our IPO for repayment of third party borrowings, capital expenditures, repurchases of our common stock and payment of taxes, interest and other payables.

(b) Treasury Stock Purchases.

In July 2001, our board of directors authorized us to purchase up to one million shares of our common stock in anticipation of funding benefit plan obligations expected to be funded prior to the Distribution. On September 18, 2001, our board of directors authorized us to purchase up to 10 million additional shares of our common stock through February 2003. During 2001, we purchased 11 million shares of our common stock at an average price of $17.22 per share, or an aggregate purchase price of $189 million. The 11 million shares in

treasury stock purchases increased CenterPoint's percentage ownership in us from approximately 80% to approximately 83%. CenterPoint recorded the acquisition of treasury shares under the purchase method of accounting and pushed down the effect to us. As such, we recorded a decrease in property, plant and equipment of $67 million and an increase in accumulated deferred income tax assets of $24 million related to REPGB and a decrease in additional paid-in capital of $43 million.

On December 6, 2001, our board of directors authorized us to purchase up to an additional 10 million shares of our common stock through June 2003. Any purchases will be made on a discretionary basis in the open market or otherwise at times and in amounts as determined by management subject to market conditions, legal requirements and other factors. Since the date of authorization, we have not purchased any shares of our common stock under this program. Based on the refinancing of certain credit facilities in March 2003, we are restricted from purchasing treasury stock, see note 21(a).

(c) Treasury Stock Issuances and Transfers.

We did not issue or transfer any treasury stock during 2001. During 2002, we issued 1,326,843 shares of treasury stock to employees under our employee stock purchase plan. In addition, during 2002, we transferred 308,936 shares of treasury stock to our employee savings plan and issued 165,455 shares of treasury stock to fund a portion of our restricted stock awards. See note 12(a) for further discussion.

(11) EARNINGS PER SHARE

The following table presents Reliant Resources' basic and diluted earnings (loss) per share (EPS) calculation for 2001 and 2002. There were no dilutive reconciling items to net income (loss).

	Year Ended December 31, 2001	Year Ended December 31, 2002
	(shares in thousands)	
Diluted Weighted Average Shares Calculation:		
Weighted average shares outstanding	277,144	289,953
Plus: Incremental shares from assumed conversions:		
Stock options	2	—
Restricted stock	244	—
Employee stock purchase plan	83	—
Weighted average shares assuming dilution	277,473	289,953
Basic and Diluted EPS:		
Income (loss) before cumulative effect of accounting change	$ 2.02	$ (1.12)
Cumulative effect of accounting change, net of tax	0.01	(0.81)
Net income (loss)	$ 2.03	$ (1.93)

For 2001, the computation of diluted EPS excludes purchase options for 8,528,098 shares of common stock that have an exercise price (ranging from $23.20 to $34.03) greater than the per share average market price ($22.11) for the period and would thus be anti-dilutive if exercised.

For 2002, as we incurred a loss from continuing operations, we do not assume any potentially dilutive shares in the computation of diluted EPS. The computation of diluted EPS excludes incremental shares from assumed

conversions for stock options of 273,921 shares, restricted stock of 1,120,865 shares, and employee stock purchase plan rights of 132,580 shares for 2002. These incremental shares from assumed conversions exclude purchase options for 15,875,183 shares of common stock that have an exercise price (ranging from $8.50 to $34.03) greater than the per share average market price ($8.15) for the period and would thus be anti-dilutive if exercised.

Prior to August 9, 2000, Reliant Resources, Inc. was not a separate legal entity and therefore had no historical capital structure. Accordingly, earnings per share have not been presented for 2000.

Reliant Resources' Certificate of Incorporation was amended to affect a 240,000 to 1 stock split of our common stock on January 5, 2001.

(12) STOCK-BASED INCENTIVE COMPENSATION PLANS AND RETIREMENT PLANS

(a) Stock-Based Incentive Compensation Plans.

At December 31, 2002, our eligible employees participate in four incentive plans described below.

The Long-Term Incentive Plan of Reliant Resources, Inc. (2001 LTIP) and Reliant Resources, Inc. 2002 Long-Term Incentive Plan (2002 LTIP) permit us to grant awards (stock options, restricted stock, stock appreciation rights, performance awards and cash awards) to all of our employees, non-employee directors and other eligible individuals. Subject to adjustment as provided in each plan, the aggregate number of shares of our common stock that may be issued under each plan may not exceed 16,000,000 shares and 17,500,000 shares, respectively. Upon the adoption of the 2002 LTIP plan, the shares remaining available for grant under the 2001 LTIP, totaling approximately 3.5 million, were effectively cancelled and considered in determining the authorized shares available for grant under the 2002 LTIP.

The Reliant Resources, Inc. 2002 Stock Plan (2002 Stock Plan) permits us to grant awards (stock options, restricted stock, stock appreciation rights, performance awards and cash awards) to all of our employees (excluding officers). The shares available for grant are based on the 6,000,000 shares authorized upon adoption of the 2002 Stock Plan plus an additional number of shares to be added to the plan on January 1st of each year, adjusted for new grants, exercises, forfeitures, cancellations and terminations of outstanding awards under the plan throughout the year.

Prior to the IPO, eligible employees participated in a CenterPoint Long-Term Incentive Compensation Plan and other incentive compensation plans (collectively, the CenterPoint Plans) that provided for the issuance of stock-based incentives including performance-based shares, restricted shares, stock options and stock appreciation rights, to key employees including officers. The Reliant Resources, Inc. Transition Stock Plan (Transition Plan) was adopted to govern the outstanding restricted shares and options of CenterPoint common stock held by our employees prior to the Distribution date, under the CenterPoint Plans. There were 9,100,000 shares authorized under the Transition Plan and as of December 31, 2002, no additional shares will be issued.

In addition, in conjunction with the Distribution, we entered into an employee matters agreement with CenterPoint. This agreement covered the treatment of outstanding CenterPoint equity awards (including performance-based shares, restricted shares and stock options) under the CenterPoint Plans held by our employees and CenterPoint employees. According to the agreement, each CenterPoint equity award granted to our employees and CenterPoint employees prior to the agreed upon date of May 4, 2001, that was outstanding

under the CenterPoint Plans as of the Distribution date, was adjusted. This adjustment resulted in each individual, who was a holder of a CenterPoint equity award, receiving an adjusted equity award of our common stock and CenterPoint common stock, immediately after the Distribution. The combined intrinsic value of the adjusted CenterPoint equity awards and our equity awards, immediately after the record date of the Distribution, was equal to the intrinsic value of the CenterPoint equity awards immediately before the record date of the Distribution.

Performance-based Shares and Restricted Shares. Performance-based shares and restricted shares have been granted to employees without cost to the participants. The performance-based shares generally vest three years after the grant date based upon performance objectives over a three-year cycle, except as discussed below. The restricted shares vest to the participants at various times ranging from immediate vesting to vesting at the end of a five-year period. During 2000, 2001 and 2002, we recorded compensation expense of $6.7 million, $8.2 million and $3.6 million, respectively, related to performance-based and restricted share grants.

Prior to the Distribution, our employees and CenterPoint employees held outstanding performance-based shares and restricted shares of CenterPoint's common stock under the CenterPoint Plans. On the Distribution date, each performance-based share of CenterPoint common stock outstanding under the CenterPoint Plans, for the performance cycle ending December 31, 2002, was converted to restricted shares of CenterPoint's common stock based on a conversion ratio provided under the employee matters agreement. Immediately following this conversion, outstanding restricted shares of CenterPoint common stock were converted to restricted shares of our common stock, which shares were subject to their original vesting schedule under the CenterPoint Plans. The conversion ratio was determined using the intrinsic value approach described above. As such, our employees and CenterPoint's employees held 302,306 and 87,875 restricted shares, respectively, outstanding under CenterPoint Plans which were converted to 238,457 and 69,334 restricted shares, respectively, of our common stock, of which a majority vested on December 31, 2002.

The following table summarizes Reliant Resources' performance-based shares and restricted shares grant activity for 2001 and 2002:

	Performance-based Shares	Restricted Shares
Outstanding at December 31, 2000	—	—
Granted	693,135	156,674
Outstanding at December 31, 2001	693,135	156,674
Granted	754,182	671,803
Shares relating to conversion of CenterPoint's restricted shares at Distribution	—	307,791
Released to participants	—	(253,071)
Canceled	(361,785)	(127,930)
Outstanding at December 31, 2002	1,085,532	755,267
Weighted average grant date fair value of shares granted for 2001	$ 30.00	$ 33.11
Weighted average grant date fair value of shares granted for 2002	$ 10.59	$ 9.26

Stock Options. Under both CenterPoint's and our plans, stock options generally vest over a three-year period and expire after ten years from the date of grant. The exercise price is based on the fair market value of the applicable common stock on the grant date.

As of the record date of the Distribution, CenterPoint converted all outstanding CenterPoint stock options granted prior to May 4, 2001 (totaling 7,761,960 stock options) to a combination of CenterPoint stock options totaling 7,761,960 stock options at a weighted average exercise price of $17.84 and Reliant Resources stock options totaling 6,121,105 stock options with a weighted-average exercise price of $8.59. The conversion ratio was determined using an intrinsic value approach as described above.

The following table summarizes Reliant Resources stock option activity for 2001 and 2002:

	Options	Weighted Average Exercise Price
Outstanding at December 31, 2000	—	
Granted	8,826,432	$29.82
Canceled	(245,830)	28.28
Outstanding at December 31, 2001	8,580,602	29.86
Granted	7,141,267	10.57
Options relating to conversion of CenterPoint's stock options at Distribution	6,121,105	8.59
Canceled	(2,674,238)	22.25
Outstanding at December 31, 2002	19,168,736	16.99
Options exercisable at December 31, 2001	6,500	30.00
Options exercisable at December 31, 2002	8,232,294	16.16

The following table summarizes, with respect to Reliant Resources, the range of exercise prices and the weighted-average remaining contractual life of the options outstanding and the range of exercise prices for the options exercisable at December 31, 2002:

	Options Outstanding			Options Exercisable	
	Options Outstanding	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Options Outstanding	Weighted-Average Exercise Price
Ranges of Exercise Prices Exercisable at:					
$ 1.83-$10.00	5,607,360	$ 7.84	6.1	4,276,541	$ 8.26
$10.01-$20.00	6,636,731	11.19	8.3	1,136,293	11.66
$20.01-$34.03	6,924,645	29.95	7.5	2,819,460	29.95
Total	19,168,736	16.99	7.4	8,232,294	16.16

Of the outstanding and exercisable stock options as of December 31, 2002, 17,438,954 and 6,931,212, respectively, relate to our employees. The remainder of outstanding and exercisable stock options as of December 31, 2002, primarily relate to employees of CenterPoint.

Exercise prices for CenterPoint stock options outstanding and held by our employees ranged from $12.87 to $36.25. The following table provides information with respect to outstanding and exercisable CenterPoint stock options held by our employees at December 31, 2001 and 2002:

	December 31, 2001		December 31, 2002	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding	5,886,119	$24.81	5,449,021	$18.05
Exercisable	2,683,755	25.62	4,535,211	18.28

Employee Stock Purchase Plan. In the second quarter 2001, we established the Reliant Resources, Inc. Employee Stock Purchase Plan (ESPP) under which we are authorized to sell up to 3,000,000 shares of our common stock to our employees. Under the ESPP, employees may contribute up to 15% of their compensation, as defined, towards the purchase of shares of our common stock at a price of 85% of the lower of the market value at the beginning of the offering period or end of each six-month offering period. The initial purchase period began on the date of the IPO and ended December 31, 2001. The market value of the shares acquired in any year may not exceed $25,000 per individual. Under the ESPP, 550,781 shares, 776,062 shares and 717,931 shares of our common stock were sold to employees at a price of $14.07, $7.44 and $2.66 per share related to the January 2002, July 2002 and January 2003 purchase, respectively.

Pro Forma Effect on Net Income (Loss). In accordance with SFAS No. 123, we apply the intrinsic value method contained in APB No. 25 and disclose the required pro forma effect on net income (loss) and earnings (loss) per share as if the fair value method of accounting for stock compensation was used. The weighted average grant date fair value for an option to purchase our common stock granted during 2001 and 2002 was $13.35 and $5.09, respectively. The weighted average grant date fair value of a purchase right issued under our ESPP during 2001 and 2002 was $9.24 and $4.51, respectively. The weighted average grant date fair value for an option to purchase CenterPoint common stock granted during 2000 and 2001 was $5.07 and $9.25, respectively. The fair values were estimated using the Black-Scholes option valuation model with the following weighted-average assumptions:

	Reliant Resources Stock Options	
	2001	2002
Expected life in years	5	5
Risk-free interest rate	4.94%	4.43%
Estimated volatility	42.65%	46.99%
Expected common stock dividend	0%	0%

	Reliant Resources Purchase Rights under ESPP	
	2001	2002
Expected life in months	8	6
Risk-free interest rate	3.92%	1.89%
Estimated volatility	46.48%	71.32%
Expected common stock dividend	0%	0%

	CenterPoint Stock Options	
	2000	2001
Expected life in years	5	5
Risk-free interest rate	6.57%	4.87%
Estimated volatility of CenterPoint common stock	24.00%	31.91%
Expected common stock dividend	3.46%	5.75%

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options, which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because our employee stock options and purchase rights have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in our opinion, the existing models do not necessarily provide a reliable single measure of the fair value of our employee stock options and purchase rights.

For the pro forma computation of net income (loss) and earnings (loss) per share as if the fair value method of accounting had been applied to all stock awards, see note 2(h).

(b) Pension.

We sponsor multiple noncontributory defined benefit pension plans covering certain union and non-union employees. Depending on the plan, the benefit payment is either based on years of service with final average salary and covered compensation, or in the form of a cash balance account which grows based on a percentage of annual compensation and accrued interest.

Prior to March 1, 2001, we participated in CenterPoint's noncontributory cash balance pension plan. Effective March 1, 2001, we no longer accrued benefits under this noncontributory pension plan for our domestic non-union employees (Resources Participants). Effective March 1, 2001, each Resources Participant's unvested pension account balance became fully vested and a one-time benefit enhancement was provided to some qualifying participants. During the first quarter of 2001, we incurred a charge to earnings of $83 million (pre-tax) for a one-time benefit enhancement and a gain of $23 million (pre-tax) related to the curtailment of CenterPoint's pension plan. In connection with the Distribution, we incurred a loss of $65 million (pre-tax) related to the accounting settlement of the pension obligation. In connection with recording the accounting settlement, CenterPoint contributed certain benefit plan deferred losses, net of taxes, totaling $18 million that were deemed to be associated with our benefit obligation. Upon the Distribution, we effectively transferred to CenterPoint our pension obligation. After the Distribution, each Resources Participant may elect to have his accrued benefit (a) left in the CenterPoint pension plan for which CenterPoint is the plan sponsor, (b) rolled over to our savings plan or an individual retirement account, or (c) paid in a lump-sum or annuity distribution.

Our funding policy is to review amounts annually in accordance with applicable regulations in order to achieve adequate funding of projected benefit obligations. The assets of the pension plans consist principally of short-term investments, common stocks and high-quality, interest-bearing obligations.

REPGB is a foreign subsidiary and participates along with other companies in the Netherlands in making payments to pension funds, which are not administered by us. We treat these as a defined contribution pension plan which provides retirement benefits for most of our REPGB employees. The contributions are principally

based on a percentage of the employee's base compensation and charged against income as incurred. This expense was $6 million, $6 million and $5 million for 2000, 2001 and 2002, respectively.

Net pension cost (excluding REPGB) includes the following components:

	Year Ended December 31,		
	2000	2001	2002
	(in millions)		
Service cost—benefits earned during the period	$ 3.6	$ 3.5	$ 6.4
Interest cost on projected benefit obligation	2.1	8.2	10.1
Expected return on plan assets	(3.3)	(11.9)	(12.9)
Curtailment and benefits enhancements	—	44.9	0.6
Accounting settlement charge	—	—	64.9
Net amortization	(0.3)	0.6	0.1
Net pension cost	$ 2.1	$ 45.3	$ 69.2

The significant weighted-average assumptions include the following:

	Year Ended December 31,		
	2000	2001	2002
Discount rate	7.5%	7.25%	6.75%
Rate of increase in compensation levels	3.5-5.5%	3.5-5.5%	4.0-4.5%
Expected long-term rate of return on assets	10.0%	9.5%	8.5%

Following are reconciliations of our beginning and ending balances of our retirement plans' benefit obligation, plans' assets and funded status for 2001 and 2002 (excluding REPGB). The prepaid pension asset as of December 31, 2001 was primarily recorded in other long-term assets.

	Year Ended December 31, 2001	Year Ended December 31, 2002
	(in millions)	
Change in Benefit Obligation		
Benefit obligation, beginning of year	$ 28.7	$ 137.6
Service cost	3.5	6.4
Interest cost	8.2	10.1
Curtailments and benefits enhancement	55.8	0.6
Transfers from affiliates	35.4	(125.7)
Acquisitions	—	39.8
Benefits paid	—	(6.2)
Plan amendments	—	2.0
Actuarial loss	6.0	7.9
Benefit obligation, end of year	$137.6	$ 72.5
Change in Plans Assets		
Plans assets, beginning of year	$ 27.3	$ 152.8
Transfers/allocations from affiliates	124.8	(147.0)
Employer contributions	0.7	7.8
Benefits paid	—	(6.2)
Acquisitions	—	20.9
Actual investment return	—	1.2
Plans assets, end of year	$152.8	$ 29.5
Reconciliation of Funded Status		
Funded status	$ 15.2	$ (43.0)
Unrecognized transition asset	(0.2)	—
Unrecognized prior service cost	—	2.0
Unrecognized actuarial loss	14.8	18.2
Net amount recognized at end of year	$ 29.8	$ (22.8)

As all distributions from the CenterPoint noncontributory plan to Resources Participants after the Distribution will be made from CenterPoint plan assets, actual investment returns on those plan assets above or below expected returns on those plan assets are included in "transfers/allocations from affiliates" in the above reconciliation in 2001.

The projected benefit obligation, accumulated benefit obligation, and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $70.9 million, $48.7 million and $28.0 million, respectively, as of December 31, 2002. The projected benefit obligation, accumulated benefit obligation, and fair value of plan assets for one of our pension plans, which had accumulated benefit obligations in excess of plan assets as of December 31, 2001, was $6.6 million, $4.7 million and $1.7 million, respectively.

The actuarial loss during 2002 was primarily due to the decrease in the economic assumptions used to value the benefit obligations as well as discount rate and changes in demographics of the participants.

Prior to the Distribution, we participated in CenterPoint's non-qualified pension plan which allowed participants to retain the benefits to which they would have been entitled under CenterPoint's qualified noncontributory pension plan except for the federally mandated limits on these benefits or on the level of salary on which these benefits may be calculated. Effective March 1, 2001, we no longer provide future non-qualified pension benefits to our employees. In connection with the Distribution, we assumed CenterPoint's obligation under the non-qualified pension plan. The expense associated with this non-qualified plan was $0.2 million, $2 million and $3 million in 2000, 2001 and 2002, respectively. The accrued benefit liability for the non-qualified pension plan was $30 million and $19 million as of December 31, 2001 and 2002, respectively. In addition, the accrued benefit liabilities as of December 31, 2001 and 2002 include the recognition of minimum liability adjustments of $11 million and $4 million, respectively, which is reported as a component of comprehensive income (loss), net of income tax effects. After the Distribution, participants in the non-qualified pension plan were given the opportunity to elect to receive distributions or have their account balance funded into a rabbi trust. Accordingly, $14 million of the non-qualified pension plan account balances were transferred to the rabbi trust, as discussed below.

(c) Savings Plan.

We have employee savings plans that are tax-qualified plans under Section 401(a) of the Internal Revenue Code of 1986, as amended (Code), and include a cash or deferred arrangement under Section 401(k) of the Code for substantially all our employees except for our foreign subsidiaries' employees. Prior to February 1, 2002, our non-union employees, except for REMA non-union employees and our foreign subsidiaries' employees, participated in CenterPoint's employee savings plan that is a tax qualified plan under Section 401(a) of the Code, and included a cash or deferred arrangement under Section 401(k) of the Code.

Under the various plans, participating employees may contribute a portion of their compensation, pre-tax or after-tax, generally up to a maximum of 16% of compensation with the exception of the Orion Power savings plan which contributions are generally up to a maximum of 18% of compensation. Our savings plans match and any payroll period discretionary employer contribution will be made in cash; any discretionary annual employer contribution, as applicable, may be made in our common stock, cash or both. All prior and future employer contributions on behalf of such employees are fully vested, except some of Orion Power employees' employer matching contributions, which may be subject to a vesting schedule, and except some union employees as defined in their collective bargaining agreement. Through March 1, 2001, a substantial portion of CenterPoint's employee savings plan match was made in CenterPoint common stock.

Our savings plans benefit expense was $6 million, $20 million and $24 million in 2000, 2001 and 2002, respectively.

(d) Postretirement Benefits.

Effective March 1, 2001, we discontinued providing subsidized postretirement benefits to our domestic non-union employees. We incurred a pre-tax loss of $40 million during the first quarter of 2001 related to the curtailment of our postretirement obligation. In connection with the Distribution, we incurred a pre-tax gain of $18 million related to the accounting settlement of postretirement benefit obligations. Prior to March 1, 2001, through a CenterPoint subsidized postretirement plan, we provided some postretirement benefits for substantially all of our retired employees. We continue to provide subsidized postretirement benefits to certain union employees and Orion Power employees. REPGB provides some postretirement benefits (primarily medical care and life insurance benefits) for its retired employees, substantially all of who may become eligible for these benefits when they retire. We fund our portion of the postretirement benefits on a pay-as-you-go basis.

Net postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2000	2001	2002
	(in millions)		
Service cost—benefits earned during the period	$ 1.4	$ 2.0	$ 4.4
Interest cost on projected benefit obligation	2.0	2.7	5.1
Curtailment charge	—	39.5	—
Accounting settlement gain	—	—	(17.6)
Net amortization	0.4	0.1	0.3
Net postretirement benefit cost (benefit)	$ 3.8	$44.3	$ (7.8)

The significant assumptions include the following:

	Year Ended December 31,		
	2000	2001	2002
Discount rate	6.6-7.5%	6.6-7.25%	6.6-6.75%
Rate of increase in compensation levels	2.0%	2.0%	3.5-4.5%

Following are reconciliations of our beginning and ending balances of our postretirement benefit plans' benefit obligation and funded status for 2001 and 2002:

	Year Ended December 31,	
	2001	2002
	(in millions)	
Change in Benefit Obligation		
Benefit obligation, beginning of year	$ 35.0	$ 48.5
Service cost	2.0	4.4
Interest cost	2.7	5.1
Benefit payments	(1.4)	(1.1)
Transfers from affiliates	9.8	—
Acquisitions	—	31.0
Plan amendments	—	9.5
Foreign exchange impact	(2.5)	6.0
Accounting settlement gain	—	(22.2)
Actuarial loss	2.9	4.8
Benefit obligation, end of year	$ 48.5	$ 86.0
Reconciliation of Funded Status		
Funded status	$(48.5)	$(86.0)
Unrecognized prior service cost	—	9.5
Unrecognized actuarial loss	5.7	6.6
Net amount recognized at end of year	$(42.8)	$(69.9)

In 2001, we assumed health care rate increases of 9.0% that gradually decline to 5.5% by 2010. In 2002, we assumed health care rate increases of 12.0% that gradually decline to 5.5% by 2012. The actuarial loss is due to changes in actuarial assumptions.

If the health care cost trend rate assumptions were increased by 1%, the accumulated postretirement benefit obligation as of December 31, 2002 would increase by approximately 18.2%. The annual effect of the 1% increase on the total of the service and interest costs would be an increase of approximately 17.1%. If the health care cost trend rate assumptions were decreased by 1%, the accumulated postretirement benefit obligation as of December 31, 2002 would decrease by approximately 14.5%. The annual effect of the 1% decrease on the total of the service and interest costs would be a decrease of 14.1%.

During 2002, the retiree medical benefits for certain union employees were redesigned to allow for a company-provided subsidy for premium coverage attributable to qualifying employees. This resulted in a $9.5 million increase in the accumulated postretirement benefit obligation during 2002.

(e) Postemployment Benefits.

We record postemployment benefits based on SFAS No. 112, "Employer's Accounting for Postemployment Benefits," which requires the recognition of a liability for benefits provided to former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily health care and life insurance benefits for participants in the long-term disability plan). Net postemployment benefit costs were insignificant for 2000, 2001 and 2002.

(f) Other Non-qualified Plans.

Effective January 1, 2002, select key and highly compensated employees are eligible to participate in our non-qualified deferred compensation and restoration plan. The plan allows eligible employees to elect to defer up to 80% of their annual base salary and/or up to 100% of their eligible annual bonus. In addition, the plan allows participants to retain the benefits which they would have been entitled to under our qualified savings plans, except for the federally mandated limits on these benefits or on the level of salary on which these benefits may be calculated. We fund these deferred compensation and restoration liabilities by making contributions to a rabbi trust. Plan participants direct the allocation of their deferrals and restoration benefits between one or more of our designated investment funds within the rabbi trust.

Through 2001, certain eligible employees participated in CenterPoint's deferred compensation plans, which permit participants to elect each year to defer a percentage of that year's salary and up to 100% of that year's annual bonus. Interest generally accrued on deferrals made in 1989 and subsequent years at a rate equal to the average Moody's Long-Term Corporate Bond Index plus 2%, determined annually until termination when the rate is fixed at the greater of the rate in effect at age 64 or at age 65. Fixed rates of 19% to 24% were established for deferrals made in 1985 through 1988. We recorded interest expense related to these deferred compensation obligations of $1 million, $4 million and $2 million in 2000, 2001 and 2002, respectively. Each of our employees that participated in this plan has elected to have his CenterPoint non-qualified deferred compensation plan account balance, after the Distribution: (a) paid in a lump-sum distribution, (b) placed in a new deferred compensation plan established by us, which generally mirrors the former CenterPoint deferred compensation plans, or (c) rolled over to our deferred compensation and restoration plan discussed above.

Our discounted deferred compensation obligation recorded by us was $29 million as of December 31, 2001 related to the CenterPoint deferred compensation plan. Our discounted deferred compensation obligation related to the deferred compensation obligation under the plan that mirrors the CenterPoint plan was $12 million as of December 31, 2002. Our deferred compensation and restoration liability related to the deferred compensation and restoration plan established effective January 1, 2002 (discussed above) was $23 million and the related investment in the rabbi trust was $23 million as of December 31, 2002.

(g) Other Employee Matters.

As of December 31, 2002, approximately 32% of our employees are subject to collective bargaining arrangements, of which contracts covering 6% of our employees will expire prior to December 31, 2003.

(13) INCOME TAXES

The components of income (loss) before income taxes, cumulative effect of accounting change and extraordinary item are as follows:

	Year Ended December 31, 2000	2001	2002
	(in millions)		
United States	$198.5	$729.2	$ 215.3
Foreign	112.6	105.5	(327.4)
Income (loss) before income taxes, cumulative effect of accounting change and extraordinary item	$311.1	$834.7	$(112.1)

Our current and deferred components of income tax expense (benefit) were as follows:

	Year Ended December 31, 2000	2001	2002
	(in millions)		
Current			
Federal	$106.5	$240.8	$(74.9)
State	16.9	3.8	31.9
Foreign	—	(2.7)	2.0
Total current	123.4	241.9	(41.0)
Deferred			
Federal	(28.2)	20.8	204.5
State	0.7	15.7	(4.7)
Foreign	—	(4.0)	55.3
Total deferred	(27.5)	32.5	255.1
Income tax expense	$ 95.9	$274.4	$214.1

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	Year Ended December 31,		
	2000	2001	2002
		(in millions)	
Income (loss) before income taxes	$311.1	$834.7	$(112.1)
Federal statutory rate	35%	35%	35%
Income tax expense at statutory rate	108.9	292.1	(39.2)
Net addition (reduction) in taxes resulting from:			
State income taxes, net of valuation allowances and federal income tax benefit	11.4	12.7	17.7
European energy goodwill impairment	—	—	168.7
REPGB tax holiday	(37.8)	(49.9)	(5.1)
Goodwill amortization	2.1	8.6	—
Federal and foreign valuation allowance	12.8	3.3	22.6
Future distributions from foreign equity investment	—	—	44.6
Other, net	(1.5)	7.6	4.8
Total	(13.0)	(17.7)	253.3
Income tax expense	$ 95.9	$274.4	$ 214.1
Effective rate	30.8%	32.9%	NM(1)

(1) Not meaningful as we had a pre-tax loss of $112.1 million and income tax expense of $214.1 million. The primary reason is due to the European energy segment's goodwill impairment of $482 million, for which no tax benefit can be recognized as the goodwill is non-deductible.

REPGB Tax Holiday. Under 1998 Dutch tax law relating to the Dutch electricity industry, REPGB qualifies for a zero percent tax rate through December 31, 2001. The tax holiday applies only to the Dutch income earned by REPGB. Beginning January 1, 2002, REPGB is subject to Dutch corporate income tax at standard statutory rates, which is currently 34.5%, which was enacted in 2001. Prior to 2001, the enacted rate was 35%. During 2002, there was a $5.1 million reconciling item as a result of the tax holiday as the results of our European energy segment are consolidated on a one-month-lag basis. The effect of the change in the enacted tax rate was not material to our results of operations.

Future Distributions from Foreign Equity Investments. During 2002, we accrued a $46 million United States federal tax provision for future cash distributions from our equity investment in NEA. Based on our current tax position, during 2002, we determined that we would be obligated to pay United States taxes on future cash distributions from NEA in excess of our tax basis. As of December 31, 2002, our investment in NEA was $210 million. For further discussion of our investment in NEA, see notes 8 and 14(j).

Undistributed Earnings of Foreign Subsidiaries. The undistributed earnings of foreign subsidiaries aggregated $266 million and $319 million as of December 31, 2001 and 2002, respectively, which, under existing tax law, will not be subject to United States income tax until distributed. Provisions for United States income taxes have not been accrued on these undistributed earnings, as these earnings have been, or are intended to be, permanently reinvested. In the event of a distribution of these earnings in the form of dividends, we will be subject to United States income taxes net of allowable foreign tax credits.

Following were our tax effects of temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and their respective tax bases:

	Year Ended December 31, 2001	Year Ended December 31, 2002
	(In millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts and credit provisions	$ 59.5	$ 30.7
Contractual rights and obligations	—	13.7
Adjustment to fair value for debt	—	10.9
Operating loss carryforwards	—	66.6
Other	4.8	7.0
Total current deferred tax assets	64.3	128.9
Non-current:		
Employee benefits	44.3	55.3
Operating loss carryforwards	18.1	75.5
Environmental reserves	15.0	26.5
Foreign exchange gains	11.1	11.6
Non-trading derivative liabilities, net	133.7	24.5
Non-derivative stranded costs liability	73.1	—
Accrual for payment to CenterPoint Energy, Inc	—	48.7
Adjustment to fair value for debt	—	50.4
Equity method investments	4.0	10.0
Other	26.1	31.2
Valuation allowance	(15.6)	(71.3)
Total non-current deferred tax assets	309.8	262.4
Total deferred tax assets	$374.1	$ 391.3
Deferred tax liabilities:		
Current:		
Trading and marketing assets, net	$ 48.4	$ 37.0
Non-trading derivative assets, net	0.8	23.7
Hedges of net investment in foreign subsidiaries	52.1	20.6
Other	—	7.3
Total current deferred tax liabilities	101.3	88.6
Non-current:		
Depreciation and amortization	133.6	653.6
Trading and marketing assets, net	27.5	25.9
Stranded costs indemnification receivable	73.1	—
Contractual rights and obligations	—	10.3
Future distributions from foreign equity investment	—	46.4
Other	29.3	25.8
Total non-current deferred tax liabilities	263.5	762.0
Total deferred tax liabilities	$364.8	$ 850.6
Accumulated deferred income taxes, net	$ 9.3	$(459.3)

Tax Attribute Carryovers. At December 31, 2002, we had approximately $184 million, $893 million, $144 million and $0.5 million of federal, state and foreign net operating loss carryovers and capital loss carryforwards, respectively. The federal and state loss carryforwards can be carried forward to offset future income through the year 2022. The foreign losses can be carried forward indefinitely.

The valuation allowance reflects a net decrease of $5 million in 2001 and a $56 million net increase in 2002. The net increase in 2002 results primarily from increased state and foreign net operating losses and impairments on capital assets. In addition, in connection with the Orion Power acquisition, we recorded a valuation allowance of $30 million due to state net operating losses. These net changes for 2001 and 2002 also resulted from a reassessment of our future ability to use federal, state and foreign tax net operating loss and capital loss carryforwards.

As discussed in note 14(j), the Dutch parliament has adopted legislation allocating to the Dutch generation sector, including REPGB, financial responsibility for certain stranded costs and other liabilities incurred by NEA prior to the deregulation of the Dutch wholesale market. These obligations include NEA's obligations under a stranded cost gas supply contract and three stranded cost electricity contracts. As a result, we recorded an out-of-market, net stranded cost liability of $369 million and a related deferred tax asset of $127 million at December 31, 2001 for our statutorily allocated share of these gas supply and electricity contracts. Prior to 2002, we believed that the costs incurred by REPGB subsequent to the tax holiday ending in 2001 related to these contracts would be deductible for Dutch tax purposes. However, due to the uncertainties related to the deductibility of these costs, we recorded an offsetting liability in other liabilities of $127 million as of December 31, 2001. We now believe, based upon discussions with the Dutch tax authorities in 2002, obtaining a tax deduction for these costs will require litigation in the Netherlands, and accordingly, we reversed both the deferred tax asset and related liability in 2002.

(14) COMMITMENTS AND CONTINGENCIES

(a) Lease Commitments.

In August 2000, we entered into separate sale-leaseback transactions with each of three owner-lessors' respective 16.45%, 16.67% and 100% interests in the Conemaugh, Keystone and Shawville generating stations, respectively, acquired in the REMA acquisition. As lessee, we lease an interest in each facility from each owner-lessor under a facility lease agreement. We expect to make lease payments through 2029 under these leases, with total cash payments of $1.4 billion remaining as of December 31, 2002. The lease terms expire in 2034. The equity interests in all the subsidiaries of REMA are pledged as collateral for REMA's lease obligations and the subsidiaries have guaranteed the lease obligations. Additionally, each of the lease obligations is backed by an uncollateralized, irrevocable, unconditional stand-by letter of credit, see note 9(a). In connection with the sale-leaseback transactions, we also issued three series of pass through certificates, which represent undivided interests in three pass through trusts. The property of each pass through trust consists solely of nonrecourse secured lease obligation notes or lessor notes. The amounts payable by REMA under the leases are sufficient to pay all payments of principal and premium, if any, and interest on the lessor notes. The lessor notes are secured by the relevant leased facility, the lease documents, and the security for the lease obligations.

The lease documents contain restrictive covenants that restrict REMA's ability to, among other things, make dividend distributions unless REMA satisfies various conditions. The covenant restricting dividends would be suspended if the direct or indirect parent of REMA, meeting specified criteria, including having a rating on REMA's long-term unsecured senior debt of at least BBB from Standard and Poor's and Baa2 from Moody's, guarantees the lease obligations. As of December 31, 2001, REMA had $167 million of restricted funds that were

available for REMA's working capital needs and to make future lease payments. As of December 31, 2002, the various conditions were satisfied by REMA and there was no restricted cash.

In the first quarter of 2001, we entered into tolling arrangements with a third party to purchase the rights to utilize and dispatch electric generating capacity of approximately 1,100 MW extending through 2012. Two gas-fired, simple-cycle peaking plants generate this electricity. We did not pay any amounts under these tolling arrangements during 2001. We paid $45 million in tolling payments during 2002. The tolling arrangements qualify as operating leases.

In February 2001, CenterPoint entered into a lease for office space for us in a building under construction. CenterPoint assigned the lease agreement to us in June 2001. The lease term, which commences in the second quarter 2003, is 15 years with two five-year renewal options.

The following table sets forth information concerning our cash obligations under non-cancelable long-term operating leases as of December 31, 2002. Other non-cancelable, long-term operating leases principally consist of tolling arrangements, as discussed above, rental agreements for building space, including the office space lease discussed above, data processing equipment and vehicles, including major work equipment:

	REMA Sale-Lease Obligation	Other	Total
	(in millions)		
2003	$ 77	$ 85	$ 162
2004	84	91	175
2005	75	89	164
2006	64	87	151
2007	65	62	127
2008 and beyond	1,059	390	1,449
Total	$1,424	$804	$2,228

Total lease expense for all operating leases was $24 million, $75 million and $120 million during 2000, 2001 and 2002, respectively. During 2000, 2001 and 2002, we made lease payments related to the REMA sale-leaseback of $1 million, $259 million and $136 million, respectively. As of December 31, 2001 and 2002, we have recorded a prepaid lease obligation related to the REMA sale-leaseback of $59 million and $59 million, respectively, in other current assets and of $122 million and $200 million, respectively, in other long-term assets.

(b) Construction Agency Agreements with Off-balance Sheet Special Purpose Entities.

In 2001, we, through several of our subsidiaries, entered into operative documents with special purpose entities to facilitate the development, construction, financing and leasing of several power generation projects. We did not consolidate the special purpose entities as of December 31, 2002. As of December 31, 2002, the special purpose entities have an aggregate financing commitment from equity and debt participants (Investors) for three electric generating facilities of $1.9 billion of which the last $515 million is currently available only if cash collateralized. The availability of the $1.9 billion commitment is subject to satisfaction of various conditions, including the obligation to provide cash collateral for the loans and letters of credit outstanding on November 29, 2004. We, through several of our subsidiaries, act as construction agent for the special purpose entities and are responsible for completing construction of these projects by December 31, 2004. However, we

have generally limited our risk during construction to an amount not to exceed 89.9% of costs incurred to date, except in certain events. Upon completion of an individual project and exercise of the lease option, our subsidiaries will be required to make lease payments in an amount sufficient to provide a return to the Investors. If we do not exercise our option to lease any project upon its completion, we must purchase the project or remarket the project on behalf of the special purpose entities. Our ability to exercise the lease option is subject to certain conditions. We must guarantee that the Investors will receive an amount at least equal to 89.9% of their investment in the case of a remarketing sale at the end of construction. At the end of an individual project's initial operating lease term (approximately five years from construction completion), our subsidiary lessees have the option to extend the lease with the approval of the Investors, purchase the project at a fixed amount equal to the original construction cost, or act as a remarketing agent and sell the project to an independent third party. If the lessees elect the remarketing option, they may be required to make a payment of an amount not to exceed 85% of the project cost, if the proceeds from remarketing are not sufficient to repay the Investors. Reliant Resources has guaranteed its subsidiaries' obligations under the operative agreements during the construction periods and, if the lease option is exercised, each lessee's obligations during the lease period. At any time during the construction period or during the lease, we may purchase a facility by paying an amount approximately equal to the outstanding debt balance plus the equity balance and any returns of equity plus any accrued and unpaid financing costs or we may purchase the facility by assuming, directly or indirectly, the obligations of the subsidiaries, in which case the guarantee must remain in place and lender consent may be required. As of December 31, 2002, the special purpose entities had property, plant and equipment of $1.3 billion, net other assets of $3 million and secured debt obligations of $1.3 billion. As of December 31, 2002, $1.0 billion of the debt obligations outstanding bear interest at LIBOR plus a margin of 2.25%, while the remaining $0.3 billion of the debt obligations outstanding bear interest at a weekly floating interest rate. As of December 31, 2002, the special purpose entities had equity from unaffiliated third parties of $49 million.

Due to the early adoption of FIN No. 46 (as explained in note 2(t)), we began to consolidate these special purpose entities effective January 1, 2003. The special purpose entities' financing agreement, the construction agency agreements and the related guarantees were terminated as part of the refinancing in March 2003. For information regarding the refinancing, see note 21(a).

(c) Off-balance Sheet Equipment Financing Structure.

We, through a subsidiary, entered into an agreement with a bank whereby the bank, as owner, entered into contracts for the purchase and construction of power generation equipment and our subsidiary, or its subagent, acted as the bank's agent in connection with administering the contracts for such equipment. The agreement was terminated in September 2002. Our subsidiary, or its designee, had the option at any time to purchase, or, at equipment completion, subject to certain conditions, including the agreement of the bank to extend financing, to lease the equipment, or to assist in the remarketing of the equipment under terms specified in the agreement. We were required to cash collateralize our obligation to administer the contracts. This cash collateral was approximately equivalent to the total payments by the bank for the equipment, interest and other fees. As of December 31, 2001, we had deposits of $230 million in the collateral account.

In January 2002, the bank sold to the parties to the construction agency agreements discussed above, equipment contracts with a total contractual obligation of $258 million, under which payments and interest during construction totaled $142 million. Accordingly, $142 million of collateral deposits were returned to us. In May 2002, we were assigned and exercised a purchase option for a contract for equipment totaling $20 million under which payments and interest during construction totaled $8 million. We used $8 million of our collateral deposits to complete the purchase. After the purchase, we canceled the contract and recorded a $10 million loss

on the cancellation of the contract, which included a $2 million termination fee. Immediately prior to the expiration of the agreement in September 2002, we terminated the agreement and were assigned and exercised purchase options for contracts for steam and combustion turbines and two heat recovery steam generators with an aggregate cost of $121 million under which payments and interest during construction totaled $94 million. We used $94 million of our collateral deposits to complete the purchase.

Pursuant to SFAS No. 144, we evaluated for impairment the steam and combustion turbines and two heat recovery steam generators purchased in September 2002. Based on our analysis, we determined this equipment was impaired and accordingly recognized a $37 million pre-tax impairment loss that is recorded as depreciation expense in 2002 in our statement of consolidated operations. The fair value of the equipment and thus the impairments was determined using a combination of quoted market prices and prices for similar assets.

(d) Cross Border Leases.

During the period from 1994 through 1997, under cross border lease transactions, REPGB leased several of its power plants and related equipment and turbines to non-Netherlands based investors (the head leases) and concurrently leased the facilities back under sublease arrangements with remaining terms as of December 31, 2002 of 1 to 22 years. REPGB utilized proceeds from the head lease transactions to prepay its sublease obligations and to provide a source for payment of end of term purchase options and other financial undertakings. The initial sublease obligations totaled $2.4 billion of which $1.6 billion remained outstanding as of December 31, 2002. These transactions involve REPGB providing to a foreign investor an ownership right in (but not necessarily title to) an asset, with a leaseback of that asset. The net proceeds to REPGB of the transactions were recorded as a deferred gain and are currently being amortized to income over the lease terms. At December 31, 2001 and 2002, the unamortized deferred gain on these transactions totaled $68 million and $73 million, respectively. The power plants, related equipment and turbines remain on our consolidated financial statements and continue to be depreciated. In February 2003, we signed a share purchase agreement to sell our European energy operations to a Netherlands-based electricity distributor. See note 21(b) for discussion.

REPGB is required to maintain minimum insurance coverages, perform minimum annual maintenance and, in specified situations, post letters of credit. REPGB's shareholder is subject to some restrictions with respect to the liquidation of REPGB's shares. In the case of early termination of these contracts, REPGB would be contingently liable for some payments to the sublessors, which at December 31, 2002, are estimated to be $297 million. REPGB was required by some of the lease agreements to obtain standby letters of credit in favor of the sublessors in the event of early termination. The amount of the required letters of credit was $272 million and $355 million as of December 31, 2001 and 2002, respectively. Commitments for these letters of credit have been obtained as of December 31, 2002. As a result of REPGB's downgrade by the credit rating agencies in November 2002, we were required to increase the amounts of letters of credit posted as security. Further credit rating downgrades, if any, will not require additional letters of credit to be posted.

(e) Payment to CenterPoint in 2004.

We may be required to make a payment to CenterPoint in 2004 to the extent the affiliated retail electric provider's price to beat for providing retail electric service to residential and small commercial customers in CenterPoint's Houston service territory during 2002 and 2003 exceeds the market price of electricity. This payment is required by the Texas electric restructuring law, unless the PUCT determines, on or prior to January 1, 2004, that 40% or more of the amount of electric power that was consumed in 2000 by residential or small commercial customers, as applicable, within CenterPoint's Houston service territory is committed to be

served by retail electric providers other than us. This amount will not exceed $150 per customer, multiplied by the number of residential or small commercial customers, as the case may be, that we serve on January 1, 2004 in CenterPoint's Houston service territory, less the number of residential or small commercial electric customers, as the case may be, we serve in other areas of Texas. Currently, we believe it is probable that we will be required to make such payment to CenterPoint related to our residential customers. We believe that the payment related to our residential customers will be in the range of $160 million to $190 million (pre-tax), with a most probable estimate of $175 million. We will recognize the total obligation over the period we recognize the related revenues based on the difference between the amount of the price to beat and the estimated market price of electricity multiplied by the estimated energy sold through January 1, 2004 not to exceed the maximum cap of $150 per customer. We recognized $128 million (pre-tax) during 2002. The remainder of our estimated obligation will be recognized during 2003. In the future, we will revise our estimates of this payment as additional information about the market price of electricity and the market share that will be served by us and other retail electric providers on January 1, 2004 becomes available and we will adjust the related accrual at that time.

Currently, we believe that the 40% test for small commercial customers will be met and we will not make a payment related to those customers. If the 40% test is not met related to our small commercial customers and a payment is required, we estimate this payment would be approximately $30 million.

(f) Other Commitments.

Property, Plant and Equipment Purchase Commitments. As of December 31, 2002, we had one generating facility under construction. Total estimated cost of constructing this facility is $486 million. As of December 31, 2002, we had incurred $332 million of the total forecasted project costs. In addition to this generating facility, we are constructing facilities as construction agents under construction agency agreements. These construction agency agreements were terminated as part of the refinancing in March 2003 (see note 21(a)). See note 14(b) for further discussion of these agreements and the related special purpose entities. As of December 31, 2002, we had additional purchase commitments related to property, plant and equipment of $23 million.

Purchase Obligations for Trading and Marketing Assets and Liabilities, Excluding Derivatives Accounted for under SFAS No. 133. We have cash purchase obligations relating to our trading and marketing assets and liabilities, which are not derivatives under SFAS No. 133. In addition, we have purchase obligations relating to our trading and marketing assets and liabilities that, effective January 1, 2003, pursuant to the application of EITF No. 02-03, will be classified as "normal purchases contracts" under SFAS No. 133 and will not be marked to market through earnings (see note 2(t)). The minimum purchase obligations under these applicable contracts for the next five years and thereafter as of December 31, 2002 is as follows:

	Transportation Commitments	Purchased Power and Electric Capacity Commitments	Other Energy Commitments
		(in millions)	
2003	$20	$85	$ 8
2004	16	7	5
2005	13	—	5
2006	12	—	2
2007	7	—	—
2008 and thereafter	17	—	—
Total	$85	$92	$20

Fuel Supply, Commodity Transportation, Purchase Power and Electric Capacity Commitments. We are a party to several fuel supply contracts, commodity transportation contracts, and purchase power and electric capacity contracts, that have various quantity requirements and durations that are not classified as non-trading derivatives assets and liabilities or trading and marketing assets and liabilities in our consolidated balance sheet as of December 31, 2002, as these contracts meet the SFAS No. 133 exception to be classified as "normal purchases contracts" (see note 7) or do not meet the definition of a derivative. Minimum purchase commitment obligations under these agreements are as follows, as of December 31, 2002:

	Fuel Commitments	Transportation Commitments	Purchased Power and Electric Capacity Commitments
		(In millions)	
2003	$206	$ 83	$ 784
2004	130	106	174
2005	105	104	172
2006	22	104	176
2007	13	97	—
2008 and thereafter	214	1,117	—
Total	$690	$1,611	$1,306

Our aggregate electric capacity commitments, including capacity auction products, are for 17,000 MW, 4,202 MW, 4,420 MW, and 4,631 MW for 2003, 2004, 2005 and 2006, respectively. Included in the above purchase power and electric capacity commitments are amounts acquired from Texas Genco. For additional discussion of this commitment, see note 4(b).

The maximum duration under any individual fuel supply contract, transportation contract, purchased power and electric and gas capacity contract is 17 years, 21 years and 4 years, respectively.

Sale Commitments. As of December 31, 2002, we have sale commitments, including electric energy and capacity sale contracts and district heating contracts (see note 14(j)), which are not classified as non-trading derivative assets and liabilities or trading and marketing assets and liabilities in our consolidated balance sheet as these contracts meet the SFAS No. 133 exception to be classified as "normal sales contracts" or do not meet the definition of a derivative. The estimated minimum sale commitments under these contracts are $875 million, $446 million, $302 million, $245 million and $190 million in 2003, 2004, 2005, 2006 and 2007, respectively.

In addition, in January 2002, we began providing retail electric services to approximately 1.7 million residential and small commercial customers previously served by CenterPoint's electric utility division. Within CenterPoint's electric utility division's territory, prices that may be charged to residential and small commercial customers by our retail electric service provider are subject to a specified price (price to beat) at the outset of retail competition. The PUCT's regulations allow our retail electric provider to adjust its price to beat fuel factor based on a percentage change in the price of natural gas. In addition, the retail electric provider may also request an adjustment as a result of changes in its price of purchased energy. We can request up to two adjustments to our price to beat in each year. During 2002, we requested and the PUCT approved two such adjustments. For a discussion of the increase requested in January 2003, see note 21(d). We will not be permitted to sell electricity to residential and small commercial customers in the incumbent's traditional service territory at a price other than the price to beat until January 1, 2005, unless before that date the PUCT determines that 40% or more of the

amount of electric power that was consumed in 2000 by the relevant class of customers is committed to be served by other retail electric providers. For further information regarding the price to beat, see note 14(e).

Naming Rights to Houston Sports Complex. In October 2000, we acquired the naming rights for a football stadium and other convention and entertainment facilities included in the stadium complex. The agreement extends through 2032. In addition to naming rights, the agreement provides us with significant sponsorship rights. The aggregate cost of the naming rights will be approximately $300 million. During the fourth quarter of 2000, we incurred an obligation to pay $12 million in order to secure the long-term commitment and for the initial advertising of which $10 million was expensed in the statement of consolidated operations in 2000. Starting in 2002, we began to pay $10 million each year through 2032 for annual advertising under this agreement.

Long-term Power Generation Maintenance Agreements. We have entered into long-term maintenance agreements that cover certain periodic maintenance, including parts, on power generation turbines. The long-term maintenance agreements terminate over the next 12 to 18 years based on turbine usage. Estimated cash payments over the next five years for these agreements are as follows (in millions):

2003	$ 52
2004	30
2005	31
2006	31
2007	33
Total	$177

ANR Transportation Agreement. Prior to the merger of a subsidiary of CenterPoint and RERC Corp., a predecessor of Reliant Energy Services, Inc. (Reliant Energy Services) (a wholly-owned subsidiary) entered into a transportation agreement (ANR Agreement) with ANR Pipeline Company (ANR) that contemplated a transfer to ANR of an interest in some of RERC Corp.'s pipelines and related assets that are not a part of us. The interest represented capacity of 250 million cubic feet (Mmcf) per day. Under the ANR agreement, an ANR affiliate advanced $125 million to Reliant Energy Services. Subsequently, the parties restructured the ANR Agreement and Reliant Energy Services refunded in 1993 and 1995, a total of $84 million to ANR. As of December 31, 2001 and 2002, Reliant Energy Services had recorded $31 million and $35 million, respectively, to reflect our discounted obligation to ANR for the use of 130 Mmcf/day of capacity in some of RERC Corp.'s transportation facilities. The level of transportation will decline to 100 Mmcf/day in the year 2003 with a refund of $5 million made to ANR. The ANR Agreement will terminate in 2005 with a refund of the remaining balance of $36 million. Prior to the IPO, Reliant Energy Services and a subsidiary of CenterPoint entered into an agreement whereby the subsidiary of CenterPoint agreed to reimburse Reliant Energy Services for any transportation payments made under the ANR Agreement and for the $41 million total refund discussed above. We have recorded a note receivable from CenterPoint of $31 million and $35 million as of December 31, 2001 and 2002, respectively.

Other Commitments. In addition to items discussed in our consolidated financial statements, our other contractual commitments have various quantity requirements and durations and are not considered material either individually or in the aggregate to our results of operations or cash flows.

(g) Guarantees.

We, along with certain subsidiaries, have issued guarantees, on behalf of certain other entities, that provide financial assurance to third parties.

The following table details our various guarantees, including the maximum potential amounts of future payments, assets held as collateral and the carrying amount of the liabilities recorded on our consolidated balance sheet, if applicable, as of December 31, 2002:

Type of Guarantee	Maximum Potential Amount of Future Payments	Assets Held as Collateral	Carrying Amount of Liability Recorded on Consolidated Balance Sheet
		(in millions)	
Guarantees under construction agency agreements(1)	$1,325	$—	$—
REMA sale-leaseback operating leases(2)	818	—	—
Non-qualified benefits of CenterPoint's retirees(3)	58	—	—
Total Guarantees	$2,201	$—	$—

(1) See note 14(b) for discussion of our guarantees under the construction agency agreements. These guarantees were terminated in March 2003; see note 21(a).

(2) See note 14(a) for discussion of the guarantee of the lease obligations under the REMA sale/leaseback transactions by REMA's subsidiaries. The guarantee expires in 2034.

(3) We have guaranteed, in the event CenterPoint becomes insolvent, certain non-qualified benefits of CenterPoint's and its subsidiaries' existing retirees at the Distribution. See note 4(a).

Unless otherwise noted, failure by the primary obligor to perform under the terms of the various agreements and contracts guaranteed may result in the beneficiary requesting immediate payment from the relevant guarantor. To the extent liabilities exist under the various agreements and contracts that we or our subsidiaries guarantee, such liabilities are recorded in our consolidated balance sheet at December 31, 2002. We believe the likelihood that we would be required to perform or otherwise incur any significant losses associated with any of these guarantees is remote.

We have entered into contracts that include indemnification provisions as a routine part of our business activities. Examples of these contracts include asset purchase and sale agreements, commodity purchase and sale agreements, operating agreements, lease agreements, procurement agreements and certain debt agreements. In general, these provisions indemnify the counterparty for matters such as breaches of representations and warranties and covenants contained in the contract and/or against third party liabilities. In the case of commodity purchase and sale agreements, generally damages are limited through liquidated damages clauses whereby the parties agree to establish damages as the costs of covering any breached performance obligations. In the case of debt agreements, we generally indemnify against liabilities that arise from the preparation, administration or enforcement of the agreement. Under our indemnifications, the maximum potential amount is not estimable given that the magnitude of any claims under the indemnifications would be a function of the extent of damages actually incurred, which is not practicable to estimate unless and until the event occurs. We consider the likelihood of making any material payments under these provisions to be remote. For additional discussion of certain indemnifications by us, see notes 4(a) and 14(h).

(h) Environmental and Legal Matters.

We are involved in environmental and legal proceedings before various courts and governmental agencies, some of which involve substantial amounts. In addition, we are subject to a number of ongoing investigations by various governmental agencies. Certain of these proceedings and investigations are the subject of intense, highly charged media and political attention. As these matters progress, additional issues may be identified that could expose us to further proceedings and investigations. Our management regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters that can be estimated.

We have an agreement with CenterPoint that requires us to indemnify CenterPoint for matters relating to our business and operations prior to the Distribution, as well as for any untrue statement of a material fact, or omission of a material fact necessary to make any statement not misleading, in the registration statement or prospectus that we filed with the SEC in connection with our IPO. CenterPoint has been named as a defendant in many legal proceedings relative to such matters and has requested indemnification from us.

Legal Matters.

Unless otherwise indicated, the ultimate outcome of the following lawsuits, proceedings and investigations cannot be predicted at this time. The ultimate disposition of some of these matters could have a material adverse effect on our financial condition, results of operations and cash flows.

California Class Actions. We, as well as certain of our present and former officers, have been named as defendants in a number of class action lawsuits in California. The plaintiffs allege that we conspired to increase the price of wholesale electricity in California in violation of California's antitrust and unfair and unlawful business practices laws. The lawsuits seek injunctive relief, treble the amount of damages alleged, restitution of alleged overpayments, disgorgement of alleged unlawful profits for sales of electricity, costs of suit and attorneys' fees. In general, these lawsuits can be segregated into two groups based on their pre-trial status. The first group consists of (a) three lawsuits filed in the Superior Court of the State of California, San Diego County filed on November 27, 2000, November 29, 2000 and January 16, 2001; (b) two lawsuits filed in the Superior Court of the State of California, San Francisco County on January 18, 2001 and January 24, 2001; and (c) one lawsuit filed in the Superior Court of the State of California, Los Angeles County on May 2, 2001. These six lawsuits were consolidated and removed to the United States District Court for the Southern District of California. In December 2002, the court ordered these six lawsuits be remanded to state court for further consideration. We, and our co-defendants, filed a petition with the United States Court of Appeals for the Ninth Circuit seeking a review of the order to remand. The petition is under consideration by the court. The second group consists of two lawsuits filed in the Superior Court of the State of California, San Mateo County filed on April 23, 2002 and May 15, 2002, two lawsuits filed in the Superior Court of the State of California, San Francisco County on May 14, 2002 and May 24, 2002, two lawsuits filed in the Superior Court of the State of California, Alameda County on May 21, 2002, one lawsuit filed in the Superior Court of the State of California, San Joaquin County on May 10, 2002 and one lawsuit filed in the Superior Court of the State of California, Los Angeles County on October 18, 2002. These eight lawsuits were consolidated in the United States District Courts, six of which were removed to the United States District Court for the Northern District of California, one was removed to the United States District Court for the Eastern District of California, and one was removed to the United States District Court for the Central District of California. Additionally, on July 15, 2002, the Snohomish County Public Utility District filed a class action lawsuit against us in United States District Court for the Central District of California. In January 2003, the court granted our motion to dismiss this lawsuit on the

grounds that the plaintiffs' claims are barred by federal preemption and the FERC filed rate doctrine. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit.

Oregon Class Actions. On December 16, 2002, a class action lawsuit was filed against us in the Circuit Court of the State of Oregon, County of Multnomah. The plaintiffs allege that we conspired to increase the price of wholesale electricity in Oregon in violation of Oregon's consumer protection, fraud and negligence laws. The lawsuit seeks injunctive relief, treble the amount of damages alleged, restitution of alleged overpayments, disgorgement of alleged unlawful profits for sales of electricity, costs of suit and attorneys' fees. This lawsuit was removed to the United States District Court for the Northern District of California.

Washington Class Actions. On December 20, 2002, a class action lawsuit was filed against us in United States District Court for the Western District of Washington. The plaintiffs allege that we conspired to increase the price of wholesale electricity in Washington in violation of Washington's consumer protection, fraud and negligence laws. The lawsuit seeks injunctive relief, treble the amount of damages alleged, restitution of alleged overpayments, disgorgement of alleged unlawful profits for sales of electricity, costs of suit and attorneys' fees.

California Attorney General Actions. On March 11, 2002, the California Attorney General filed a lawsuit against us in Superior Court of the State of California, San Francisco County. The California Attorney General alleges various violations of state laws against unfair and unlawful business practices arising out of transactions in the markets for ancillary services run by the California Independent System Operator (Cal ISO). The lawsuit seeks injunctive relief, disgorgement of our alleged unlawful profits for sales of electricity and civil penalties. We removed this lawsuit to the United States District Court for the Northern District of California. In March 2003, the court granted our motion to dismiss this lawsuit on the grounds that the plaintiffs' claims are barred by federal preemption and the FERC filed rate doctrine.

On March 19, 2002, the California Attorney General filed a complaint against us with the FERC. The complaint alleges that we, as a seller with market-based rates, violated our tariffs by not filing with the FERC transaction-specific information about all of our sales and purchases at market-based rates. The California Attorney General argued that, as a result, all past sales should be subject to a refund if they are found to be above just and reasonable levels. In May 2002, the FERC issued an order that largely denied the complaint and required only that we file revised transaction reports regarding prior sales in California spot markets. In September 2002, the California Attorney General petitioned the United States Court of Appeals for the Ninth Circuit for review of the FERC orders. The California Attorney General's petition is under consideration by the court.

On April 15, 2002, the California Attorney General filed a lawsuit against us in San Francisco County Superior Court. The lawsuit is substantially similar to the complaint described above filed by the California Attorney General with the FERC. The lawsuit also alleges that we consistently charged unjust and unreasonable prices for electricity and that each unjust charge violated California law. The lawsuit seeks fines of up to $2,500 for each alleged violation and such other equitable relief as may be appropriate. We removed this lawsuit to the United States District Court for the Northern District of California. In March 2003, the court granted our motion to dismiss this lawsuit on the grounds that the plaintiffs' claims are barred by federal preemption and the FERC filed rate doctrine.

On April 15, 2002, the California Attorney General and the California Department of Water Resources filed a lawsuit against us in the United States District Court for the Northern District of California. The plaintiffs allege that our acquisition of electric generating facilities from Southern California Edison in 1998 violated

Section 7 of the Clayton Act, which prohibits mergers or acquisitions that substantially lessen competition. The lawsuit alleges that the acquisitions gave us market power, which we then exercised to overcharge California consumers for electricity. The lawsuit seeks injunctive relief against alleged unfair competition, divestiture of our California facilities, disgorgement of alleged illegal profits, damages, and civil penalties for each alleged exercise of illegal market power. In March 2003, the court dismissed the plaintiffs' claim for damages and Section 7 of the Clayton Act but declined to dismiss the plaintiffs' injunctive claim for divestiture of our California facilities.

California Lieutenant Governor Class Action. On November 20, 2002, the California Lieutenant Governor filed a taxpayer representative lawsuit against us in Superior Court of the State of California, Los Angeles County on behalf of purchasers of gas and power in California. The plaintiffs allege that we manipulated the pricing of gas and power by reporting false prices and fraudulent trades to the publishers of various price indices. The lawsuit seeks injunctive relief, disgorgement of profits and funds acquired by the alleged unlawful conduct.

FERC Complaints. On April 11, 2002, the FERC set for hearing a series of complaints filed by Nevada Power Company, which seek reformation of certain forward power contracts with several companies, including two contracts with us that have since been terminated. In December 2002, the presiding administrative law judge in these consolidated proceedings issued recommended findings of fact favorable to our positions and upholding the contracts. Those recommendations are pending before the FERC for final decision. PacifiCorp Company filed a similar complaint challenging two 90-day contracts with us. In February 2003, the presiding administrative law judge issued an initial decision recommending the dismissal of PacifiCorp Company's complaint and upholding the contracts. The FERC has stated that it intends to issue final decisions in both complaints in May 2003.

Trading and Marketing Proceedings and Investigations. We are party to the following proceedings and investigations relating to our trading and marketing activities, including our round trip trades and certain structured transactions.

In June 2002, the SEC advised us that it had issued a formal order in connection with its investigation of our financial reporting, internal controls and related matters. The investigation is focused on our round trip trades and certain structured transactions. We are cooperating with the SEC staff.

As part of the Commodity Futures Trading Commission's (CFTC) industry-wide investigation of so-called round trip trading, the CFTC has subpoenaed documents, requested information and conducted discovery relating to our natural gas and power trading activities, including round trip trades and alleged price manipulation, occurring since January 1999. The CFTC is also looking into the facts and circumstances surrounding certain events in June 2000 that were the subject of a settlement with FERC in January 2003 described below. We are cooperating with the CFTC staff.

On March 26, 2003, the FERC staff issued a report entitled "Final Report on Price Manipulation in Western Markets," which expanded and finalized the FERC staff's August 13, 2002 initial report. Certain findings, conclusions and observations in the FERC staff report, if adopted or otherwise acted on by the FERC, could have a material adverse affect on us. The report recommends the institution of proceedings directing certain entities, including us, to show cause why bids submitted in markets operated by the Cal ISO and California Power Exchange (Cal PX) from May to October 2000 did not constitute economic withholding or inflated bidding in violation of the Cal ISO and Cal PX tariffs. If adopted, such proceedings could require a disgorgement of revenues related to some sales for the period May to October 2000. The report also recommends the institution of proceedings directing certain entities, including us, to show cause why certain behavior identified in a January 6, 2003 report by the Cal ISO, entitled "Analysis of Trading and Scheduling Strategies Described in the Enron

Memos," did not constitute gaming in violation of the tariffs of the Cal ISO and Cal PX, and if adopted, such proceedings could require a disgorgement of revenues from certain transactions from the period January 1, 2000 through June 21, 2001, which the Cal ISO report identified as an amount less than $30.00 potentially attributable to us. We will have an opportunity to provide comments on these recommendations before formal proceedings are commenced. Finally, the report recommends that certain entities, including us, demonstrate that we no longer sell natural gas at wholesale or have instituted certain practices with regards to reporting natural gas price information, have disciplined employees that participated in manipulation or attempted manipulation of public price indices, and are cooperating fully with any government agency investigating our prior price reporting practices. We do not know when FERC intends to act on the staff's recommendations.

Also on March 26, 2003, the FERC instituted proceedings directing our trading company and BP Energy Company (BP) to show cause why each company's market-based rate authority should not be revoked. These proceedings arose in connection with certain actions taken by one of our traders and one of BP's traders relating to sales of electricity at the Palo Verde hub. If FERC were to prospectively revoke our trading company's market-based rate authority, it could have a material adverse affect on us. We must respond to the FERC within twenty-one days and intend to contest the FERC's proposed remedy for the alleged conduct.

On January 31, 2003, in connection with the FERC's investigation of potential manipulation of electricity and natural gas prices in the Western United States, the FERC approved a stipulation and consent agreement between the FERC staff and us relating to certain actions taken by some of our traders over a two-day period in June 2000. Under the agreement, we agreed to pay $14 million directly to customers of the Cal PX and certain other terms, including a requirement to abide by a must offer obligation to submit bids for all of our uncommitted, available capacity from our plants located in California into a California spot market one additional year following termination of our existing must offer obligation or until December 31, 2006, whichever is later.

We have received subpoenas and informal requests for information from the United States Attorney for the Southern District of New York and the Northern District of California for documents, interviews and other information pertaining to the round trip trades, and our energy trading activities. We are cooperating with both offices of the United States Attorney.

In connection with the PUCT's industry-wide investigation into potential manipulation of the ERCOT market, we have provided information to the PUCT concerning our scheduling and trading practices on and after July 31, 2001. Also, we, and four other qualified scheduling entities in ERCOT, reached a settlement relating to scheduling issues that arose during August 2001. The PUCT approved the settlement on November 7, 2002.

Shareholder Class Actions. We, as well as certain of our present and former officers and directors, have been named as defendants in 11 class action lawsuits filed on behalf of purchasers of our securities and the securities of CenterPoint. CenterPoint is also named as a defendant in three of the lawsuits. Two of the lawsuits name as defendants the underwriters of our IPO, which we have agreed to indemnify. One of those two lawsuits names our independent auditors as a defendant. The dates of filing of these lawsuits are as follows: two lawsuits on May 15, 2002; two lawsuits on May 16, 2002; one lawsuit on May 17, 2002; one lawsuit on May 20, 2002; one lawsuit on May 21, 2002; one lawsuit on May 23, 2002; one lawsuit on June 19, 2002; one lawsuit on June 20, 2002; and one lawsuit on July 1, 2002. Ten of the lawsuits were filed in the United States District Court, Southern District of Texas, Houston Division. One lawsuit was filed in the United States District Court, Eastern District of Texas, Texarkana Division and subsequently transferred to the United States District Court, Southern District of Texas, Houston Division. The lawsuits allege that the defendants overstated revenues by including

transactions involving the purchase and sale of commodities with the same counterparty at the same price and that we improperly accounted for certain other transactions. The lawsuits seek monetary damages and, in one of the lawsuits rescission, on behalf of a supposed class. In eight of the lawsuits, the class is composed of persons who purchased or otherwise acquired our securities and/or the securities of CenterPoint during specified class periods. The three lawsuits that include CenterPoint as a named defendant were also filed on behalf of purchasers of our securities and/or the securities of CenterPoint during specified class periods.

Four class action lawsuits were filed on behalf of purchasers of the securities of CenterPoint. CenterPoint and several of its officers are named as defendants. The dates of filing of the four lawsuits are as follows: one on May 16, 2002; one on May 21, 2002; one on June 13, 2002; and one on June 17, 2002. The lawsuits were filed in the United States District Court, Southern District of Texas, Houston Division. The lawsuits allege that the defendants violated federal securities laws by issuing false and misleading statements to the public. The plaintiffs allege that the defendants made false and misleading statements as part of an alleged scheme to artificially inflate trading volumes and revenues by including transactions involving the purchase and sale of commodities with the same counterparty at the same price, to use the spin-off to avoid exposure to our liabilities and to cause the price of our stock to rise artificially, among other things. The lawsuits seek monetary damages on behalf of persons who purchased CenterPoint securities during specified class periods. The court consolidated all of the lawsuits pending in the United States District Court, Southern District of Texas, Houston Division and appointed the Boca Raton Police & Firefighters Retirement System and the Louisiana School Employees Retirement System to be the lead plaintiffs in these lawsuits. The lead plaintiffs seek monetary relief purportedly on behalf of purchasers of CenterPoint common stock from February 3, 2000 to May 13, 2002, purchasers of our common stock in the open market from May 1, 2001 to May 13, 2002 and purchasers of our common stock in our IPO or purchasers of common stock that are traceable to our IPO. The lead plaintiffs allege, among other things, that the defendants misrepresented our revenues and trading volumes by engaging in round trip trades and improperly accounted for certain structured transactions as cash flow hedges, which resulted in earnings from these transactions being accounted for as future earnings rather than being accounted for as earnings in 2001.

On February 7, 2003, a lawsuit was filed against us in United States District Court for the Northern District of Illinois, Eastern Division. The plaintiffs allege that we violated federal securities law, Illinois common law and the Illinois Consumer Fraud and Deceptive Trade Practices Act. The lawsuit makes allegations similar to those made in the above-described class action lawsuits and seeks treble the amount of damages alleged, costs of suit and attorneys' fees.

ERISA Action. On May 30, 2002, a class action lawsuit was filed in the United States District Court, Southern District of Texas, Houston Division against us, certain of our present and former officers and directors, CenterPoint, certain of the present and former directors and officers of CenterPoint and certain present and former members of the benefits committee of CenterPoint on behalf of participants in various employee benefits plans sponsored by CenterPoint. The lawsuit alleges that the defendants breached their fiduciary duties to various employee benefits plans sponsored by CenterPoint, in violation of the Employee Retirement Income Security Act. The plaintiffs allege that the defendants permitted the plans to purchase or hold securities issued by CenterPoint when it was imprudent to do so, including after the prices for such securities became artificially inflated because of alleged securities fraud engaged in by the defendants. The lawsuit seeks monetary damages for losses suffered by a class of plan participants whose accounts held CenterPoint securities or our securities, as well as equitable relief in the form of restitution.

Shareholder Derivative Actions. On May 17, 2002, a derivative lawsuit was filed against our directors and independent auditors in the 269th Judicial District, Harris County, Texas. The lawsuit alleges that the defendants

breached their fiduciary duties to us. The shareholder plaintiff alleges that the defendants caused us to conduct our business in an imprudent and unlawful manner, including allegedly failing to implement and maintain an adequate internal accounting control system, engaging in transactions involving the purchase and sale of commodities with the same counterparty at the same price, and disseminating materially misleading and inaccurate information regarding our revenue and trading volume. The lawsuit seeks monetary damages on behalf of us.

On October 25, 2002, a derivative lawsuit was filed against the directors and officers of CenterPoint. The lawsuit was filed in the United States District Court for the Southern District of Texas, Houston Division. The lawsuit alleges breach of fiduciary duty, waste of corporate assets, abuse of control and gross mismanagement by the defendants causing CenterPoint to overstate the revenues through round trip and structured transactions and breach of fiduciary duty in connection with the Distribution and our IPO. The lawsuit seeks monetary damages on behalf of CenterPoint as well as equitable relief in the form of a constructive trust on the compensation paid to the defendants. A special litigation committee appointed by the board of directors of CenterPoint is investigating similar allegations made in a June 28, 2002 demand letter from a stockholder of CenterPoint. The letter states that certain shareholders of CenterPoint are considering filing a derivative suit on behalf of CenterPoint and demands that CenterPoint take several actions in response to the alleged round trip trades and structured transactions. The special litigation committee is investigating the allegations made in the demand letter to determine whether pursuit of a derivative lawsuit is in the best interest of CenterPoint.

Environmental Matters.

REMA Ash Disposal Site Closures and Site Contaminations. Under the agreement to acquire REMA (see note 5(b)), we became responsible for liabilities associated with ash disposal site closures and site contamination at the acquired facilities in Pennsylvania and New Jersey prior to a plant closing, except for the first $6 million of remediation costs at the Seward Generating Station. A prior owner retained liabilities associated with the disposal of hazardous substances to off-site locations prior to November 24, 1999. As of December 31, 2002, REMA had liabilities associated with six future ash disposal site closures and six current site investigations and environmental remediations. We have recorded our estimate of these environmental liabilities in the amount of $35 million as of December 31, 2002. We expect approximately $13 million will be paid over the next five years.

REPGB Asbestos Abatement and Environmental Remediation. Prior to our acquisition of REPGB (see note 5(c)), REPGB had a $25 million obligation primarily related to asbestos abatement, as required by Dutch law, and soil remediation at six sites. During 2000, we initiated a review of potential environmental matters associated with REPGB's properties. REPGB began remediation in 2000 of the properties identified to have exposed asbestos and soil contamination, as required by Dutch law and the terms of some leasehold agreements with municipalities in which the contaminated properties are located. As of December 31, 2002, the recorded undiscounted liability for asbestos abatement, soil remediation and plant water system compliance was $20 million. We expect approximately $8 million will be paid over the next five years.

Orion Power Environmental Contingencies. In connection with Orion Power's acquisition of 70 hydro plants in northern and central New York and four gas-fired or oil-fired plants in New York City, Orion Power assumed the liability for the estimated cost of environmental remediation at several properties. Orion Power developed remediation plans for each of these properties and entered into Consent Orders with the New York State Department of Environmental Conservation at two New York City sites and one hydro site for releases of petroleum and other substances by the prior owners. As of December 31, 2002, the undiscounted liability assumed and recorded by us for these assets was approximately $8 million, which we expect to pay out through 2006.

In connection with the acquisition of Midwest assets by Orion Power, Orion Power became responsible for the liability associated with the closure of three ash disposal sites in Pennsylvania. As of December 31, 2002, the liability assumed and recorded by us for these disposal sites was approximately $14 million, with $1 million to be paid over the next five years.

Other Matters.

We are involved in other legal and environmental proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. We believe that the effects on our consolidated financial statements, if any, from the disposition of these matters will not have a material adverse effect on our financial condition, results of operations or cash flows.

(i) California Energy Sales Credit and Refund Provisions.

During portions of 2000 and 2001, prices for wholesale electricity in California increased dramatically as a result of a combination of factors, including higher natural gas prices and emission allowance costs, reduction in available hydroelectric generation resources, increased demand, decreased net electric imports and limitations on supply as a result of maintenance and other outages. Although wholesale prices increased, California's deregulation legislation kept retail rates frozen at 10% below 1996 levels for two of California's public utilities, Pacific Gas and Electric (PG&E) and Southern California Edison Company (SCE), until rates were raised by the California Public Utilities Commission early in 2001. Due to the disparity between wholesale and retail rates, the credit ratings of PG&E and SCE fell below investment grade. Additionally, PG&E filed for protection under the bankruptcy laws in April 2001. As a result, PG&E and SCE are no longer considered creditworthy, and since January 17, 2001, have not directly purchased power from third-party suppliers through the Cal ISO to serve that portion of the power demand that cannot be met from their own supply sources (net short load). Pursuant to emergency legislation enacted by the California legislature, the California Department of Water Resources (CDWR) negotiated and purchased power through short and long-term contracts and through real-time markets operated by the Cal ISO to serve the net short load requirements of PG&E and SCE. In December 2001, the CDWR began making payments to the Cal ISO for real-time transactions. In May 2002, the FERC issued an order stating that wholesale suppliers, including us, should receive interest payments on past due amounts owed by the Cal ISO and the CDWR. As a result, we recorded $5 million of net interest receivable during 2002, discussed below. The CDWR has now made payment through the Cal ISO for its real-time energy deliveries subsequent to January 17, 2001, although the Cal ISO's distribution of the CDWR's payment for the month of January 2001, and the allocation of interest to past due amounts, are the subjects of motions that we have filed with the FERC objecting to the Cal ISO's failure to allocate the January payment and interest solely to post January 17, 2001 transactions. In addition, we are prosecuting a lawsuit in California to recover the market value of forward contracts seized by California Governor Gray Davis in violation of the Federal Power Act. Governor Davis' actions prevented the liquidation of the contracts by the Cal PX to satisfy the outstanding obligations of SCE and PG&E to wholesale suppliers, including us. The timing and ultimate resolution of this claim is uncertain at this time.

California Credit Provision. We were owed a total receivable, including interest, of $302 million (net of estimated refund provision of $15 million) as of December 31, 2001, and $120 million (net of estimated refund provision of $191 million) as of December 31, 2002, by the Cal ISO, the Cal PX, the CDWR, and California Energy Resources Scheduling for energy sales in the California wholesale market during the fourth quarter of 2000 through December 31, 2002. From January 1, 2003 through March 31, 2003, we have collected $7 million of these receivable balances.

During 2000 and 2001, we recorded net pre-tax credit provisions against receivable balances related to energy sales in California of $39 million and $29 million, respectively. As of December 31, 2001, we had a pre-tax credit provision of $68 million against receivable balances related to energy sales in the California market. During 2002, $62 million of a previously accrued credit provision for energy sales in California was reversed. The reversal resulted from collections of outstanding receivables during the period, a determination that credit risk had been reduced on the remaining outstanding receivables as a result of payments in 2002 to the Cal PX and due to the write-off of receivables as a result of a May 15, 2002 FERC order and related interpretations and a March 26, 2003 FERC order on proposed findings on refund liability, discussed below. As of December 31, 2002, we had a remaining pre-tax credit provision of $6 million against these receivable balances. We will continue to assess the collectability of these receivables based on further developments.

FERC Refunds. In response to the filing of a number of complaints challenging the level of wholesale prices in California, the FERC initiated a staff investigation and issued a number of orders implementing a series of wholesale market reforms. In these orders, the FERC also instituted a refund proceedings, described below. Prior to proposing a methodology for calculating refunds in the refund proceeding discussed below, the FERC identified amounts charged by us for sales in California to the Cal ISO and the Cal PX for the period January 1, 2001 through June 19, 2001 as being subject to possible refunds. Accordingly, during 2001, we accrued refunds of $15 million.

The FERC issued an order in July 2001 adopting a refund methodology and initiating a hearing schedule to determine (a) revised mitigated prices for each hour from October 2, 2000 through June 20, 2001, (b) the amount owed in refunds by each electric wholesale supplier according to the methodology and (c) the amount currently owed to each electric wholesale supplier. The FERC issued an order on March 26, 2003, adopting in most respects the proposed findings of the presiding administrative law judge that had been issued in December 2002 following a hearing to apply the refund formula. The most consequential change involved the adoption of a different methodology for determining the gas price component of the refund formula. Instead of using California gas indices, the FERC ordered the use of a proxy gas price based on producing area price indices plus the posted transportation costs. In addition, the order allows generators to petition for a reduction of the refund calculation upon a submittal to the FERC of their actual gas costs and subsequent FERC approval. Based on the proposed findings of the administrative law judge, discussed above, adjusted for the March 2003 FERC decision to revise the methodology for determining the gas price component of the formula, we estimate our refund obligation to be between $191 million and $240 million for energy sales in California (excluding the $14 million refund related to the FERC settlement in January 2003, as discussed in note 14(h)). The low range of our estimate is based on a refund calculation factoring in a reduction in the total FERC refund based on the actual cost paid for gas over the proposed proxy gas price. Our estimate of the range will be revised further as all components of the FERC order can be analyzed. We cannot currently predict whether that will result in an increase or decrease in our high and low points in the range. The high range of our estimate of the refund obligation assumes that the refund obligation is not adjusted for the actual cost paid for gas over the proposed proxy gas price. During 2002, we recorded reserves for refunds of $176 million related to energy sales in California. As discussed above, $15 million was recognized during 2001. As of December 31, 2002, our reserve for refunds related to energy sales in California is $191 million, excluding the $14 million related to the FERC settlement in January 2003, see note 14(h). The California refunds, excluding the $14 million related to the FERC settlement discussed in note 14(h), will likely be offset against unpaid amounts owed to us for our prior sales in California.

Interest Calculation. In the fourth quarter of 2002, we recorded net interest income of $5 million based on the December 2002 findings of the presiding administrative law judge. The net interest income was estimated

using the low end of the potential refund, the receivable balance outstanding, and the quarterly interest rates for the applicable time period designated by the FERC.

(j) European Stranded Cost and Indemnification and Settlement of Stranded Cost.

Background. In January 2001, the Dutch Electricity Production Sector Transitional Arrangements Act (Transition Act) became effective. Among other things, the Transition Act allocated to REPGB and the three other large-scale Dutch generation companies, a share of the assets, liabilities and stranded cost commitments of NEA. Prior to the enactment of the Transition Act, NEA acted as the national electricity pooling and coordinating body for the generation output of REPGB and the three other large-scale national Dutch generation companies. REPGB and the three other large-scale Dutch generation companies are shareholders of NEA.

The Transition Act and related agreements specify that REPGB has a 22.5% share of NEA's assets, liabilities and stranded cost commitments. NEA's stranded cost commitments consisted primarily of various uneconomical or stranded cost investments and commitments, including three gas supply contracts and four power contracts, entered into prior to the liberalization of the Dutch wholesale electricity market and a contract relating to the construction of an interconnection cable between Norway and the Netherlands subject to a long-term power exchange agreement (the NorNed Project). REPGB's stranded cost obligations also includes uneconomical district heating contracts that were previously administrated by NEA prior to deregulation of the Dutch power market.

In January 2001, we recognized an out-of-market, net stranded cost liability for our gas and electric import contracts and district heating commitments. At such time, we recorded a corresponding asset of equal amount for the indemnification of this obligation from REPGB's former shareholders and the Dutch government, as applicable (as further discussed below).

The gas supply contract expires in 2016 and provides for gas imports aggregating 2.283 billion cubic meters, per year. In 2001, two of the stranded cost power contracts were settled and terminated. In May 2002, the two remaining stranded cost power contracts were amended. The district heating obligations relate to three water heating supply contacts entered into with various municipalities expiring from 2008 through 2015. Under the district heating contracts, the municipal districts are required to take annually a combined minimum of 5,549 terajoules (TJ) increasing annually to 7,955 TJ over the life of the contracts.

Stranded Cost Indemnification. Until December 2001, the former shareholders of REPGB were obligated to indemnify REPGB for up to NLG 1.9 billion (approximately $766 million as of December 31, 2001) of its share of NEA's stranded cost liabilities and the district heat stranded cost liabilities.

The Transition Act provided that, subject to the approval of the European Commission, the Dutch government will provide financial compensation to the Dutch generation companies, including REPGB, for liabilities associated with long-term district heating contracts. In July 2001, the European Commission ruled that under certain conditions the Dutch government can provide financial compensation for the district heating contracts. To the extent that this compensation is not ultimately provided to the generation companies by the Dutch government, REPGB is entitled to claim compensation directly from the former shareholders of REPGB as further discussed below.

Settlement of Stranded Cost Indemnification Agreement. In December 2001, REPGB and its former shareholders agreed to settle the indemnity obligations of the former shareholders insofar as they related to

NEA's stranded cost gas supply and power contracts and other obligations (excluding district heating obligations).

Under the settlement agreement, the former shareholders of REPGB paid REPGB NLG 500 million ($202 million) in the first quarter of 2002. REPGB deposited the settlement payment into an escrow account, withdrawals from which are at the discretion of REPGB for use in discharging stranded cost obligations related to the gas and electric import contracts. As of December 31, 2002, the remaining escrow funds of $6 million are recorded in restricted cash. Any remaining funds as of January 1, 2004 will be distributed to REPGB.

Prior to the settlement agreement, pursuant to the purchase agreement of REPGB, as amended, REPGB was entitled to an approximately $51 million dividend from NEA with any remainder owing to the former shareholders. Under the settlement agreement, the former shareholders waived all rights to distributions of NEA.

As a result of this settlement, we recognized in the fourth quarter of 2001 a net gain of $37 million for the difference between (a) the sum of the cash settlement payment of $202 million and the additional rights to claim distributions of the NEA investment of $248 million and (b) the sum of the amount recorded as stranded cost indemnity receivable related to the stranded cost gas and electric commitments of $369 million and claims receivable related to stranded cost incurred in 2001 of $44 million, both previously recorded in our consolidated balance sheet.

In addition, under the settlement agreement, the former shareholders continue to be under an obligation to indemnify REPGB for certain district heating contracts. Under the terms of the settlement agreement, REPGB can elect between two forms of indemnification after the Ministry of Economic Affairs of the Netherlands publishes its regulations for compensation of stranded cost associated with district heating projects. If the compensation to be paid by the Netherlands under these rules is at least as much as the compensation to be paid under the original indemnification agreement, REPGB can elect to receive a one-time payment of approximately $28 million (assuming the December 31, 2002 exchange rate of 1.0492 U.S. dollar per Euro) and in certain circumstances this payment can increase to approximately $36 million. If the compensation rules do not provide for compensation at least equal to that provided under the original indemnification agreement, REPGB can claim indemnification for stranded cost losses up to a maximum of approximately $333 million (assuming the December 31, 2002 exchange rate of 1.0492 U.S. dollar per Euro) less the amount of compensation provided by the new compensation rules and certain proceeds received from arbitrations. To date, the Ministry of Economic Affairs had not published its compensation rules. Based on current assumptions, it is anticipated that such rules will be published in 2003. If no compensation rules have taken effect by December 31, 2003, REPGB is entitled, but not obligated, to elect to seek compensation from the former shareholders, and as an alternative, is also entitled to wait to make an election until regulations for compensation are published.

Amendments to Stranded Cost Electricity Import Contracts. In May 2002, NEA and its four shareholders (including REPGB) entered into agreements amending the terms of the two remaining power supply agreements. These two contracts provide for the following capacities and terms: (a) 300 MW through 2003, and (b) 600 MW through March 2002, increasing to 750 MW through March 2009.

Under the terms of the settlement agreements, NEA paid the counterparties a net aggregate payment of Euro 485 million, approximately $446 million (of which REPGB's proportionate share as a NEA shareholder was Euro 109 million, approximately $100 million). In July 2002, REPGB paid its share of the settlement payment with funds from the stranded cost indemnity escrow account, as discussed above. In exchange for its portion of the settlement payment, the counterparties to the power contracts replaced the existing terms with a market-based electricity price index for comparable electricity products in addition to other changes.

As a result of the settlement agreements, in the second quarter of 2002, we recognized a pre-tax net gain of $109 million for the difference between (a) the fair values of the original power contracts ($203 million net liability previously recorded in non-trading derivative liabilities) and the fair values of the amended power contracts ($6 million net asset recorded in trading and marketing assets) and (b) the settlement payment of $100 million, as described above. The pre-tax net gain of $109 million was recorded as a reduction of purchased power expense in the statement of consolidated operations in the second quarter of 2002.

Remaining Liability for Original Stranded Cost. As of December 31, 2001, we have recorded a liability of $369 million for our stranded cost gas and electric commitments in non-trading derivative liabilities and a liability of $206 million for our district heating commitments in current and non-current other liabilities. As of December 31, 2002, we have recorded a liability of $154 million for our stranded cost gas contract in non-trading derivative liabilities, an asset of $8 million for our amended power contracts in trading and marketing assets, and a liability of $224 million for our district heating commitments in current and non-current other liabilities. As of December 31, 2001 and 2002, we have recorded an indemnification receivable for the district heating stranded cost liability of $206 million and $224 million, respectively.

Pursuant to SFAS No. 133, we mark-to-market the stranded cost gas contract. Prior to the amendments to the remaining two power contacts, pursuant to SFAS No. 133, the power contracts were marked-to-market. Subsequent to amending the remaining power contracts, the power contracts are marked-to-market as a part of our energy trading activities. Pursuant to SFAS No. 133, during 2002, we recognized a $19 million net gain recorded in fuel expense related to changes in the valuation of the stranded cost contracts, excluding the effects of the gain related to amending the two power contracts discussed above and net of derivative transactions entered into to hedge the economics of the stranded cost gas contract. The valuation of the gas contract could be affected by, among other things, changes in the price of coal, low sulfur fuel oil and the value of the U.S. dollar relative to the Euro.

NorNed Project. NEA entered into commitments with certain Norwegian counterparties (the Norwegian Counterparties) for the construction of a grid interconnector cable between the Netherlands and Norway, subject to the operation of a long-term power exchange agreement (25 years in duration). The power exchange agreement contemplates, among other terms, exclusive use and cost free access to the cable by NEA and the Norwegian counterparties. The power exchange agreement is subject to, among other things, clearance by the European Commission and the Dutch regulatory authorities of the terms and conditions of the power exchange agreement. In 2001, NEA and the Norwegian counterparties filed a notification request regarding the power exchange agreement with the European Commission. If the European Commission or the Dutch regulatory authorities do not unconditionally clear the terms and conditions of the cable construction agreement or the power exchange agreement, NEA and the Norwegian counterparties contractually will initiate a formal renegotiation period. If the parties cannot agree within the formal renegotiation period, the cable and power exchange agreement obligations are terminated. Under the Transition Act, NEA is entitled to recover the cable construction costs from TenneT, the Netherlands grid operator. However, at this early stage it is uncertain how NEA will receive the transport tariff funds intended to recover the construction costs of the cable. Assuming that the Transition Act is fully implemented with respect to this matter, REPGB believes that NEA will ultimately recover the cost of the cable.

Investment in NEA. During the second quarter of 2001, we recognized a $51 million pre-tax gain (NLG 125 million) recorded as equity income for the preacquisition gain contingency related to the acquisition of REPGB for the value of its equity investment in NEA. This gain was based on our evaluation of NEA's financial position and fair value. The fair value of our investment in NEA is dependent upon the ultimate resolution of its

existing contingencies and proceeds received from liquidating its remaining net assets. In addition, during 2001 in connection with the settlement of the stranded cost indemnity, we recorded a $248 million increase in our investment in NEA, as discussed above. In 2002, NEA distributed to REPGB Euro 141 million, approximately $137 million. For additional information regarding our investment in NEA, see note 8.

(k) Reliant Energy Desert Basin Contingency.

One of our subsidiaries, Reliant Energy Desert Basin (REDB), sells power to Salt River Project (SRP) under a long-term power purchase agreement. Reliant Resources guarantees certain of REDB's obligations under the agreement. In the event we are downgraded to below investment grade by two major ratings agencies, SRP can request performance assurance in the form of cash or a letter of credit from REDB under the agreement or us under the guarantee. The total amount of performance assurance cannot exceed $150 million. In September 2002, following our downgrade to below investment grade by two rating agencies, SRP requested performance assurance from us and REDB in the aggregate amount of $150 million. We informed SRP that the agreement does not stipulate the amount of performance assurance required in the event of a credit downgrade. We also communicated to SRP that under prevailing market conditions and after giving effect to other factors, a letter of credit in the amount of $3 million would provide commercially reasonable assurance of REDB's ability to perform its obligations under the agreement. Accordingly, we provided SRP with a $3 million letter of credit. SRP subsequently notified us that it deemed the amount inadequate and returned the letter of credit to us. SRP has alleged that we breached the agreement by failing to provide the requested $150 million letter of credit. We have communicated to SRP that we remain of the opinion that the provision of a $3 million letter of credit fulfills the obligation of us and REDB to provide performance assurance and that SRP would be in breach of the agreement and liable to REDB for damages if it were to terminate the agreement based on our refusal to provide performance assurance in the amount of $150 million. As of March 20, 2003, neither SRP nor we have taken steps to terminate the agreement.

(l) Tolling Agreement for Liberty's Electric Generating Station.

The output of Liberty's electric generating station is contracted under a tolling agreement between LEP and PG&E Energy Trading-Power, L.P. (PGET) for an initial term through September 2016, with an option by PGET to extend the initial term for an additional two years. Under the tolling agreement, PGET has the exclusive right to receive all electric energy, capacity and ancillary services produced by the Liberty generating station, and PGET must pay for all fuel used by the Liberty generating station.

The tolling agreement requires PGET to maintain guarantees, issued by entities having investment grade credit ratings, for its obligations under the tolling agreement. During 2002, several rating agencies downgraded to sub-investment grade the debt of the two guarantors of PGET, PG&E National Energy Group, Inc. and PG&E Gas Transmission Northwest Corp. Due to the fact that PGET did not post replacement security within the period required under the tolling agreement, the downgrade constitutes an event of default by PGET under the tolling agreement. The Liberty credit facility restricts the ability of LEP to terminate the tolling agreement. There is also a requirement in the Liberty credit facility that Liberty and LEP enforce all of their respective rights under the tolling agreement. Liberty and LEP have received a waiver from the lenders under the Liberty credit facility from the requirement that they enforce all of their respective rights under the tolling agreement. In return for this waiver, Liberty and LEP have agreed that for the term of the waiver, they would not be able to make draws on the working capital facility that is available under the Liberty credit facility. The current waiver expires on April 30, 2003. There is no assurance that Liberty and LEP will be able to receive an extension of this waiver. If Liberty is unable to obtain an extension to the waiver, then the lenders may claim that Liberty is in breach and, if said breach is not cured, that there is an event of default under the Liberty credit facility.

In addition, on August 19, 2002, and September 10, 2002, PGET notified LEP that it believed LEP had violated the tolling agreement by not following PGET's instructions relating to the dispatch of the Liberty station during specified periods. The September 10, 2002 letter also claims that LEP did not timely provide PGET with certain information to make a necessary FERC filing. While LEP does not agree with PGET's interpretation of the tolling agreement regarding the dispatch issue, LEP agreed to (a) compensate PGET approximately $17,000 for the alleged damages attributable to the claims raised in the August 19, 2002 letter and (b) treat several hours of plant outages as forced outages for purposes of the tolling agreement, thereby resolving the issues raised in the August 19 letter (which compensation and treatment are not believed to be material). The tolling agreement generally provides that covenant-related defaults must be cured within 30 business days or they will (if material) result in an event of default, entitling the non-defaulting party to terminate. PGET has extended this cure period (relating to the September 10, 2002 letter) to April 11, 2003. LEP has made the necessary FERC filing and is in negotiations with PGET regarding financial settlement for this issue for approximately $1 million. Further, LEP also believes that it has settled the monetary impact of any violation relating to the dispatch issue. While there can be no assurances as to the outcome of this matter, LEP believes that it will be able to resolve the issues raised in the September 10, 2002 letter without causing an event of default under the tolling agreement. However, if LEP is unable to resolve the issues and PGET declares an event of default, then PGET would be in a position to terminate the tolling agreement. In addition to the material adverse effect such a termination would have on Liberty as discussed below, such a termination may also result in PGET drawing on the $35 million letter of credit posted by Reliant Resources on behalf of LEP under the tolling agreement.

LEP currently receives a fixed monthly payment from PGET under the tolling agreement. If the tolling agreement is terminated, (a) LEP would need to find a power purchaser or tolling customer to replace PGET or sell the energy and/or capacity in the merchant energy market and (b) the gas transportation agreement that PGET utilizes in connection with the tolling agreement will revert to LEP, and LEP will be required to perform the obligations currently being performed by PGET under the gas transportation agreement, including the posting of $5 million in credit support.

No assurance can be given that LEP would have sufficient cash flow to pay all of its expenses or enable Liberty to make interest and scheduled principal payments under the Liberty credit facility as they become due if the tolling agreement is terminated. The termination of the tolling agreement may cause both Liberty and LEP to seek other alternatives, including reorganization under the bankruptcy laws. We, including Orion Power, would not be in default under our current debt agreements if any of these events occur at Liberty.

As of December 31, 2002, the combined net book value of LEP and Liberty was $425 million, excluding the non-recourse debt obligations of $268 million.

In December 2002, we evaluated the Liberty station and the related tolling agreement for impairment. Based on our analyses, there were no impairments. The fair value of Liberty station was determined based on an income approach, using future discounted cash flows; a market approach, using acquisition multiples, including price per MW, based on publicly available data for recently completed transactions; and a replacement cost approach. If the tolling agreement is terminated and there is not a waiver from the lenders for this event of default, it is possible the lender would initiate foreclosure proceedings against LEP and Liberty. If the lenders foreclose on LEP and Liberty, we believe we could incur a pre-tax loss of an amount up to our recorded net book value with the potential of an additional loss due to an impairment of goodwill allocated to LEP as a result of the foreclosure. Under the tolling agreement, a non-defaulting party who terminates the tolling agreement is entitled to calculate its damages in accordance with specified criteria; the non-defaulting party is the only party entitled to damages. The defaulting party would be entitled to refer such damage calculation to arbitration. The institution of

any arbitration could delay the receipt of such damages for an extended period of time. In addition, if PGET is the defaulting party, the payment of damages, if any, could be further delayed if PGET and one or more of the guarantors of PGET's obligations seeks protection from creditors under the bankruptcy laws. Such filings also may result in LEP receiving significantly less in damages than to which it might otherwise be entitled. In the event of a termination, if PGET is the defaulting party and LEP is entitled to the payment of damages as a result of the termination, any amounts recovered from PGET would be handled in accordance with the Liberty credit facility. The most likely result is that the damages would be paid into an account that is managed by the lenders under the credit facility and LEP would not recover any of such damages.

(15) RECEIVABLES FACILITY

In July 2002, we entered into a receivables facility arrangement with a financial institution to sell an undivided interest in our accounts receivable and accrued unbilled revenues from residential and small commercial retail electric customers under which, on an ongoing basis, the financial institution could invest a maximum of $250 million for its interest in such receivables. In November 2002, the maximum amount of the receivables facility was reduced to $200 million. In February 2003, this was further reduced to $125 million (see below). This receivables facility expires July 2003 and may be renewed at our option and the option of the financial institution participating in the facility. If the receivables facility is not renewed on its termination date, the collections from the receivables purchased will repay the financial institution's investment and no new receivables will be purchased under the receivables facility. There can be no assurance that the financial institution participating in the receivables facility will agree to a renewal. The receivables facility may be increased to an amount greater than $200 million on a seasonal basis, subject to the availability of receivables and approval by the participating financial institution.

We received net proceeds in an initial amount of $230 million at the inception of this receivables facility. The amount of funding available to us under the receivables facility will fluctuate based on the amount of receivables available, which in turn, is effected by seasonal changes in demand for electricity and by the performance of the receivables portfolio. As of December 31, 2002, the amount of funding outstanding under our receivables facility was $95 million.

Pursuant to the receivables facility, we formed a qualified special purpose entity (QSPE), as a bankruptcy remote subsidiary. The QSPE was formed for the sole purpose of buying and selling receivables generated by us. The QSPE is a separate entity and its assets will be available first and foremost to satisfy the claims of its creditors. We, irrevocably and without recourse, transfer receivables to the QSPE. We continue to service the receivables and receive a fee of 0.5% of cash collected. We received total fees of $8 million for the year ended December 31, 2002. We have no servicing assets or liabilities, because servicing fees are based on actual costs associated with collection of accounts receivable. The QSPE, in turn, sells an undivided interest in these receivables to the participating financial institution. We are not ultimately liable for any failure of payment of the obligors on the receivables. We have, however, guaranteed the performance obligations of the sellers and the servicing of the receivables under the related documents.

The two-step transaction described in the above paragraph is accounted for as a sale of receivables under the provisions of SFAS No. 140 "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and as a result the related receivables are excluded from the consolidated balance sheet. Costs associated with the sale of receivables, $10 million for the year ended December 31, 2002, primarily the discount and loss on sale, is included in other expense in our statement of consolidated operations. As of December 31, 2002, $277 million of the outstanding receivables had been sold and the sales have been reflected as a reduction

of accounts receivable in our consolidated balance sheet. We have a note receivable from the QSPE of approximately $170 million at December 31, 2002, which is included in the consolidated balance sheet. This note is calculated as the amount of receivables sold to the QSPE, less the interest in the receivables sold by the QSPE to the financial institution, and the equity investment in the QSPE, which is equal to 3% of the receivables balance. At December 31, 2002, the equity investment balance was $8 million.

The book value of the accounts receivable is offset by the amount of the allowance for doubtful accounts and customer security deposits. A discount rate of 5.40% was applied to projected cash collections over a 6-month period. Our collection experience indicated that 98% of the accounts receivables would be collected within a 6-month period.

On December 2, 2002, we notified the financial institution under the receivables facility of two violations of certain compliance ratio tests that are considered amortization events whereby the financial institution has the right to liquidate the receivables it owns to collect the total amount outstanding under the terms of the receivables facility. On February 7, 2003, we were granted an amendment to our receivables facility and a waiver of these two compliance ratio violations from the financial institution. As part of the amendment and waiver, the size of the receivables facility was reduced from $200 million to $125 million.

In addition, an amortization event was added that requires us to attain by February 17, 2003 either: (a) a consensual refinancing of certain credit facilities or (b) another financing commitment. We received waivers of this amortization event until March 31, 2003, at which time we refinanced certain credit facilities, see note 21(a).

(16) RELIANT ENERGY COMMUNICATIONS

During the third quarter of 2001, management decided to exit our communications business that served as a facility-based competitive local exchange carrier and Internet services provider and owned network operations centers and managed data centers in Houston and Austin. Consequently, we determined the goodwill associated with the communications business was impaired. We recorded a total of $54 million of pre-tax disposal charges in the third and fourth quarters of 2001. These charges included the write-off of goodwill of $19 million, fixed asset impairments of $22 million, and severance accruals and other incremental costs associated with exiting the communications business, totaling $13 million.

(17) BANKRUPTCY OF ENRON CORP AND ITS AFFILIATES

During the fourth quarter of 2001, Enron filed a voluntary petition for bankruptcy. Accordingly, we recorded an $85 million provision, comprised of provisions against 100% of receivables of $88 million and net non-trading derivative balances of $52 million, offset by our net trading and marketing liabilities to Enron of $55 million.

The non-trading derivatives with Enron were designated as cash flow hedges (see note 7). The unrealized net gain on these derivative instruments previously reported in other comprehensive income will remain in accumulated other comprehensive loss and will be reclassified into earnings during the period in which the originally designated hedged transactions occur. During 2002, $52 million was reclassified into earnings related to these cash flow hedges.

In early 2002, we commenced an action in the United States District Court to recover from Enron Canada Corp., the only Enron party to our netting agreement which is not in bankruptcy, the settlement amount of $78

million, which resulted from netting amounts owed by and among the five Enron parties and our applicable subsidiaries. In March 2002, the United States District Court dismissed our claim and we appealed the decision to the United States Court of Appeals for the Fifth Circuit (the Fifth Circuit). Oral arguments were heard in March 2003.

At this time we cannot predict whether our appeal will be successful. The United States District Court, however, did determine that netting of amounts owed by and among our parties and the Enron parties was proper. This portion of the United States District Court's ruling has not been appealed. In other proceedings initiated by Enron in the Bankruptcy Court for the Southern District of New York, Enron is alleging that netting agreements, such as the one it signed with us, are unenforceable. This contention is not currently at issue in our appeal pending in the Fifth Circuit. We cannot currently predict whether Enron will contest the enforceability of its netting agreement with us, nor the outcome of such dispute. In January 2003, Enron filed a complaint in the Bankruptcy Court of Southern District New York claiming that it is owed $13 million from us and disputing the enforceability of our netting agreement. Our answer to the filed complaint is due in April 2003. We believe our netting agreement with the Enron entities is enforceable as found by the United States District Court, and will continue to defend such opinion.

(18) ESTIMATED FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair values of financial instruments, including cash and cash equivalents, certain short-term and long-term borrowings (excluding any fixed-rate debt and other borrowings as discussed below), trading and marketing assets and liabilities (see note 7), and non-trading derivative assets and liabilities (see note 7), are equivalent to their carrying amounts in the consolidated balance sheets. The fair values of trading and marketing assets and liabilities and non-trading derivative assets and liabilities as of December 31, 2001 and 2002 have been determined using quoted market prices for the same or similar instruments when available or other estimation techniques, see note 7.

As of December 31, 2001, the carrying value of our fixed-rate debt of $121 million equaled the market value. The carrying value and related market value of our fixed-rate debt, excluding Liberty's fixed-rate debt of $165 million, was $637 million and $448 million, respectively, as of December 31, 2002. The market value of our fixed-rate debt is based on our incremental borrowing rates for similar types of borrowing arrangements. There was no active market for the fixed-rate Liberty debt of $165 million as of December 31, 2002. Due to our current situation with Liberty (see note 14(l)), if the holder of our fixed-rate debt of $165 million were to have tried to sell such debt instrument to a third party, the price which could have been realized could be substantially less than the face value of the debt instrument and substantially less than our carrying value as of December 31, 2002.

As of December 31, 2002, we have floating-rate debt with a carrying value of $6.7 billion. There was no active market for our floating-rate debt obligations as of December 31, 2002. Given our current liquidity and credit situation as of December 31, 2002, if the holders of these borrowings were to have tried to sell such debt instruments to third parties, the prices which could have been realized could be substantially less than the face values of the debt instruments and substantially less than our carrying values.

(19) RESTATED UNAUDITED QUARTERLY INFORMATION

Beginning with the quarter ended September 30, 2002, we now report all energy trading and marketing activities on a net basis in the statements of consolidated operations. For information regarding the presentation

of trading and marketing activities on a net basis, see notes 2(t) and 7. The effect of the change to reporting on a net basis on previously reported quarterly information is discussed in note 1 to the table below. Accordingly, the unaudited quarterly information for the interim periods for 2001 and the interim periods ended March 31, 2002 and June 30, 2002 have been reclassified to conform to this presentation. During the third quarter of 2002, we completed the transitional impairment test for the adoption of SFAS No. 142 on our consolidated financial statements, including the review of goodwill for impairment as of January 1, 2002 (see note 6). Based on this impairment test, we recorded an impairment of our European energy segment's goodwill of $234 million, net of tax. This impairment loss was recorded retroactively as a cumulative effect of a change in accounting principle for the quarter ended March 31, 2002.

In addition, as discussed in note 1, the consolidated financial statements for 2001 have been restated from amounts previously reported and we miscalculated the amount of hedge ineffectiveness for the first three quarters of 2002 for hedging instruments entered into prior to the adoption SFAS No. 133. In addition, we did not record the amount of ineffectiveness for any hedging instruments during the first three quarters of 2001. As a result, the unaudited quarterly information for each of the quarters in 2001 and the first three quarters of 2002 have been restated from amounts previously reported. The restatement had no impact on previously reported consolidated operating, investing and financing cash flows for 2001 or 2002. The following is a summary of the principal effects of the restatement for unaudited quarterly information for the quarters ended March 31, 2001 and 2002, June 30, 2001 and 2002, September 30, 2001 and 2002, and December 31, 2001: (Note—Those line items for which no change in amounts are shown were not affected by the restatement.)

	Year Ended December 31, 2001			
	First Quarter		Second Quarter	
	As Restated	As Previously Reported(1)	As Restated	As Previously Reported(1)
	(in millions)			
Revenues	$1,393	$1,410	$1,526	$1,545
Trading margins	119	119	131	131
Total revenues	1,512	1,529	1,657	1,676
Operating income	97	114	275	294
Income before income taxes and cumulative effect of accounting change	93	110	329	348
Income tax expense	25	31	113	120
Income before cumulative effect of accounting change	68	79	216	228
Net income	71	82	216	228
Basic Earnings Per Share:				
Income before cumulative effect of accounting change	$ 0.28	$ 0.33	$ 0.78	$ 0.83
Cumulative effect of accounting change, net of tax	0.01	0.01	—	—
Net income	$ 0.29	$ 0.34	$ 0.78	$ 0.83
Diluted Earnings Per Share:				
Income before cumulative effect of accounting change	$ 0.28	$ 0.33	$ 0.78	$ 0.82
Cumulative effect of accounting change, net of tax	0.01	0.01	—	—
Net income	$ 0.29	$ 0.34	$ 0.78	$ 0.82

	Year Ended December 31, 2001			
	Third Quarter		Fourth Quarter	
	As Restated	As Previously Reported(1)	As Restated	As Previously Reported(1)
	(in millions)			
Revenues	$2,473	$2,400	$ 738	$ 767
Trading margins	62	62	57	57
Total revenues	2,535	2,462	795	824
Operating income (loss)	425	352	(27)	2
Income (loss) before income taxes and cumulative effect of accounting change	437	364	(25)	4
Income tax expense (benefit)	175	150	(39)	(29)
Income before cumulative effect of accounting change	262	214	14	33
Net income	262	214	14	33
Basic Earnings Per Share:				
Income before cumulative effect of accounting change	$ 0.87	$ 0.71	$0.05	$0.11
Cumulative effect of accounting change, net of tax	—	—	—	—
Net income	$ 0.87	$ 0.71	$0.05	$0.11
Diluted Earnings Per Share:				
Income before cumulative effect of accounting change	$ 0.87	$ 0.71	$0.05	$0.11
Cumulative effect of accounting change, net of tax	—	—	—	—
Net income	$ 0.87	$ 0.71	$0.05	$0.11

	Year Ended December 31, 2002			
	First Quarter		Second Quarter	
	As Restated	As Previously Reported(1)	As Restated	As Previously Reported(1)
	(in millions)			
Revenues	$1,754	$1,755	$2,226	$2,230
Trading margins	53	53	119	119
Total revenues	1,807	1,808	2,345	2,349
General, administrative and development	113	113	167	167
Operating income	165	166	329	333
Income before income taxes and cumulative effect of accounting change	138	139	279	283
Income tax expense	42	42	104	105
Income before cumulative effect of accounting change	96	97	175	178
Net (loss) income	(138)	(137)	175	178
Basic Earnings (Loss) Per Share:				
Income before cumulative effect of accounting change	$ 0.33	$ 0.34	$ 0.61	$ 0.62
Cumulative effect of accounting change, net of tax	(0.81)	(0.81)	—	—
Net (loss) income	$(0.48)	$(0.47)	$ 0.61	$ 0.62
Diluted Earnings (Loss) Per Share:				
Income before cumulative effect of accounting change	$ 0.33	$ 0.34	$ 0.60	$ 0.61
Cumulative effect of accounting change, net of tax	(0.81)	(0.81)	—	—
Net (loss) income	$(0.48)	$(0.47)	$ 0.60	$ 0.61

	Year Ended December 31, 2002		
	Third Quarter		
	As Restated	As Previously Reported	Fourth Quarter
Revenues	$5,225	$5,236	$2,043
Trading margins	119	119	19
Total revenues	5,344	5,355	2,062
General, administrative and development	224	224	161
Operating income (loss)	271	282	(645)
Income (loss) before income taxes and cumulative effect of accounting change	189	200	(718)
Income tax expense (benefit)	138	142	(70)
Income (loss) before cumulative effect of accounting change	51	58	(648)
Net income (loss)	51	58	(648)
Basic Earnings (Loss) Per Share:			
Income (loss) before cumulative effect of accounting change	$ 0.17	$ 0.20	$ (2.23)
Cumulative effect of accounting change, net of tax	—	—	—
Net income (loss)	$ 0.17	$ 0.20	$ (2.23)
Diluted Earnings (Loss) Per Share:			
Income (loss) before cumulative effect of accounting change	$ 0.17	$ 0.20	$ (2.23)
Cumulative effect of accounting change, net of tax	—	—	—
Net income (loss)	$ 0.17	$ 0.20	$ (2.23)

(1) Beginning with the quarter ended September 30, 2002, we now report all energy trading and marketing activities on a net basis as allowed by EITF No. 98-10. Comparative financial statements for prior periods have been reclassified to conform to this presentation. For information regarding the presentation of trading and marketing activities on a net basis, see Note 2(t). Revenues, fuel and cost of gas sold expense and purchased power expense have been reclassified to conform to this presentation. Accordingly, the unaudited quarterly information for each of the interim periods for 2001 and the interim periods ended March 31, 2002 and June 30, 2002 has been reclassified to conform to this presentation. The effect on revenues was a net reduction of $7.1 billion, $6.2 billion, $6.3 billion and $5.0 billion for the interim periods ended March 31, 2001, June 30, 2001, September 30, 2001 and December 31, 2001, respectively. The effect on revenues was a net reduction of $5.2 billion and $6.2 billion for the interim periods ended March 31, 2002 and June 30, 2002, respectively.

The quarterly operating results incorporate the results of operations of Orion Power from our February 2002 acquisition date as discussed in note 5(a). The variances in revenues from quarter to quarter for 2001 and 2002 were primarily due to (a) the Orion Power acquisition (for 2002 only), (b) the seasonal fluctuations in demand for electric energy and energy services, (c) changes in energy commodity prices and (d) hedge ineffectiveness related to certain long-term forward contracts for the sale of power in the California market through December 2006 (for 2001 only). Changes in operating income (loss) and net income (loss) from quarter to quarter for 2001 and 2002 were primarily due to:

- the seasonal fluctuations in demand for electric energy and energy services;
- changes in energy commodity prices;
- the timing of maintenance expenses on electric generation plants; and
- provisions related to energy sales and refunds in California.

In addition, operating income and net income changed from quarter to quarter in 2001 by:

- a $100 million pre-tax, non-cash charge in the first quarter of 2001 relating to the redesign of some of CenterPoint's benefits plans in anticipation of our separation;
- write-offs recorded in the fourth quarter of 2001 related to Enron of $85 million;
- $54 million pre-tax charges in 2001 related to exiting the communications business;
- hedge ineffectiveness related to certain long-term forward contracts for the sale of power in the California market through December 2006;
- a $51 million pre-tax gain in the second quarter of 2001 related to the valuation of our interest in NEA; and
- a $37 million gain on the stranded cost indemnification settlement in the fourth quarter of 2001.

Also, operating income (loss) and net income (loss) changed from quarter to quarter in 2002 by:

- the impact of the Orion Power acquisition;
- a $128 million accrual recorded in the third and fourth quarters of 2002 for a payment to CenterPoint;
- a one-time $109 million pre-tax gain resulting from the amendment of our stranded cost electricity supply contracts in the second quarter of 2002;
- a $47 million pre-tax, non-cash charge in the third quarter of 2002 relating to the accounting settlement of certain benefit obligations associated with our separation from CenterPoint;
- impairment charges of $32 million pre-tax relating to certain cost method investments ($27 million pre-tax in the fourth quarter) in 2002;
- change in refund reserves, credit provisions and interest income (all net) of gain (loss) recognized of $33 million, $(29) million, $(15) million and $(98) million (all pre-tax) in the first, second, third and fourth quarters, respectively, during 2002 related to energy sales in the California wholesale market in 2000 and 2001 (see note 14(i));
- costs related to plant cancellations and equipment impairments in the second and third quarters of 2002;
- a $45 million tax accrual on future distributions from NEA in the third quarter of 2002 (only impacted net loss);
- a cumulative effect of an accounting change of $234 million, net of tax, in the first quarter of 2002 (only impacted net loss); and
- a $482 million goodwill impairment of our European energy segment in the fourth quarter of 2002.

(20) REPORTABLE SEGMENTS

We have identified the following reportable segments: retail energy, wholesale energy, European energy and other operations. For descriptions of the financial reporting segments, see note 1. In February 2003, we signed a share purchase agreement to sell our European energy operations. See note 21(b) for further discussion. Our determination of reportable segments considers the strategic operating units under which we manage sales, allocate resources and assess performance of various products and services to wholesale or retail customers.

Financial information for Orion Power and REMA are included in the segment disclosures only for periods beginning on their respective acquisition dates. Beginning in the first quarter of 2002, we began to evaluate segment performance on earnings (loss) before interest expense, interest income and income taxes (EBIT). Prior to 2002, we evaluated performance on operating income. EBIT is not defined under accounting principles generally accepted in the United States of America (GAAP), and should not be considered in isolation or as a substitute for a measure of performance prepared in accordance with GAAP and is not indicative of operating income (loss) from operations as determined under GAAP. There were no material intersegment revenues during 2000, 2001 and 2002.

Long-lived assets include net property, plant and equipment, net goodwill, net other intangibles and equity investments in unconsolidated subsidiaries.

Financial data for business segments, products and services and geographic areas are as follows:

	Retail Energy	Wholesale Energy	European Energy	Other Operations	Eliminations	Consolidated
			(in millions)			
As of and for the year ended December 31, 2000:						
Revenues from external customers	$ 64	$ 2,661	$ 544	$ 6	$ —	$ 3,275
Trading margins	—	198	2	—	—	200
Depreciation and amortization	4	108	76	6	—	194
Operating (loss) income	(70)	505	84	(61)	—	458
EBIT	(70)	572	89	(83)	—	508
Total assets	131	10,766	2,473	105	—	13,475
Equity investments in unconsolidated subsidiaries	—	109	—	—	—	109
Expenditures for long-lived assets	22	1,966	995	59	—	3,042
As of and for the year ended December 31, 2001:						
Revenues from external customers	114	5,382	623	11	—	6,130
Trading margins	74	304	(9)	—	—	369
Depreciation and amortization	11	118	76	42	—	247
Operating (loss) income	(13)	907	56	(180)	—	770
EBIT	(13)	916	113	(158)	—	858
Total assets	391	7,671	3,380	645	(368)	11,719
Equity investments in unconsolidated subsidiaries	—	88	299	—	—	387
Expenditures for long-lived assets	117	658	21	44	—	840
As of and for the year ended December 31, 2002:						
Revenues from external customers	4,201	6,433	611	3	—	11,248
Trading margins	152	137	21	—	—	310
European energy goodwill impairment	—	—	482	—	—	482
Depreciation and amortization	26	337	58	15	—	436
Operating income (loss)	524	24	(371)	(57)	—	120
EBIT	520	68	(356)	(80)	—	152
Total assets	1,517	12,803	2,811	916	(410)	17,637
Equity investments in unconsolidated subsidiaries	—	103	210	—	—	313
Expenditures for long-lived assets	33	3,495	19	77	—	3,624

	As of and for the Year Ended December 31,		
	2000	2001	2002
		(in millions)	
Reconciliation of Operating Income to EBIT and EBIT to Net Income (Loss):			
Operating income	$ 458	$ 770	$ 120
(Losses) gains from investments, net	(17)	22	(24)
Income of equity investment of unconsolidated subsidiaries	43	57	23
Other income, net	24	9	33
EBIT	508	858	152
Interest expense	(42)	(63)	(304)
Interest income	18	27	35
Interest (expense) income—affiliated companies, net	(173)	12	5
Income (loss) before income taxes and cumulative effect of accounting change	311	834	(112)
Income tax expense	(95)	(274)	(214)
Cumulative effect of accounting change, net of tax	—	3	(234)
Extraordinary item, net of tax	7	—	—
Net income (loss)	$ 223	$ 563	$ (560)
Revenues by Products and Services:			
Retail energy products and services	$ 64	$ 114	$ 4,201
Wholesale energy and energy related sales	3,205	6,005	7,044
Energy trading margins	200	369	310
Other	6	11	3
Total	$3,475	$6,499	$11,558
Revenues and Long-Lived Assets by Geographic Areas:			
Revenues:			
United States(1)	$2,911	$5,908	$10,921
Netherlands(2)	546	614	632
Canada(3)	18	(23)	5
Total	$3,475	$6,499	$11,558
Long-lived assets:			
United States	$3,078	$3,728	$ 9,674
Netherlands	2,371	2,424	1,857
Total	$5,449	$6,152	$11,531

(1) For 2000, 2001 and 2002, revenues include trading margins of $180 million, $401 million and $284 million, respectively.
(2) For 2000, 2001 and 2002, revenues include trading margins of $2 million, ($9) million and $21 million, respectively.
(3) For 2000, 2001 and 2002, revenues include trading margins of $18 million, ($23) million and $5 million, respectively.

(21) SUBSEQUENT EVENTS

(a) Domestic Refinancings.

During March 2003, we refinanced our (a) $1.6 billion senior revolving credit facilities (see note 9(a)), (b) $2.9 billion 364-day Orion acquisition term loan (see note 9(a)), and (c) $1.425 billion construction agency financing commitment (see note 14(b)), and we obtained a new $300 million senior priority revolving credit facility. The refinancing combined the existing credit facilities into a $2.1 billion senior secured revolving credit facility, a $921 million senior secured term loan, and a $2.91 billion senior secured term loan. The refinanced credit facilities mature in March 2007. The $300 million senior priority revolving credit facility matures on the earlier of our acquisition of Texas Genco or December 15, 2004. The $300 million senior priority revolving credit facility is secured with a first lien on substantially all of our contractually and legally available assets. The other facilities totaling $5.93 billion are secured with a second lien on such assets. Our subsidiaries guarantee both the refinanced credit facilities and the senior priority revolving credit facility to the extent contractually and legally permitted.

In connection with the refinancing, we were required to make a prepayment of $350 million under the senior revolving credit facility. This prepayment was made from cash on hand and is available to be reborrowed under the senior revolving credit facility. We must use the proceeds of any loans under the senior priority revolving credit facility solely to secure or prepay our ongoing commercial and trading obligations and not for other general corporate or working capital purposes. We must use the proceeds of any loans under the other senior revolving credit facility solely for working capital and other general corporate purposes. We are not permitted to use the proceeds from loans under any of these facilities to acquire Texas Genco.

The loans under the refinanced credit facilities bear interest at LIBOR plus 4.0% or a base rate plus 3.0% and the loans under the senior priority revolving credit facility bear interest at LIBOR plus 5.5% or a base rate plus 4.5%. If the refinanced credit facilities are not permanently reduced by $500 million, $1.0 billion and $2.0 billion (cumulatively) by May 2004, 2005 and 2006, respectively, we must pay a fee ranging from 0.50% to 1.0% of the amount of the refinanced credit facilities still outstanding on each such date. Additionally, we are required to make principal prepayments on the refinanced facilities (a) of $500 million by no later than May 2006 and (b) with proceeds from certain asset sales and issuances of securities and with certain cash flows in excess of a threshold amount. Both the refinanced credit facilities and the new senior priority revolving credit facility are evidenced by the same credit agreement, which contains numerous financial, affirmative, and negative covenants. Financial covenants include maintaining a debt to earnings before interest, taxes, depreciation, amortization and rent (EBITDAR) ratio of a certain maximum amount and a EBITDAR to interest ratio of a certain minimum amount. Our March 2003 credit facilities restrict our ability to take specific actions, subject to numerous exceptions that are designed to allow for the execution of our business plans in the ordinary course, including the completion of all four of the power plants currently under construction, the preservation and optimization of all of our existing investments in the retail energy and wholesale energy businesses, the ability to provide credit support for our commercial obligations and the possible exercise of the option to acquire a majority interest in Texas Genco, and the financings related thereto. Such restrictions include our ability to (a) encumber our assets, (b) enter into business combinations or divest our assets, (c) incur additional debt or engage in sale and leaseback transactions, (d) pay dividends or prepay other debt, (e) make investments or acquisitions, (f) enter into transactions with affiliates, (g) make capital expenditures, (h) materially change our business, (i) amend our debt and other material agreements, (j) issue, sell or repurchase our capital stock, (k) allow distributions from our subsidiaries and (l) engage in certain types of trading activities. These covenants are not anticipated to materially restrict our ability to borrow funds or obtain letters of credit under the refinanced credit facilities or the senior priority credit facility. We must be in compliance with each of the covenants before we can

borrow under the revolving credit facilities. Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in us being required to repay these borrowings before their due date.

In connection with our March 2003 refinancing, we issued to the lenders warrants to acquire shares of our common stock that would represent 6.5% of our outstanding shares effective as of March 28, 2003 on a fully-diluted basis (after giving effect to such warrants). The exercise prices of the warrants are based on average market prices of our common stock during specified periods in proximity to the refinancing date. Of this 6.5%, warrants equal to 2.5% vested in March 2003, 2% will vest if the refinanced credit facilities have not been reduced by an aggregate of $1.0 billion by May 2005 and the remaining 2% will vest if the refinanced credit facilities have not been reduced by an aggregate of $2.0 billion by May 2006. The warrants are exercisable for a period of five years from the date they become vested.

We incurred approximately $150 million in financing costs (which excludes $15 million to be paid at maturity) and expensed approximately $33 million (of which $11 million was expensed in 2002 and $22 million was expensed in 2003) in fees and other costs related to our refinancing efforts.

(b) Sale of Our European Energy Operations.

In February 2003, we signed a share purchase agreement to sell our European energy operations to N.V. Nuon (Nuon), a Netherlands-based electricity distributor. Upon consummation of the sale, we expect to receive cash proceeds from the sale of approximately $1.2 billion (Euro 1.1 billion). The sales price is denominated in Euros; however, we have hedged our foreign currency exposure of our net investment in our European energy operations. See below for further discussion of the hedges. As additional consideration for the sale, we will also receive 90% of the dividends and other distributions in excess of approximately $115 million (Euro 110 million) paid by NEA to REPGB following the consummation of the sale. The purchase price payable at closing assumes that our European energy operations will have, on the sale consummation date, net cash of at least $121 million (Euro 115 million). If the amount of net cash is less on such date, the purchase price will be reduced accordingly.

We intend to use the cash proceeds from the sale first to prepay the Euro 600 million bank term loan borrowed by Reliant Energy Capital (Europe), Inc. to finance a portion of the acquisition costs of our European energy operations. The maturity date of the credit facility, which originally was scheduled to mature in March 2003, has been extended (see notes 9(a) and 21(c)). We intend to use the remaining cash proceeds of approximately $0.5 billion (Euro 0.5 billion) to partially fund our option to acquire Texas Genco in 2004 (see note 4(b)). However, if we do not exercise the option, we will use the remaining cash proceeds to prepay debt.

The sale is subject to the approval of the Dutch and German competition authorities. We anticipate that the consummation of the sale will occur in the summer of 2003. No assurance can be given that we will obtain the approval of the Dutch and German competition authorities or that such approvals can be obtained in a timely manner.

As of December 31, 2002, our European energy operations had current assets of $650 million, net property, plant and equipment of $1.6 billion, other long-term assets of $429 million, $1.1 billion of current liabilities (including debt of $631 million), long-term debt of $37 million and other long-term liabilities of $676 million. These amounts exclude net intercompany receivables and payables that will not be purchased by Nuon. We recognized a loss of approximately $0.4 billion in the first quarter of 2003 in connection with the anticipated sale. We do not anticipate that there will be a Dutch or United States income tax benefit realized by us as a result of

this loss. We will recognize contingent payments, if any, in earnings upon receipt. In the first quarter of 2003, we began to report the results of our European energy operations as discontinued operations in accordance with SFAS No. 144. For information regarding goodwill impairments of our European energy segment recognized in the first and fourth quarters of 2002 of $234 million and $482 million, respectively, see note 6.

In March 2003, we adjusted the hedge of our net investment in our European energy operations to Euro 1.5 billion by selling foreign currency options of Euro 400 million and purchasing Euro 520 million of foreign currency options which expire in June 2003.

(c) Extension of Euro 600 Million Bank Term Loan Facility.

In March 2003, we reached an agreement with our lenders to extend the maturity date of the Euro 600 million bank term loan facility of Reliant Energy Capital (Europe), Inc., originally scheduled to mature on March 3, 2003. Based on the terms of the extension, we will repay this term loan on the first to occur of (a) completion of the above mentioned sale of our European energy operations to Nuon, (b) December 31, 2003 and (c) the earlier of the maturity dates of the two REPGB facilities, which are both July 2003, as they may be extended. If the sale of our European energy operations does not occur prior to July 2003, we will be required to repay this term loan in July 2003 unless prior to that date we are able to obtain an extension of REPGB's credit facilities. If the sale of our European energy operations does not close prior to the maturity of these facilities, REPGB anticipates extending these credit facilities.

In order to extend the Euro 600 million facility, we provided the following additional security to the lenders:

- a guarantee of the facility from Reliant Energy (Europe), Inc.;
- security over certain intercompany payables from our European energy operations (a portion of which will be repaid at consummation of the sale) and the bank accounts into which Nuon will deposit the cash proceeds of the sale; and
- a pledge of 65% of the shares in Reliant Energy Europe B.V., the holding company of our European energy operations, which pledge will be released upon the consummation of the sale.

In addition, we agreed to increase the interest rate under this credit facility to EURIBOR plus a margin of 4.0% per year, 2.0% of which is payable monthly and 2.0% of which will be paid in the event that the sale of our European energy operations to Nuon does not occur. We pre-funded interest under the facility through a security account, initially in an amount of approximately $18 million (Euro 17 million) and, thereafter, we will replenish this account in an amount equal to at least two months' interest service coverage under the facility.

(d) Price to Beat Fuel Factor Adjustment.

In March 2003, the PUCT approved our request to increase the price to beat fuel factor for residential and small commercial customers based on a 23.4% increase in the price of natural gas from our previous increase in December 2002. The approved increase was based on a 10 trading-day, average forward 12-month natural gas price of $4.956 per MMbtu (one million British thermal units). The increase represents an 8.2% increase in the total bill of a residential customer using an average 12,000 kilowatt hours per year. For additional information regarding the current price to beat fuel factor, see note 14(f).

(e) Interest Rate Caps.

During January 2003, we purchased three-month LIBOR interest rate caps to hedge our future floating rate risk associated with various credit facilities. We have hedged $4.0 billion for the period from July 1 to December 31, 2003, $3.0 billion for 2004 and $1.5 billion for 2005. The LIBOR interest rates are capped at a weighted average rate of 2.06% for the period from July 1 to December 31, 2003, 3.18% for 2004 and 4.35% for 2005. These interest rate caps qualify for hedge accounting under SFAS No. 133 with any changes in fair market value recorded to other comprehensive income (loss).

(f) Cash Collateralized Letter of Credit Facility.

In January 2003, we entered into a $200 million cash-secured, revolving letter of credit facility with a financial institution. Outstanding letters of credit are required to be 103% cash collateralized. Under the facility, letters of credit may be issued until January 29, 2004 and may remain outstanding until January 29, 2005. The facility is not cross-defaulted to any other facility. The facility agreement contains certain limited affirmative and negative covenants, but no financial covenants. This letter of credit facility is subject to monthly letter of credit and unused lines fees that are calculated on the outstanding letters of credit and the unused commitment, respectively.

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RELIANT RESOURCES, INC.

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF OPERATIONS
(Thousands of Dollars)

	Year Ended December 31, 2001	Year Ended December 31, 2002
(Expenses) Income:		
General, administrative and depreciation, net	$(104,382)	$ (53,596)
Equity in earnings (loss) of investments in subsidiaries	567,032	(523,524)
Foreign currency translation loss from intercompany note receivable	(15,839)	—
Interest expense	(9,625)	(116,197)
Interest income		8,628
Interest income—CenterPoint, net	2,523	2,657
Interest income—subsidiaries, net	126,576	103,322
Income (Loss) Before Income Taxes	566,285	(578,710)
Income Tax (Expense) Benefit	(2,934)	18,898
Net Income (Loss)	$ 563,351	$(559,812)

See Notes to the Condensed Financial Statements and Reliant Resources' Consolidated Financial Statements

RELIANT RESOURCES, INC.

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED BALANCE SHEETS
(Thousands of Dollars)

	December 31, 2001	December 31, 2002
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,262	$ 656,966
Advances to and notes receivable from subsidiaries, net	371,894	817,128
Accounts and notes receivable from CenterPoint, net	386,186	25,887
Federal income tax receivable	—	94,792
Accumulated deferred income taxes	—	17,585
Prepayments and other current assets	1,141	5,161
Total current assets	760,483	1,617,519
Property, Plant and Equipment, net	59,140	120,893
Other Assets:		
Advances to and notes receivable from subsidiaries, net	2,537,233	2,539,275
Investments in subsidiaries	2,751,700	5,714,872
Accumulated deferred income taxes	17,148	25,822
Restricted cash	—	7,000
Other	36,806	36,512
Total other assets	5,342,887	8,323,481
Total Assets	$6,162,510	$10,061,893
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ —	$ 350,000
Accounts and other payables	77,540	72,467
Other	26,269	25,850
Total current liabilities	103,809	448,317
Benefit Obligations and Other Liabilities	75,069	44,688
Long-term Debt	—	3,916,000
Commitments and Contingencies (note 5)		
Stockholders' Equity:		
Preferred stock; par value $0.001 per share (125,000,000 shares authorized; none outstanding)	—	—
Common Stock, par value $0.001 per share (2,000,000,000 shares authorized; 299,804,000 issued)	61	61
Additional paid-in capital	5,789,869	5,836,957
Treasury stock at cost, 11,000,000 and 9,198,766 shares	(189,460)	(158,483)
Retained earnings	563,351	3,539
Accumulated other comprehensive loss	(180,189)	(29,186)
Stockholders' equity	5,983,632	5,652,888
Total Liabilities and Stockholders' Equity	$6,162,510	$10,061,893

See Notes to the Condensed Financial Statements and Reliant Resources' Consolidated Financial Statements

RELIANT RESOURCES, INC.

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF CASH FLOWS
(Thousands of Dollars)

	Year Ended December 31, 2001	Year Ended December 31, 2002
Cash Flows from Operating Activities:		
Net income (loss)	$ 563,351	$ (559,812)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Deferred income taxes	(39,840)	35,862
Equity in (earnings) loss of investment in subsidiaries	(567,032)	523,524
Curtailment and related benefit enhancement	99,523	—
Accounting settlement for certain benefit plans	—	47,356
Ineffectiveness of interest rate hedges	—	16,037
Other, net	—	9,993
Changes in other assets and liabilities:		
Receivables from subsidiaries, net	(48,365)	(4,779)
Receivables from CenterPoint, net	(4,332)	1,196
Federal income tax receivable/payable	6,149	(100,941)
Other current assets	(1,141)	(4,020)
Other assets	(4,706)	(34,448)
Accounts and other payable	32,730	(5,073)
Other current liabilities	20,120	17,384
Settlement of interest rate hedges	—	(55,048)
Settlement of hedges of net investment in foreign subsidiaries	—	(162,432)
Other liabilities	5,422	276
Net cash provided by (used in) operating activities	61,879	(274,925)
Cash Flows from Investing Activities:		
Capital expenditures	(44,278)	(76,238)
Business acquisitions, net of cash acquired	—	(2,963,801)
Investments in, advances to and notes receivable from subsidiaries, net	(1,150,540)	(674,801)
Net cash used in investing activities	(1,194,818)	(3,714,840)
Cash Flows from Financing Activities:		
Proceeds from debt	—	4,266,000
Proceeds from issuance of stock, net	1,696,074	—
Purchase of treasury stock	(189,460)	—
Payments of financing costs	—	(15,978)
Change in notes receivable with CenterPoint, net	(381,854)	381,854
Contributions from CenterPoint	9,441	—
Other, net	—	13,593
Net cash provided by financing activities	1,134,201	4,645,469
Net Increase in Cash and Cash Equivalents	1,262	655,704
Cash and Cash Equivalents at Beginning of Year	—	1,262
Cash and Cash Equivalents at End of Year	$ 1,262	$ 656,966
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest	$ 11,150	$ 84,267
Income taxes paid (income tax refunds received, net)	32,729	(32,737)

See Notes to the Condensed Financial Statements and Reliant Resources' Consolidated Financial Statements

RELIANT RESOURCES, INC.

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT
NOTES TO CONDENSED FINANCIAL STATEMENTS

(1) BACKGROUND AND BASIS OF PRESENTATION

These condensed parent company financial statements have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X, as the restricted net assets of Reliant Resources' subsidiaries exceed 25% of the consolidated net assets of Reliant Resources. This information should be read in conjunction with the Reliant Resources and subsidiaries consolidated financial statements included elsewhere in this filing.

Reliant Resources, a Delaware corporation, was incorporated in August 2000 with 1,000 shares of common stock, which were owned by Reliant Energy. Effective December 31, 2000, Reliant Energy consolidated its unregulated operations under Reliant Resources (Consolidation). A subsidiary of CenterPoint, RERC Corp., transferred some of its subsidiaries, including its trading and marketing subsidiaries, to Reliant Resources. In connection with the transfer from RERC Corp., Reliant Resources paid $94 million to RERC Corp. Also effective December 31, 2000, CenterPoint transferred its wholesale power generation businesses, its unregulated retail electric operations, its communications business and most of its other unregulated businesses to Reliant Resources. In accordance with accounting principles generally accepted in the United States of America, the transfers from RERC Corp. and CenterPoint were accounted for as a reorganization of entities under common control. In addition, corporate support and executive officers transferred to Reliant Resources on January 1, 2001. As such, condensed financial information has not been presented for Reliant Resources for 2000.

Reliant Resources' 100% investments in its subsidiaries have been recorded using the equity basis of accounting in the accompanying condensed parent company financial statements. The condensed statements of operations and statements of cash flows are presented for 2001 and 2002.

(2) CERTAIN RELATED PARTY TRANSACTIONS

(a) Income Taxes

Prior to October 1, 2002, Reliant Resources was included in the consolidated federal income tax returns of CenterPoint and calculated its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint. Prior to October 1, 2002, current federal income taxes were payable to or receivable from CenterPoint. Subsequent to September 30, 2002, Reliant Resources will file a separate federal income tax return. As of October 1, 2002, Reliant Resources entered into a tax sharing agreement with certain of its subsidiaries. Pursuant to the tax sharing agreement, Reliant Resources pays all federal income taxes on behalf of its subsidiaries included in the consolidated tax group and is entitled to any related tax refunds. The difference between Reliant Resources' current federal income tax expense or benefit, as calculated on a separate return basis, and related amounts payable to/receivable from the Internal Revenue Service is reflected as an increase/decrease to the investments in subsidiaries account and is reflected on the subsidiaries' books as adjustments to their equity. During 2002, Reliant Resources made equity contributions to its subsidiaries for deemed distributions related to current federal income taxes of $64 million.

(b) Allocations of General, Administrative and Depreciation Costs and Cash Management Function

Certain general, administrative and depreciation costs are allocated from Reliant Resources to its subsidiaries. For 2001 and 2002, these allocations were $136 million and $187 million, respectively, and are netted in the applicable line on the condensed statements of operations. The unpaid allocations are reflected as a component of current advances to and notes receivable from subsidiaries, net in the condensed balance sheets.

Through June 30, 2002, a subsidiary of CenterPoint had established a "money fund" through which Reliant Resources could borrow or invest on a short-term basis. Also, during 2001, proceeds not utilized from the IPO

were advanced to this subsidiary of CenterPoint. Reliant Resources earned interest income from CenterPoint for these short-term investments. After the IPO, Reliant Resource established a similar "money fund" or "central bank" through which its subsidiaries can borrow or invest on a short-term basis. The net amounts are included in current and long-term advances to and notes receivable from subsidiaries, net in the condensed balance sheets.

(3) RESTRICTED NET ASSETS OF SUBSIDIARIES

Certain of Reliant Resources' subsidiaries have restrictions on their ability to pay dividends or make intercompany loans and advances pursuant to their financing arrangements. The amount of restricted net assets of Reliant Resources' subsidiaries as of December 31, 2002 is approximately $3.3 billion. The restrictions are on the net assets of Orion Capital, Liberty and Channelview. Orion MidWest and Orion NY are indirect wholly-owned subsidiaries of Orion Capital.

It is the customary practice of Reliant Resources to loan monies to and borrow monies from certain of its subsidiaries through the use of the "central bank" as described in note 2(b) above. However, there were no legally declared cash dividends or return of shareholder's equity to Reliant Resources from its subsidiaries in 2001 and 2002.

(4) BANKING OR DEBT FACILITIES

For a discussion of Reliant Resources' banking or debt facilities, see note 9 to Reliant Resources' consolidated financial statements. Reliant Resources' debt obligations are included in the Other Operations segment data in note 9 to Reliant Resources' consolidated financial statements. See note 21(a) to Reliant Resources' consolidated financial statements for a discussion of certain debt facilities, which were refinanced in March 2003.

Maturities of Reliant Resources' debt obligations outstanding as of December 31, 2002, under the refinanced debt facilities were as follows (in millions):

2003	$ 350
2004	—
2005	—
2006	500
2007	3,416
Total	$4,266

As discussed in note 21(a) to Reliant Resources' consolidated financial statements, in connection with the refinancing in March 2003, we were required to make a prepayment of $350 million under the senior revolving credit facility. As such, this amount is classified as current in the condensed balance sheet. This prepayment was made from cash on hand and is available to be reborrowed under the senior revolving credit facility.

(5) COMMITMENTS AND CONTINGENCIES

For a discussion of Reliant Resources' commitments and contingencies, see note 14 to Reliant Resources' consolidated financial statements.

(a) Guarantees

Reliant Resources has issued guarantees in conjunction with certain performance agreements and commodity and derivative contracts and other contracts that provide financial assurance to third parties on behalf of a subsidiary or an unconsolidated third-party. The guarantees on behalf of subsidiaries are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the relevant subsidiary's intended commercial purposes.

The following table details Reliant Resources' various guarantees, including the maximum potential amounts of future payments, assets held as collateral and the carrying amount of the liabilities recorded on the balance sheet, if applicable, as of December 31, 2002:

Type of Guarantee	Maximum Potential Amount of Future Payments	Assets Held as Collateral	Carrying Amount of Liability Recorded on Balance Sheet
		(in millions)	
Trading and hedging obligations (1)	$5,012	$ —	$ —
Guarantees under construction agency agreements (2)	1,325	—	—
Payment and performance obligations under power purchase agreements for power generation assets and renewables (3)	339	—	—
Payment and performance obligations under service contracts (4)	101	—	—
Non-qualified benefits of CenterPoint's retirees (5)	58	—	—
Sale of electricity to large commercial, industrial and institutional customers (6)	48	—	—
Total Guarantees	$6,883	$ —	$ —

(1) Reliant Resources has guaranteed the performance of certain of its wholly-owned subsidiaries' trading and hedging obligations. These guarantees were provided to counterparties in order to facilitate physical and financial agreements in electricity, gas, oil, transportation and related commodities and services. These guarantees have varying expiration dates. The fair values of the underlying transactions are included in Reliant Resources' subsidiaries' balance sheets.

(2) See note 14(b) to Reliant Resources' consolidated financial statements for discussion of Reliant Resources' guarantees under the construction agency agreements. These guarantees were terminated in March 2003; see note 21(a) to Reliant Resources' consolidated financial statements.

(3) Reliant Resources has guaranteed the payment and performance obligations of certain wholly-owned subsidiaries arising under certain power purchase agreements. These guarantees have varying expiration dates through 2012.

(4) Reliant Resources has guaranteed the payment obligations of certain wholly-owned subsidiaries arising under long-term service agreements for certain facilities. These guarantees expire over varying years through 2017.

(5) Reliant Resources has guaranteed, in the event CenterPoint becomes insolvent, certain non-qualified benefits of CenterPoint's and its subsidiaries' existing retirees at the Distribution. See note 4(a) to Reliant Resources' consolidated financial statements.

(6) Reliant Resources has guaranteed commodity related payments for certain wholly-owned subsidiaries' sale of electricity to large commercial, industrial and institutional customers to facilitate the physical and financial transactions of electricity services. These guarantees expire on various dates through December 31, 2003.

Unless otherwise noted, failure by the primary obligor to perform under the terms of the various agreements and contracts guaranteed may result in the beneficiary requesting immediate payment from Reliant Resources. To the extent liabilities exist under the various agreements and contracts that Reliant Resources guarantees, such liabilities are recorded in Reliant Resources' subsidiaries' balance sheets at December 31, 2002. Management believes the likelihood that Reliant Resources would be required to perform or otherwise incur any significant losses associated with any of these guarantees is remote.

Reliant Resources has entered into contracts that include indemnification provisions as a routine part of its business activities. Examples of these contracts include asset purchase and sale agreements, lease agreements, procurement agreements and certain debt agreements. In general, these provisions indemnify the counterparty for matters such as breaches of representations and warranties and covenants contained in the contract and/or against third party liabilities. In the case of debt agreements, Reliant Resources generally indemnifies against liabilities that arise from the preparation, administration or enforcement of the agreement. Under the indemnifications, the maximum potential amount is not estimable given that the magnitude of any claims under the indemnifications would be a function of the extent of damages actually incurred, which is not practicable to estimate unless and until the event occurs. Management believes the likelihood of making any material payments under these provisions is remote. For additional discussion of certain indemnifications by Reliant Resources, see notes 4(a) and 14(h) to Reliant Resources' consolidated financial statements.

(b) Leases

Reliant Resources has entered into various long-term non-cancelable operating leases, such as rental agreements for building space, including the office space lease discussed in note 14(a) to Reliant Resources' consolidated financial statements, data processing equipment and other agreements. The following table sets forth information concerning these cash obligations as of December 31, 2002 (in millions):

2003	$ 21
2004	20
2005	17
2006	17
2007	17
2008 and beyond	203
Total	$295

RELIANT RESOURCES, INC. AND SUBSIDIARIES

SCHEDULE II—RESERVES

For the Three Years Ended December 31, 2002

(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts(1)	Deductions from Reserves(2)	Balance at End of Period
For the Year Ended December 31, 2000:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 7,803	$ 43,100	$ —	$ 563	$51,466
Reserves deducted from trading and marketing assets	11,511	54,621	—	—	66,132
Reserves for accrue-in-advance major maintenance	47,809	41,306	(787)	(61,253)	27,075
Reserves for inventory	5,716	—	17,053	(15,941)	6,828
Reserves for severance	17,760	—	20,065	(5,325)	32,500
Deferred tax assets valuation	3,028	17,232	—	—	20,260
For the Year Ended December 31, 2001:					
Accumulated provisions:					
Uncollectible accounts receivable	51,466	38,274	1,455	(1,487)	89,708
Reserves deducted from trading and marketing assets	66,132	31,717	—	—	97,849
Reserves for accrue-in-advance major maintenance	27,075	2,383	(663)	(9,419)	19,376
Reserves for inventory	6,828	51	(6,424)	—	455
Reserves for severance	32,500	5,003	(1,802)	(16,050)	19,651
Deferred tax assets valuation	20,260	(4,628)	—	—	15,632
For the Year Ended December 31, 2002:					
Accumulated provisions:					
Uncollectible accounts receivable	89,708	21,190	2,797	(44,596)	69,099
Reserves deducted from trading and marketing assets	97,849	(34,938)	—	(17,437)	45,474
Reserves for accrue-in-advance major maintenance	19,376	14,211	2,841	(12,126)	24,302
Reserves for inventory	455	3,177	208	(148)	3,692
Reserves for severance	19,651	30,621	2,832	(29,617)	23,487
Deferred tax assets valuation	15,632	25,984	29,714	—	71,330

(1) Charged to other accounts represents obligations acquired through business acquisitions and effects of foreign currency exchange rate changes.

(2) Deductions from reserves represent losses or expenses for which the respective reserves were created. In the case of the uncollectible accounts reserve, such deductions are net of recoveries of amounts previously written off.

* * *

INDEPENDENT AUDITORS' REPORT

To the Members of El Dorado Energy, LLC

We have audited the accompanying balance sheets of El Dorado Energy, LLC (the "Company") as of December 31, 2002 and 2001, and the related statements of operations, members' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2002. 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 in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2002 and 2001, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 8 to the financial statements, the Company changed its method of accounting for derivative instruments and hedging activities in 2001.

DELOITTE & TOUCHE LLP

Houston, Texas
March 31, 2003

EL DORADO ENERGY, LLC

STATEMENTS OF OPERATIONS

(Thousands of Dollars)

	Year Ended December 31,		
	2002	2001	2000
Revenues	$100,680	$132,574	$260,460
Expenses:			
Fuel	79,918	110,623	129,059
Purchased power	1,320	(280)	4,743
Operations and maintenance	12,706	17,028	6,500
Taxes other than income and insurance	2,244	1,344	1,214
Depreciation	8,415	8,415	4,932
Total Expenses	104,603	137,130	146,448
Operating Income (Loss)	(3,923)	(4,556)	114,012
Other Income	43,719	246	—
Income (Loss) Before Interest Expense	39,796	(4,310)	114,012
Interest Expense, Net	(8,965)	(7,725)	(6,461)
Net Income (Loss)	$ 30,831	$ (12,035)	$107,551

See Notes to the Financial Statements

EL DORADO ENERGY, LLC

BALANCE SHEETS

(Thousands of Dollars)

	December 31, 2002	December 31, 2001
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 34,305	$ 17,687
Restricted cash	4,432	—
Current portion of debt service reserve fund	7,154	—
Accounts receivable	2,192	1,563
Inventories	1,906	1,832
Prepayments and other current assets	842	456
Prepaid long-term maintenance	9,009	—
Total current assets	59,840	21,538
Property, Plant and Equipment, Net	224,035	227,906
Other Assets:		
Debt issuance costs, net	4,335	4,675
Debt service reserve fund	7,009	14,415
Non-trading derivative asset	—	184
Total other assets	11,344	19,274
Total Assets	$295,219	$268,718
LIABILITIES AND MEMBERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 6,312	$ 5,918
Accrued liabilities	4,000	2,474
Non-trading derivative liability	4,084	3,160
Total current liabilities	14,396	11,552
Other Liabilities:		
Non-trading derivative liability	2,912	—
Total other liabilities	2,912	—
Long-term Debt	138,864	145,176
Commitments and Contingencies (Note 13)		
Members' Equity:		
Common stock	2	2
Members' capital contributions	125,022	125,022
Retained earnings (deficit)	21,018	(9,813)
Accumulated other comprehensive loss	(6,995)	(3,221)
Total members' equity	139,047	111,990
Total Liabilities and Members' Equity	$295,219	$268,718

See Notes to the Financial Statements

EL DORADO ENERGY, LLC

STATEMENTS OF CASH FLOWS

(Thousands of Dollars)

	Year Ended December 31,		
	2002	2001	2000
Cash Flows from Operating Activities:			
Net income (loss)	$ 30,831	$(12,035)	$107,551
Adjustments to reconcile net income (loss) to net cash provided by operations:			
Depreciation	8,415	8,415	4,932
Amortization of debt issuance costs	340	340	85
Net change in non-trading derivative assets and liabilities	245	(245)	—
Changes in assets and liabilities:			
Restricted cash	(4,432)	—	—
Accounts receivable	(629)	32,654	(31,902)
Inventories	(74)	(475)	(828)
Prepaid long-term maintenance	1,805	—	—
Other assets	(386)	(97)	(285)
Other current liabilities	1,526	335	924
Net cash flows provided by operating activities	37,641	28,892	80,477
Cash Flows from Investing Activities:			
Capital expenditures	(9,107)	(1,954)	(6,707)
Performance guarantee settlements	(6,250)	(11,900)	19,900
Net cash flows (used in) provided by investing activities	(15,357)	(13,854)	13,193
Cash Flows from Financing Activities:			
Proceeds from long-term debt	—	—	8,800
Payments of long-term debt	(5,918)	(4,339)	(2,367)
Changes in debt service reserve	252	—	(14,415)
Capital contributions	—	16,977	6,899
Distributions	—	(67,056)	(35,856)
Net cash flows used in financing activities	(5,666)	(54,418)	(36,939)
Net Change in Cash and Cash Equivalents	16,618	(39,380)	56,731
Cash and Cash Equivalents, Beginning of Year	17,687	57,067	336
Cash and Cash Equivalents, End of Year	$ 34,305	$ 17,687	$ 57,067
Supplemental Disclosure of Cash Flow Information:			
Cash payments			
Interest (net of amounts capitalized)	$ 8,561	$ 7,344	$ 6,376

See Notes to the Financial Statements

EL DORADO ENERGY, LLC

STATEMENTS OF MEMBERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

(Thousands of Dollars, except share amounts)

	Common Stock Shares	Common Stock Amount	Members' Capital Contributions	Retained Earnings (Deficit)	Accumulated Other Comprehensive Loss	Total Members' Equity	Comprehensive Income (Loss)
Balance December 31, 1999	2,000	$2	$101,146	$ (2,417)		$ 98,731	
Capital contributions			6,899			6,899	
Distributions to members				(35,856)		(35,856)	
Net income				107,551		107,551	$107,551
Comprehensive income							$107,551
Balance December 31, 2000	2,000	$2	$108,045	$ 69,278		$177,325	
Capital contributions			16,977			16,977	
Distributions to members				(67,056)		(67,056)	
Net loss				(12,035)		(12,035)	$ (12,035)
Other comprehensive loss:							
Cumulative effect of adoption of SFAS No. 133					$ 2,115	2,115	2,115
Deferred loss from cash flow hedge					(4,339)	(4,339)	(4,339)
Reclassification of net deferred gain from cash flow hedge in net loss					(997)	(997)	(997)
Comprehensive loss							$ (15,256)
Balance December 31, 2001	2,000	$2	$125,022	$ (9,813)	$(3,221)	$111,990	
Net income				30,831		30,831	$ 30,831
Other comprehensive loss:							
Deferred loss from cash flow hedge					(6,933)	(6,933)	(6,933)
Reclassification of net deferred loss from cash flow hedge in net income					3,159	3,159	3,159
Comprehensive income							$ 27,057
Balance December 31, 2002	2,000	$2	$125,022	$ 21,018	$(6,995)	$139,047	

See Notes to the Financial Statements

EL DORADO ENERGY, LLC

NOTES TO FINANCIAL STATEMENTS

For the years ended December 31, 2002, 2001, and 2000

1. NATURE OF BUSINESS

El Dorado Energy, LLC (the "Company"), a Delaware limited liability company formed on February 5, 1997, is jointly owned by Reliant Energy Power Generation, Inc. ("REPG") and Sempra Energy Power I ("SEP I") (collectively, the "Members"). REPG is a subsidiary of Reliant Resources, Inc. ("Reliant Resources"). SEP I is a subsidiary of Sempra Energy, Incorporated ("Sempra"). The Company was formed to develop, construct, and operate a 470 megawatt gas-fired power generation plant located in Boulder City, Nevada (the "Project"). The Company is governed by a management committee with equal representation from each of the Members.

Under the terms of the Company's limited liability agreement, the Company will continue until the earliest of (a) such time as all of the Company's assets have been sold or otherwise disposed of, (b) such time the Company's existence has been terminated or (c) September 2048. The Members are not personally liable for any amount in excess of their respective capital contributions, and are not liable for any of the debts and losses of the Company, except to the extent that a liability of the Company is founded upon results from an unauthorized act or activity of such Member.

Construction on the Project began in December 1997 and conditions for Provisional Performance Acceptance ("PPA") were achieved on May 3, 2000. Total cost of the project was $272 million and was funded through a $157.8 million credit agreement ("Credit Agreement") (see Note 3), and capital contributions received from the Members.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Reclassifications.

Some amounts from the previous years have been reclassified to conform to the 2002 presentation of financial statements. These reclassifications do not affect earnings.

Use of Estimates.

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

Market Risk and Uncertainties.

The Company is subject to the risk associated with price movements of energy commodities and the credit risk associated with the Company's risk management and hedging activities. For additional information regarding these risks, see Note 8. The Company is also subject to risks, among others, relating to the supply of fuel and sales of electricity, effects of competition, changes in interest rates, operation of deregulating power markets, seasonal weather patterns, technological obsolescence, and the regulatory environment in the United States.

Revenue Recognition.

Revenue consists primarily of energy sales. Power produced by the Project is sold on an equal basis to affiliates of Reliant Resources and Sempra under the provisions of separate power offtake agreements (See Note 7). Revenues not billed by month-end are accrued based upon estimated energy or services delivered.

Cash and Cash Equivalents.

Cash and cash equivalents include highly liquid investments with an original maturity of three months or less which are readily convertible to cash.

Restricted Cash.

Restricted cash includes cash that is restricted by a financing agreement but available to satisfy certain obligations. As of December 31, 2002 and 2001, the Company had $4.4 million and $0 in restricted cash, respectively, recorded in the balance sheet.

Inventory.

Inventory consists of materials and supplies held for consumption and is stated at lower of weighted average cost or market.

Debt Service Reserve Fund.

In accordance with the Credit Agreement, the Company is required to maintain a debt service reserve fund (see Note 3). The restricted funds are invested in a money market fund.

Debt Issuance Costs.

Costs associated with executing the Credit Agreement were deferred and are being amortized on a straight-line basis, which approximates the effective yield method, over the life of the term note under the Credit Agreement (15 years) (see Note 3). As of December 31, 2002 and 2001, the Company had $4.3 million and $4.7 million, respectively, of net deferred financing costs capitalized in its balance sheets.

Income Taxes.

The Company is a limited liability company not taxable for federal or state income tax purposes. Any taxable earnings or losses and certain other tax attributes are reported by the Members on their respective income tax returns.

Estimated Fair Value of Financial Instruments.

The recorded amounts for financial instruments of cash and cash equivalents, accounts receivable, debt service reserve fund, and long-term debt approximate fair value.

The Company enters into interest rate swap agreements to reduce its exposure to fluctuations in interest rates. These contracts are with a major financial institution and the risk of counterparty default is considered remote. The Company periodically reviews its credit risk.

The Company does not hold or issue derivative financial instruments for trading purposes.

See Note 8 for the Company's adoption of Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended ("SFAS No. 133") on January 1, 2001.

Property, Plant and Equipment.

Property, plant, and equipment are stated at cost. Depreciation is computed using the straight-line method over the estimated useful lives commencing when assets, or major components thereof, are placed in service. Property, plant, and equipment consisted of the following:

	Estimated Useful Lives (Years)	December 31, 2002	December 31, 2001
		(In thousands)	
Generation plant-in-service	30	$237,600	$233,307
Buildings	30	2,653	2,653
Land improvements	20	3,933	3,933
Machinery and equipment	5 to 10	1,360	1,360
Total property, plant, & equipment		245,546	241,253
Less: Accumulated depreciation		(21,511)	(13,347)
Property, plant and equipment, net		$224,035	$227,906

New Accounting Pronouncements

In August 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143"). SFAS No. 143 requires the fair value of a liability for legal asset retirement obligations to be recognized in the period in which it is incurred. When the liability is initially recorded, associated costs are capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. SFAS No. 143 requires entities to record a cumulative effect of change in accounting principle in the statement of operations in the period of adoption. The Company is currently evaluating the impact of SFAS No. 143 on its financial statements.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS No. 144"). SFAS No. 144 provides new guidance on the recognition of impairment losses on long-lived assets to be held and used or to be disposed of and also broadens the definition of what constitutes a discontinued operation and how the results of a discontinued operation are to be measured and presented. SFAS No. 144 supersedes SFAS No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" and Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions," while retaining many of the requirements of these two statements. Under SFAS No. 144, assets held for sale that are a component of an entity will be included in discontinued operations if the operations and cash flows will be or have been eliminated from the ongoing operations of the entity and the entity will not have any significant continuing involvement in the operations prospectively. SFAS No. 144 did not materially change the methods used by the Company to measure impairment losses on long-lived assets. The Company adopted SFAS No. 144 on January 1, 2002.

3. LONG-TERM DEBT

In September 1998, the Company entered into a Credit Agreement with a group of banks (the "Lenders") in order to finance a portion of the construction of the Project. The Credit Agreement provides for $157.8 million of construction and term loan financing. On September 29, 2000, all outstanding construction borrowings were converted into a term loan provided within the Credit Agreement. Principal payments under the term loan are payable in escalating amounts over the 15-year term of the loan. The following table sets forth the maturities of long-term debt for the Company as of December 31, 2002 (in millions):

2003	$ 6.3
2004	7.5
2005	9.1
2006	9.5
2007	9.5
2008 forward	103.3
Total	$145.2

Upon conversion into a term loan, the Credit Agreement required that the Company maintain a debt service reserve fund amount for the two succeeding calendar quarter periods. Debt service means for any period all principal payments, all interest payments, and all other fees made or required by the Company during such period under the Credit Agreement and any other loan document. This amount was increased to reserve twelve months of debt service as a commitment from the Company until the later of (a) the Project achieving Project Completion as defined in the Engineering, Procurement and Construction Agreement ("EPC") or (b) May 1, 2003. At December 31, 2002 and 2001, the Company had $14.2 million and $14.4 million, respectively, in the debt service reserve fund account.

Interest payments on the term note accrue at variable rates based upon either prime lending rates or the Eurodollar rate. At December 31, 2002 and 2001, the applicable interest rates under the Credit Agreement prior to consideration of the interest rate swaps (see Note 8) were 3.05% and 3.24%, respectively.

Borrowings under the Credit Agreement are secured by substantially all assets of the Company. The Credit Agreement contains customary covenants and default provisions, including limitations on, among other things, additional indebtedness, liens, establishment of an additional debt service reserve, retention, and major maintenance reserve accounts, and restricted payments. At December 31, 2002, the Company was in compliance with these covenants.

In 2001, the Company, the Lenders, the Members and affiliates of the Members entered into an Amended and Restated Waiver of Consent, and Amendment to the Credit Agreement (the "Amendment") which required the affiliates to purchase capacity and electric energy from the Company during the period from January 26, 2001 to June 30, 2001 (the "Waiver Period"), at certain prices designed to ensure that the Company maintains a Cash Flow to Debt Service Ratio of 1.5:1 as of any date of calculation for the immediately preceding quarter. The Amendment also provided that during any outage period the Cash Flow to Debt Service Ratio is satisfied by contributions of capital to the Company from the Members. Through the Amendment, the Lenders agreed to waive compliance with certain provisions of the Credit Agreement primarily relating to indices used in calculating electricity sales prices during the Waiver Period.

The $5 million working capital facility under the Credit Agreement expired in May 2002 and was replaced by two working capital facilities of $2.5 million each provided by Reliant Resources and Sempra. The Company pays a commitment fee based on the average daily, unused working capital commitment balance at a rate of 0.38% per annum. At December 31, 2002 and 2001, there were no borrowings under the working capital facility.

4. LEASE AGREEMENT

In April 1997, the Company entered into a 20-year lease agreement for certain parcels of land on which the Project is constructed. The Company has the option to extend the term of the lease through two renewal options of five years each and intends to exercise that option. The Company's obligations under this non-cancelable long-term operating lease as of December 31, 2002 are $0.8 million per year in each of 2003 through 2007 plus a contingent rental, which is based on 2% of net income, adjusted for principal payments and a 16% return on equity. Total lease expense was $0.8 million for each of the years ended December 31, 2002 and 2001 and $1.3 million for the year ended December 31, 2000. The payment of the contingent rental fee is dependent upon the Company achieving certain adjusted net income levels.

5. MEMBERS' EQUITY

The Company received capital contributions, pursuant to the Amendment to the Credit Agreement discussed in Note 3, from its Members as follows (See Note 7):

	2002	2001	2000
		(in thousands)	
REPG	$—	$ 8,489	$3,449
SEP I	—	8,488	3,450
Total	$—	$16,977	$6,899

6. EMPLOYEE BENEFIT PLANS

The Company participates in a defined contribution employee savings plan that is qualified under Section 401(a) of the Internal Revenue Code and ERISA Section 404(c). The Company contributes an amount equal to 4% of each employee's earnings into this account each year regardless of participation. It then matches 75% of employee contributions up to 6% of the respective employee's earnings (as defined in the savings plan). Participating employees may contribute up to 11% of their pre-tax earnings under the plan. Savings plan benefit expense for the years ended December 31, 2002, 2001 and 2000 was $176,000, $67,000, and $65,000, respectively.

7. RELATED-PARTY TRANSACTIONS

The Company has entered into technical service agreements with REPG and SEP I. REPG and SEP I bill the Company for the services based on the estimated cost of their employees who are working on the Project and for certain payments that were made on behalf of the Company. For the years ended December 31, 2002, 2001, and 2000 under the above agreements, the Company paid REPG $0.7 million, $1.7 million, and $3.6 million, respectively, and SEP I $26,300, $0.2 million, and $0.7 million, respectively.

In 2000, during the testing phase, the Company received $55,000 and $1.3 million of revenue from affiliates of Sempra and Reliant Resources, respectively. These amounts were recorded as a reduction of the Project's total construction costs.

The Company and certain affiliates of Sempra and Reliant Resources are parties to separate offtake and gas supply agreements which provide for the purchase of gas and the sale of electric energy attributable to the Company's available capacity based on either a month-ahead or day-ahead nomination. The electricity prices used in 2001 were based on the market clearing prices from the California Power Exchange through January 25, 2001. For the period from January 26, 2001 through June 30, 2001, the Company sold capacity and energy to

affiliates of the Members under the terms of the Amendment to the Credit Agreement discussed in Note 3. For the period January 26, 2001 through February 28, 2001, the Company received revenues from the affiliates equal to the cost of gas used in producing the electricity plus a fixed scheduling fee. For the period March 1, 2001 through June 30, 2001, the Company received revenues from the trading affiliates based on electricity prices derived from a natural gas index, applicable heat rate and operations and maintenance charges. The Members each contributed capital of $8.5 million in 2001 in order to maintain the required Cash Flow to Debt Service Ratio for the Waiver Period discussed in Note 3. From July 1, 2001 forward, under an amendment to the offtake and gas supply agreements, the Company is paid based on the Dow Jones SP15 index. In 2000, the prices as established by the California Power Exchange served as the basis of payment.

In 2002, 2001, and 2000, under these offtake and gas supply agreements, the Company recorded gross margin of $11.7 million, $16.4 million, and $66.2 million from an affiliate of Reliant Resources, respectively, and $11.7 million, $8.5 million, and $62.4 million from an affiliate of Sempra, respectively. At December 31, 2002, the Company had an estimated net receivable of $1.1 million from each of the affiliates of Sempra and Reliant Resources. The Company also paid each affiliate a monthly scheduling fee of $32,000.

The Company has purchased a $2.0 million surety bond securing its financial and performance obligations under the terms of the service agreement for transportation of customer secured natural gas. No draws were made under this bond in 2002, 2001, or 2000.

8. DERIVATIVE FINANCIAL INSTRUMENTS

(a) Risk Management Activities.

Effective January 1, 2001, the Company adopted SFAS No. 133, which establishes accounting and reporting standards for derivative instruments, including certain hedging instruments, embedded in other contracts and for hedging activities. This statement requires that 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 (loss), depending on the intended use of the derivative, its resulting designation and its effectiveness. If certain conditions are met, an entity may designate a derivative instrument as hedging (a) the exposure to changes in the fair value of an asset or liability, (b) the exposure to variability in future cash flows or (c) the foreign currency exposure of a net investment in a foreign operation. For a derivative not designated as a hedging instrument, the gain or loss is recognized in earnings in the period it occurs. The Company did not enter into any fair value or foreign exchange hedges in 2002 or 2001.

Adoption of SFAS No. 133 on January 1, 2001 resulted in a cumulative increase in accumulated other comprehensive income of approximately $2.1 million. The adoption also increased current assets and non-current assets by $0.7 million and $1.4 million, respectively. During the year ended December 31, 2001, $0.7 million of the initial transition adjustment in other comprehensive income was recognized in net loss.

The Company is exposed to various market risks. These risks are inherent in the Company's financial statements and arise from transactions entered into in the normal course of business. The Company uses interest rate swap agreements to mitigate the effect of changes in interest rates on the borrowings under the Credit Agreement discussed in Note 3.

(b) Non-Trading Activities.

Cash Flow Hedges. The Company applies hedge accounting for its derivative financial instrument used in non-trading activities only if there is a high correlation between price movements in the derivative and the item designated as being hedged. The correlation, a measure of hedge effectiveness, is assessed both at the inception

of the hedge and on an ongoing basis, with an acceptable level of correlation of at least 80% to 125% required for hedge designation. If and when correlation ceases to exist at an acceptable level, hedge accounting ceases and prospective changes in fair value are recognized currently in the Company's results of operations. During the years ended December 31, 2002 and 2001, the amount of hedge ineffectiveness recognized in earnings from derivatives that are considered cash flow hedges was $0.2 of loss and $0.2 million of gain, respectively. No component of derivative gain or loss was excluded from the assessment of effectiveness. When it becomes probable that an anticipated transaction will not occur, the Company realizes in net income the deferred gains or losses recognized in accumulated other comprehensive loss. During the year ended December 31, 2002 and 2001, there were no deferred gains or losses recognized as a result of the discontinuance of cash flow hedges where it was no longer probable that the forecasted transaction would occur. Once the forecasted transaction occurs, the accumulated deferred gain or loss recognized in accumulated other comprehensive loss is reclassified to net income and included in the Company's Statements of Operations under the caption interest expense in the case of interest rate swap transactions. As of December 31, 2002, the Company expects $4.0 million of accumulated comprehensive loss to be reclassified into net income during the next twelve months.

The maximum length of time the Company is hedging its exposure to payment of variable interest rates is two years.

The Company has entered into an interest rate swap agreement with a counterparty that fixes the interest rate applicable to the Company's floating rate debt (see Note 3). As of December 31, 2002, floating rate LIBOR-based interest payments are exchanged for fixed-rate interest payments of 5.34%. The notional amount of the interest rate swap agreement was $108.1 million and $112.5 million at December 31, 2002 and 2001, respectively.

9. EPC CONTRACT CLOSEOUT SETTLEMENT

Kiewit Industrial Company ("Kiewit") was the engineering, procurement and construction contractor for the Project. In December 2000, the Company drew on Kiewit's $19.9 million performance guarantee letter of credit because several issues remained unresolved with Kiewit related to the construction of the Project. The issues included performance shortfall and guarantee payments, late completion payments, delayed start up claims, completion of punchlist items, and outstanding warranty items.

In April 2001, in order to resolve EPC performance shortfall issues and remaining contract obligations with Kiewit, the Company entered into a Project Closeout Agreement with Kiewit and Siemens Westinghouse Power Corporation, the manufacturer of certain equipment at the Project. The agreement provides for the return of $18.2 million of the $19.9 million drawn on Kiewit's letter of credit in December 2000 upon successful completion of various modifications. During 2002 and 2001, the Company returned $6.3 million and $11.9 million to Kiewit, respectively. The Company will retain $1.7 million as compensation for Kiewit's remaining contract obligations, which has been recorded as a reduction of property, plant and equipment.

10. LONG-TERM POWER GENERATION MAINTENANCE AGREEMENT

On September 30, 2002, the Company entered into a long-term power generation maintenance agreement that covers certain periodic maintenance, including parts, on power generation turbines. The term of the agreement is based on turbine usage which the Company estimates would extend no longer than 12 years. The amount recognized in operations and maintenance expense under the terms of this agreement during 2002 was $2.9 million.

Payments under the agreement include fees for administration and management and a variable fee based on a charge for each hour the unit runs. The fee is also adjusted annually for escalation and may be adjusted based on the number of times a unit is started.

The payments are classified as prepayments on the balance sheet and are expensed as the services are provided. While some services are provided ratably throughout the year, the primary driver of the expense will be planned outages at the facility and are subject to fluctuations based on the timing and scope of the services being provided.

As of December 31, 2002, no payments have been made under the long-term maintenance agreements. Estimated cash payments over the five succeeding fiscal years are as follows (in millions):

2003	$ 8
2004	9
2005	7
2006	8
2007	8
Total	$40

11. POWER PURCHASE AGREEMENT

On December 18, 2002, the Company entered into a power purchase agreement with the City of Boulder City, Nevada (the "City") for the sale of up to 10 MW per year beginning on April 1, 2003 and terminating on March 31, 2023. The contract gives the City the option to purchase energy from the Company at a rate that is based on a fixed heat rate, variable natural gas price at the time of energy consumption, and a fixed margin. No revenues were earned in 2002 under this contract.

12. INSURANCE PROCEEDS

During 2002, the Company received proceeds for certain business interruption and property insurance claims for $37.4 million and $6.3 million, respectively. These proceeds relate to the steam turbine outage that occurred on March 13, 2001. The proceeds are classified as other income in the statements of operations.

13. COMMITMENTS AND CONTINGENCIES

The Company is involved in various claims and lawsuits regarding matters arising in the ordinary course of business. The Company believes that the effects on the financial statements, if any, from the disposition of these matters will not have a material adverse effect on the Company's financial condition, results of operations or cash flows.

ITEM 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

PART III

ITEM 10. ***Directors and Executive Officers.***

The information called for by Item 10, to the extent not set forth in "Executive Officers" in Item 1, will be set forth in the definitive proxy statement relating to our 2003 annual meeting of stockholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof called for by Item 10 are incorporated herein by reference pursuant to Instruction G to Form 10-K/A.

ITEM 11. ***Executive Compensation.***

The information called for by Item 11 will be set forth in the definitive proxy statement relating to our 2003 annual meeting of stockholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof called for by Item 11 are incorporated herein by reference pursuant to Instruction G to Form 10-K/A.

ITEM 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

The information called for by Item 12 will be set forth in the definitive proxy statement relating to our 2003 annual meeting of stockholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K/A.

ITEM 13. ***Certain Relationships and Related Transactions.***

The information called for by Item 12 will be set forth in the definitive proxy statement relating to our 2003 annual meeting of stockholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K/A.

ITEM 14. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures

Our chief executive officer and chief financial officer have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934) as of a date, the evaluation date, within 90 days prior to the filing date of our Form 10-K/A. Based on such evaluation, such officers have concluded that, as of the evaluation date, our disclosure controls and procedures are effective in alerting them on a timely basis to material information required to be included in our reports filed or submitted under the Securities Exchange Act of 1934.

Changes in Internal Controls

Since the evaluation date, there have not been any significant changes in our internal controls or in other factors that could significantly affect such controls.

PART IV

ITEM 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K.***

(a)(1) Reliant Resources, Inc. and Subsidiaries Financial Statements.

(a)(2) Financial Statement Schedules.

The following schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements: III, IV and V.

El Dorado Energy, LLC Financial Statements.

The following financial statements of our unconsolidated investment of El Dorado Energy, LLC are presented pursuant to Rule 3-09 of Regulation S-X.

(a)(3) Exhibits

See Index of Exhibits, which index also include the management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K/A by Item 601(b)(10)(iii) of Regulation S-K.

(b) Reports on Form 8-K.

- Current Report on Form 8-K dated September 30, 2002, as filed with the SEC on October 11, 2002 (Items 5 and 7).
- Current Report on Form 8-K dated October 29, 2002, as filed with the SEC on October 29, 2002 (Items 5, 7 and 9).
- Current Report on Form 8-K dated November 11, 2002, as filed with the SEC on November 12, 2002 (Items 5 and 7).
- Current Report on Form 8-K dated November 13, 2002, as filed with the SEC on November 21, 2002 (Items 5 and 7).
- Current Report on Form 8-K dated November 25, 2002, as filed with the SEC on November 25, 2002 (Items 7 and 9).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Amendment to Annual Report on Form 10-K/A to be signed on its behalf by the undersigned, thereunto duly authorized.

RELIANT RESOURCES, INC.
(Registrant)

By: /s/ JOEL V. STAFF

Joel V. Staff
Chairman and Chief Executive Officer
April 30, 2003

CERTIFICATIONS

I, Joel V. Staff, certify that:

1. I have reviewed this Annual Report on Form 10-K/A of Reliant Resources, Inc.;

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Annual Report;

4. The Registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Registrant and we have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;

   (b) evaluated the effectiveness of the Registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this Annual Report (the "Evaluation Date"); and

   (c) presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the Registrant's auditors and the audit committee of Registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Registrant's ability to record, process, summarize and report financial data and have identified for the Registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal controls; and

6. The Registrant's other certifying officers and I have indicated in this Annual Report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: April 30, 2003

/s/ JOEL V. STAFF

Joel V. Staff
Chairman and Chief Executive Officer

CERTIFICATIONS

I, Mark M. Jacobs, certify that:

1. I have reviewed this Annual Report on Form 10-K/A of Reliant Resources, Inc.;

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Annual Report;

4. The Registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Registrant and we have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;

   (b) evaluated the effectiveness of the Registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this Annual Report (the "Evaluation Date"); and

   (c) presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the Registrant's auditors and the audit committee of Registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Registrant's ability to record, process, summarize and report financial data and have identified for the Registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal controls; and

6. The Registrant's other certifying officers and I have indicated in this Annual Report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: April 30, 2003

/s/ MARK M. JACOBS

Mark M. Jacobs
Executive Vice President and Chief Financial Officer

ATTACHMENT 3

BALANCE SHEET,
PROJECTED INCOME STATEMENT,
AND STPEGS EXPENSE PROJECTIONS OF
TEXAS GENCO, LP
(NON-PROPRIETARY VERSION)

TEXAS GENCO
BALANCE SHEET
As of December 31, 2002
(In Millions)

ASSETS

Current Assets

Cash and Temporary Cash Investments	
Accounts Receivable	
Inventories	
Other Current Assets	
Total Current Assets	

Fixed Assets

Property, Plant & Equipment (net)	

Other Long Term Assets

Decommissioning Funds	
Goodwill	
Other Long Term Assets	
Total Other Assets	

Total Assets	

LIABILITIES

Current Liabilities

Accounts Payable	
Other Current Liabilities	
Total Current Liabilities	

Non-Current Liabilities

Deferred Tax Liabilities	
Nuclear Decommissioning Reserve	
Other Long Term Liabilities	
Total Non-Current Liabilities	

Capitalization

Debt	
Equity	
Total Capitalization	

Total Liabilities & Capitalization	

* source: Texas Genco Holdings 2002 10-K

TEXAS GENCO (STPEGS)
PROJECTED INCOME STATEMENT
(In Millions)

	2004	2005	2006	2007	2008
Power Sales Revenues					
Other Revenues					
Total Revenues					
Operating Expenses					
Fuel					
Operation & Maintenance					
Depreciation & Amortization					
Administrative & General					
Decommissioning Expense					
Taxes Other than Income					
Other					
Total Operating Expenses					
Operating Income (Loss)					
Other Income (Deductions)					
Income before Income Taxes					
Income Taxes					
Net Income (Loss)					

TEXAS GENCO (STPEGS)
PROJECTED INCOME STATEMENT
(in Millions)

	2004	*2005*	*2006*	*2007*	*2008*
Power Sales Revenues					
Net Capacity Factor (%)					
Net Generation (GWh)					
Average Price per MWh					
Operating Expenses					
Fuel					
Operation & Maintenance					
Depreciation & Amortization					
Administrative & General					
Decommissioning Expense					
Taxes Other than Income					
Other					
Total Operating Expenses					
Operating Income (Loss)					
Other Income (Deductions)					
Income before Income Taxes					
Income Taxes					
Net Income (Loss)					

STPEGS EXPENSE PROJECTIONS [1]
(in Millions)

	2004	2005	2006	2007	2008
Operating Expenses					
O&M (includes A&G [2])					
Fuel					
Taxes Other Than Income					
OTHER EXPENSES:					
Depreciation					
Property Taxes					
TOTAL					
Decommissioning [3]					

1 Texas Genco's 30.8% share of total STP projected expenses.
2 A&G reflects 1.1 FTEs (at the management and executive levels)
3 Decommissioning is handled as a pass through from the TDU from electric rates and does not affect the income statement

ATTACHMENT 4

10 CFR 2.790 AFFADAVIT OF DAVID G. TEES

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
STP Nuclear Operating Company	)	Docket Nos. 50-498
	)	50-499
South Texas Project Units 1 and 2	)	

AFFIDAVIT

I, David G. Tees, Manager and President of Texas Genco GP, LLC, which is the General Partner of Texas Genco, LP, do hereby affirm and state:

1. I am authorized to execute this affidavit on behalf of Texas Genco, LP.

2. Texas Genco, LP is providing information in support of its Application for Order Approving Indirect Transfer of Control of Licenses. The documents being provided in Attachment 3A contain financial projections related to the ownership and operation of Texas Genco, LP's generation assets, including the South Texas Project Electric Generating Station. These documents constitute proprietary commercial and financial information that should be held in confidence by the NRC pursuant to the policy reflected in 10 CFR §§ 2.790(a)(4) and 9.17(a)(4), because:

   i. This information is and has been held in confidence by Texas Genco, LP.

   ii. This information is of a type that is customarily held in confidence by Texas Genco, LP, and there is a rational basis for doing so because the information contains sensitive financial information concerning projected revenues and operating expenses of Texas Genco, LP.

   iii. This information is being transmitted to the NRC voluntarily and in confidence.

   iv. This information is not available in public sources and could not be gathered readily from other publicly available information.

   v. Public disclosure of this information would create substantial harm to the competitive position of Texas Genco, LP by disclosing its internal financial projections.

3. Accordingly, Texas Genco, LP requests that the designated documents be withheld from public disclosure pursuant to the policy reflected in 10 CFR §§ 2.790(a)(4) and 9.17(a)(4).

David G. Tees

STATE OF TEXAS)
COUNTY OF Harris)
)

Subscribed and sworn to me, a Notary Public, in and for the State of Texas, this 23rd day of September, 2003.

June M. Braden
Notary Public in and for the
State of Texas

JUNE M. BRADEN
Notary Public, State of Texas
My Commission Expires 4/18/2005

NOTARY PUBLIC STATE OF TEXAS