RELIANT RESOURCES INC
Form 10-K/A
July 05, 2002

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

FORM 10-K/A

AMENDMENT NO. 1

(MARK ONE)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2001

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-
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer I
1111 LOUISIANA HOUSTON, TEXAS 77002	(713)
(Address and zip code of principal executive offices)	(Registrant's telephone

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON
Common Stock, par value $.001 per share, and associated rights to purchase Series A Preferred Stock	New York Stock

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 [X] 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. [ ]

The aggregate market value of the voting stock held by non-affiliates of Reliant Resources, Inc. (Reliant Resources) was $833,436,412 as of April 1, 2002, 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 April 1, 2002, Reliant Resources had 289,354,781 shares of Common Stock outstanding including 240,000,000 shares which were held by Reliant Energy, Incorporated. Excluded from the number of shares of Common Stock outstanding are 10,449,219 shares held by Reliant Resources as treasury stock.

Portions of the definitive proxy statement relating to the 2002 Annual Meeting of Stockholders of Reliant Resources, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2001, 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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Reliant Resources, Inc. (Reliant Resources) hereby amends Items 1, 6, 7 and 8 of its Annual Report of Form 10-K for the year ended December 31, 2001 as originally filed on April 15, 2002.

Restatement

On May 9, 2002, Reliant Resources determined that it had engaged in same-day commodity trading transactions involving purchases and sales with the same counterparty for the same volume at substantially the same price, which the personnel who effected these transactions apparently did so with the sole objective of increasing volumes. Reliant Resources commenced a review to quantify the amount and assess the impact of these trades (round trip trades). The Audit Committees of each of the Board of Directors of Reliant Resources and Reliant Energy, Incorporated (Reliant Energy), a diversified international energy services and energy delivery company that owns approximately 83% of our outstanding common stock, also directed an internal investigation by outside legal counsel, with assistance by outside accountants, of the facts and circumstances relating to the round trip trades and related matters.

We currently report all trading, marketing and risk management services transactions on a gross basis with such transactions being reported in revenues and expenses except primarily for financial gas transactions such as swaps. Therefore, the round trip trades were reflected in both our revenues and expenses (i.e. they should have been reflected on a net basis). The round trip trades should not have been recognized in revenues or expenses. However, since the round trip trades were done at the same volume and substantially the same price, they had no impact on our reported cash flows, operating income or net income. In addition to the round trip trades reported on May 13, 2002, we also identified an additional transaction in 1999, which based on available information, Reliant Resources believes was also recorded with the sole objective of increasing volumes but also resulted in increased revenues and fuel and cost of gas sold expense.

In addition, during the May 2001 through September 2001 time frame, we entered into four structured transactions involving a series of forward or swap contracts to buy and sell an energy commodity in 2001 and to buy and sell an energy commodity in 2002 or 2003 (four structured transactions). The four structured transactions were intended to increase future cash flow and earnings and to increase certainty associated with future cash flow and earnings, albeit at the expense of 2001 cash flow and earnings. Each series of contracts in a structure were executed contemporaneously with the same counterparty and were for the same commodities, quantities and locations. The contracts in each structure were offsetting in terms of physical attributes. The transactions that settled in 2001 were previously recorded on a gross basis with such transactions being reported in revenues and expenses which resulted in $1.5 billion of revenues, $364 million in fuel and cost of gas sold and $1.2 billion of purchased power expense being recognized during the period from May 2001 through December 31, 2001. Having further reviewed the transactions, we now believe these transactions should have been accounted for on a net basis.

In the course of our review, we also identified and determined to record on a net basis several transactions for energy related services (not involving round trip trades) that totaled $85 million over the three year period ended December 31, 2001. These transactions were originally recorded on a gross basis.

During the fourth quarter of 2000, two power generation swap contracts with a fair value of $261 million were terminated and replaced with a substantially similar contract providing for physical delivery and designated to hedge electric generation. The termination of the original contracts and execution of the replacement contract represented a substantive modification to the original contract. As a result, upon termination of the original contracts, a contractual liability representing the fair value of the original contracts and a deferred asset of equal amount should have been recorded. As of January 1, 2001, in connection with the adoption of Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended, the deferred asset should have been recorded as a transition adjustment to other comprehensive loss. The liability and transition adjustment should have been amortized on a straight-line basis over the term of the power generation contract replacing the terminated power generation contracts (through May 2004). We previously did not give accounting recognition to these transactions. As a result, we have restated our Consolidated Balance Sheets as of December 31, 2000 and 2001 and the Statement of Consolidated Stockholders' Equity and Comprehensive Income for the year ended December 31, 2001, to appropriately account for these transactions as described above. The restatement had no impact on our reported consolidated cash flows, operating income or net income.

As a result, Reliant Resources' consolidated financial statements (Original Consolidated Financial Statements) and related disclosures for 1999, 2000 and 2001 have been restated from amounts previously reported. The principal effects of the restatement on the consolidated financial statements are set forth in Note 1 to our consolidated financial statements contained in this Form 10-K/A.

For purposes of this Form 10-K/A, and in accordance with Rule 12b-15 under the Securities Exchange Act of 1934, as amended, each item of the Form 10-K for the year ended December 31, 2001 as originally filed on April 15, 2002 that was affected by the restatement has been amended to the extent affected and restated in its entirety. 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 EXCEPT AS REQUIRED TO REFLECT THE EFFECTS OF THE RESTATEMENT.

We are a party to numerous lawsuits and regulatory proceedings relating to our trading and marketing activities, including the round trip trades and the four structured transactions, and our activities in the California wholesale market. In addition, various state and federal governmental agencies have commenced investigations relating to such activities. For a description of certain of these lawsuits, proceedings and investigations, please read "Legal Proceedings" in Item 3 of this Form 10-K and Notes 13(e) and 13(i) to our consolidated financial statements, Notes 11 and 14(c) to our interim financial statements included in our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002 (First Quarter Form 10-Q), and our Current Report on Form 8-K dated July 3, 2002.

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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. In some cases, 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," or other similar words.

For a list of factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings" in Item 7 of this Form 10-K.

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 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.

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.

The following sections of this Form 10-K contain forward-looking statements:

- Our Business -
  - General
  - Formation, Initial Public Offering and Anticipated Distribution
- Wholesale Energy -
  - Northeast Region -
    - Facilities
  - Midwest Region -
    - Facilities
  - Florida and Other Southeastern Markets -

- Results of Operations by Business Segment -
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        - 2001 Compared to 2000
        - Related-Party Transactions -
            - Agreements Between Reliant Energy and Reliant Resources -
                - Service Agreements
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- Certain Factors Affecting Our Future Earnings -
    - Factors Affecting the Results of Our Wholesale Energy Operations -
        - Price Volatility
        - Risk Associated with Our Hedging and Risk Management Activities
        - Uncertainty in the California Market
        - Industry Restructuring, the Risk of Re-regulation and the Impact of Current Regulations
        - Uncertainty Related to the New York Regulatory Environment
        - Integration and Other Risks Associated with Our Orion Power Assets
        - Operating Risks
        - Factors Affecting Our Acquisition and Project Development Activities
        - Increasing Competition in Our Industry
        - Hydroelectric Facilities Licensing
    - Factors Affecting the Results of Our European Energy Operations -
        - General
        - Competition in the European Market

ITEM 1. BUSINESS.

OUR BUSINESS

GENERAL

Reliant Resources, Inc., a Delaware corporation, was incorporated in August 2000. In this Form 10-K, we refer to Reliant Resources, Inc. as "Reliant Resources," and to Reliant Resources and its subsidiaries collectively, as "we" or "us," unless the context clearly indicates otherwise. The executive offices of Reliant Resources are located at 1111 Louisiana, Houston, TX 77002 (telephone number 713-207-3000).

We provide electricity and energy services with a focus on the competitive wholesale and retail segments of the electric power industry in the United States. We acquire, develop and operate electric power generation facilities that are not subject to traditional cost-based regulation and therefore can generally sell power at prices determined by the market. We also trade and market power, natural gas and other energy-related commodities and provide related risk management services.

As of December 31, 2001, we owned or leased electric power generation facilities with an aggregate net generating capacity of 14,585 megawatts (MW), including 11,109 MW in the United States and 3,476 MW in the Netherlands. Of the 11,109 MW in the United States, 1,179 MW represent our entitlement to capacity of facilities that we lease under operating leases. For additional information regarding these operating leases, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Consolidated Capital Requirements and Uses of Cash" in Item 7 of this Form 10-K, and Note 13(c) to our consolidated financial statements, which, together with the notes related to these statements, we refer to in this Form 10-K as our "consolidated financial statements." We acquired our first power generation facilities in 1998 and have increased our net generating capacity since then through a combination of acquisitions and development of new generation projects. Since December 31, 2001, we have added 5,644 MW of additional net generating capacity to our asset portfolio through our acquisition of Orion Power Holdings, Inc. According to Resource Data International, Inc., we are the second largest independent electric power producer in the United States based on total MW of wholesale generation capacity in operation as of February 28, 2002.

As of December 31, 2001, we had 3,587 MW (3,391 MW, net of 196 MW to be retired upon completion of one facility) of additional net generating capacity under construction, including 2,120 MW of facilities owned by off-balance sheet special purpose entities that are being constructed under construction agency agreements pursuant to synthetic leasing arrangements. Upon the completion of construction, we expect that we will lease these facilities from their owners. For additional information regarding the construction agency agreements, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Off-Balance Sheet Transactions" in Item 7 of this Form 10-K and Note 13(h) to our consolidated financial statements. 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.

Additionally, we became a retail electric provider (i.e., a seller of electricity to retail customers) in Texas when that market began opening to retail electric competition in late 2001 and fully opened to retail competition in January 2002. Since then, all classes of customers of most investor-owned Texas utilities, as well as those of any municipal utility or electric cooperative that opted to participate in the competitive marketplace, have been able to choose their retail electric provider. Under Texas regulation, retail electric providers procure or buy electricity from wholesale generators at unregulated rates, sell electricity at generally unregulated rates to their retail customers and pay the local transmission and distribution regulated utilities a regulated tariff rate for delivering the electricity to their customers. In January 2002, we became the retail electric provider for all of Reliant Energy HL&P's (formerly the integrated electric utility serving the Houston, Texas metropolitan area) (Reliant Energy's electric utility) approximately 1.7 million customers in the Houston area who did not take action to select another retail electric provider. At that time, we were also able to acquire and serve new retail electric customers in other Texas competitive markets.

We conduct our operations through the following business segments:

- Wholesale Energy - provides electricity and energy services in the competitive segments of the United States wholesale energy industries,
- European Energy - includes power generation assets in the Netherlands and a related trading and power origination business,
- Retail Energy - provides electricity and related services to retail customers primarily in Texas, and
- Other Operations - includes the operations of our venture capital and Communications businesses, and unallocated corporate costs.

For information about the revenues, operating income, assets and other financial information relating to our business segments, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations by Business Segment" in Item 7 of this Form 10-K and Note 18 to our consolidated financial statements. For information regarding the decision to exit our Communications business, please read Note 16 to our consolidated financial statements.

FORMATION, INITIAL PUBLIC OFFERING AND ANTICIPATED DISTRIBUTION

Reliant Energy, Incorporated (Reliant Energy) owns more than 80% of our outstanding common stock. Reliant Energy has 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 (Texas Utility Commission), Reliant Energy has transferred substantially all of its unregulated businesses to us in order to separate its regulated and unregulated operations. In accordance with the plan, we completed our initial public offering (IPO) of nearly 20% of our common stock in May 2001 and received net proceeds from the IPO of $1.7 billion. Pursuant to the terms of the master separation agreement between Reliant Energy and us, we used $147 million of the net proceeds to repay certain indebtedness owed to Reliant Energy. We used the remainder of the net proceeds of the IPO for repayment of third party borrowings, capital expenditures, repurchases of our common stock and to increase our working capital. For additional information regarding the IPO, please read Notes 1 and 9(a) to our consolidated financial statements. For additional information regarding agreements and transactions between Reliant Resources and Reliant Energy, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Related-Party Transactions" in Item 7 of this Form 10-K and Notes 3 and 4 to our consolidated financial statements.

As part of its business separation plan, Reliant Energy has publicly disclosed that it intends to restructure its corporate organization into a public utility holding company structure (Reorganization) and to distribute, subject to further governmental and corporate approvals, market and other conditions, its remaining equity interest in our common stock to its or its successor's shareholders (Distribution). In December 2001, Reliant Energy's shareholders voted to approve the merger required for the holding company reorganization. As a result of the Reorganization and the Distribution, Reliant Energy's successor holding company will be named "CenterPoint Energy, Inc." and will own essentially all of Reliant Energy's regulated businesses (CenterPoint Energy), and we will become a separate company unaffiliated with CenterPoint Energy. Reliant Energy has publicly disclosed its goal to complete the Reorganization and subsequent Distribution as quickly as possible after all the necessary conditions are fulfilled, including receipt of an order from the Securities and Exchange Commission (SEC) granting the required approvals under the Public Utility Holding Company Act of 1935 (1935 Act) and an extension from the IRS for a private letter ruling obtained by Reliant Energy regarding tax-free treatment of the Distribution. Reliant Energy has filed an application with the SEC requesting the required approvals. The IRS private letter ruling is predicated on the completion of the Distribution by April 30, 2002. Reliant Energy is in the process of requesting an extension of this deadline. Reliant Energy currently expects to complete the Reorganization and Distribution in the summer of 2002. We cannot assure you that the Distribution will be completed as described or within the time period outlined above.

ORION POWER ACQUISITION

On February 19, 2002, we acquired all of the outstanding shares of common stock of Orion Power Holdings, Inc. (Orion Power) for $26.80 per share in cash pursuant to a definitive merger agreement for an aggregate purchase price of $2.9 billion. At the time of closing, Orion Power had approximately $2.4 billion of debt obligations ($2.1 billion net of cash acquired, some of which is restricted pursuant to debt covenants). Orion Power is an independent electric power generating company that was formed in March 1998 to acquire, develop, own and operate power generating facilities in certain deregulated wholesale markets in North America. Orion Power has 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 28, 2002, Orion Power owned 81 power plants with an aggregate net generating capacity of 5,644 MW and had two development projects with an additional 804 MW of capacity under construction. We consider most of the Orion Power facilities to be part of our Northeast regional portfolio and the remainder to be part of our Midwest regional portfolio. For additional information regarding our acquisition of Orion Power and its operations, please read " - Wholesale Energy - Northeast Region," and " - Midwest Region," and "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Integration and Other Risks Associated with Our Orion Power Assets" and " - Uncertainty Related to the New York Regulatory Environment" in Item 7 of this Form 10-K, and Note 19 to our consolidated financial statements.

WHOLESALE ENERGY

Our Wholesale Energy business segment provides energy and energy services with a focus on the competitive wholesale segment of the United States energy industry. We acquire, develop and operate electric power generation facilities that are not subject to traditional cost-based regulation and therefore can generally sell power at prices determined by the market, subject to regulatory limitations in certain regions. We also trade and market power, natural gas, natural gas transportation capacity and other energy-related commodities and provide related risk management services.

POWER GENERATION OPERATIONS

As of December 31, 2001, our Wholesale Energy business segment owned or leased electric power generation facilities with an aggregate net generating capacity of 11,109 MW located in five regions of the United States. We also had 3,587 MW (3,391 MW, net of 196 MW to be retired upon completion of one facility) of net generating capacity under construction as of that date. In addition, by acquiring Orion Power in February 2002, we added 81 power plants with an aggregate net generating capacity of 5,644 MW and two development projects with an additional 804 MW of capacity under construction to our regional portfolios.

The following table describes our Wholesale Energy business segment's electric power generation facilities by region as of December 31, 2001.

REGIONAL SUMMARY OF OUR GENERATION FACILITIES
(AS OF DECEMBER 31, 2001)

REGION	NUMBER OF GENERATION FACILITIES(1)	TOTAL NET GENERATING CAPACITY(MW)	DISPATCH TYPE(2)
NORTHEAST			
Operating(3)	21	4,262	Base, Inter, Peak
Under Construction(4)(5)(6)	1	1,120	Base, Inter, Peak
Combined	22	5,382	
MIDWEST			
Operating	2	1,063	Peak
Under Construction(7)	--	154	Peak
Combined	2	1,217	
SOUTHEAST			
Operating(8)	3	979	Inter, Peak, CoGen
Under Construction(5)(9)	1	958	Base, Inter, Peak
Combined	4	1,937	
WEST			
Operating(7)	7	4,635	Base, Inter, Peak
Under Construction	1	548	Base, Peak
Combined	8	5,183	
ERCOT(10)			
Operating	1	170	Base, CoGen

Under Construction(4)	--	611	Base, CoGen
Combined	1	781	
TOTAL			
Operating	34	11,109	
Under Construction	3	3,391	
Combined	37	14,500	

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

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

(3) We lease a 100%, 16.67% and 16.45% interest in three Pennsylvania facilities having 613 MW, 285 MW and 281 MW, respectively, through facility lease agreements having terms of 26.5 years, 33.75 years and 33.75 years, respectively.

(4) One of our two construction projects in this region will replace one of our existing facilities upon completion. Therefore, this project is not included in the facility count for the "Under Construction" group of this region.

(5) Our two construction projects in the Northeast region and one of our projects in the Southeast region are owned by off-balance sheet special purpose entities and are being constructed under construction agency agreements pursuant to synthetic leasing arrangements. We expect that we will lease these facilities from their owners upon completion.

(6) The 1,120 MW of net capacity under construction is based on 1,316 MW of capacity currently under construction less 196 MW of operating capacity that will be retired upon completion of one of the projects.

(7) Five of the six generating units of one of the facilities in this region are operational while the sixth unit is under construction. This partially operational facility is included in the facility count for the "Operating" group of this region.

(8) We own a 50% interest in one of these facilities. An independent third party owns the other 50%.

(9) Two of the three generating units of one of the facilities in this region are operational while the third unit is under construction. This partially operational facility is included in the facility count for the "Operating" group of this region.

(10) We also have an option, which is exercisable in January 2004, subject to completion of the Distribution, to acquire Reliant Energy's approximate 80% interest in a company that is currently expected to own approximately 13,900 MW of net generating capacity in the Electric Reliability Council of

Texas (ERCOT) in January 2004. For additional information regarding this option, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Related-Party Transactions - Agreements between Reliant Energy and Reliant Resources - Genco Option Agreement" in Item 7 of this Form 10-K and Note 4(b) to our consolidated financial statements.

The following table describes our Orion Power electric power generation facilities by region as of February 28, 2002.

REGIONAL SUMMARY OF OUR ORION POWER FACILITIES
(AS OF FEBRUARY 28, 2002)

REGION	NUMBER OF GENERATION FACILITIES	TOTAL NET GENERATING CAPACITY (MW)	DISPATCH TYPE(1)	
NORTHEAST				
Operating(2)	78	4,174	Base, Inter, Peak	Gas/
Under Construction	2	804	Base, Inter	Gas
Combined	80	4,978		
MIDWEST				
Operating	3	1,470	Base, Inter, Peak	Coal
TOTAL				
Operating(2)	81	5,644		
Under Construction	2	804		
Combined(2)	83	6,448		

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

(2) Two hydro plants with a net generating capacity of approximately 5 MW are not currently operational.

NORTHEAST REGION

Facilities. As of December 31, 2001, we owned or leased 21 electric power generation facilities with an aggregate net generating capacity of 4,262 MW located in the control area of PJM Interconnection, L.L.C. (PJM ISO), the independent system operator in the Pennsylvania-New Jersey-Maryland market (PJM market). These facilities are owned or leased by subsidiaries of one of our wholly owned subsidiaries, Reliant Energy Mid-Atlantic Power Holdings, LLC (REMA). The generating capacity of these facilities consists of approximately 40% of base-load, 40% of intermediate and 20% of peaking capacity, and represents approximately 7% of the total generation capacity located in the PJM ISO's control area. For additional information regarding our acquisition of these facilities, please read Note 5(a) to our consolidated financial statements.

By acquiring Orion Power in February 2002, we added 78 power generation facilities, of which 75 are currently operational, with an aggregate net generating capacity of 4,174 MW to our Northeast regional portfolio. These facilities include 70 hydroelectric facilities, of which 68 are currently operational, located in central and northern New York State, three facilities located in New York City, one facility located in East Syracuse, New York, and four facilities, three of which are currently fully operational, located in Pennsylvania. The generating capacity of these facilities consists of approximately 45% of base-load, 35% of intermediate and 20% of peaking capacity. For a discussion of factors that may affect the future earnings generated by these Orion Power facilities, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Integration and Other Risks Associated With Our Orion Power Assets" and " - Uncertainty Related to the New York Regulatory Environment" in Item 7 of this Form 10-K.

We have begun construction on a 795 MW gas-fired base-load and intermediate facility located in Pennsylvania. We expect this facility will begin commercial operation in the second quarter of 2003. We have also begun construction on a 521 MW coal-fired base-load facility, also located in Pennsylvania, that will replace one of our existing facilities. This facility will add 325 MW of additional capacity to our Northeast regional portfolio, net of the 196 MW of capacity of the currently existing facility that will be retired upon commencement of commercial operations of the new facility. We expect this facility will begin commercial operation near the end of 2004. These facilities are owned by off-balance sheet special purpose entities and are being constructed under the terms of separate construction agency agreements pursuant to synthetic leasing arrangements. Upon completion of the construction of these facilities, we expect that we will lease these facilities from their owners, purchase or remarket each facility. For additional information regarding the construction agency agreements, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Off-Balance Sheet Transactions - Construction Agency Agreements" in Item 7 of this Form 10-K and Note 13(h) to our consolidated financial statements.

By acquiring Orion Power in February 2002, we added two additional development projects with an additional 804 MW of capacity under construction. The first project is the construction of a 550 MW gas-fired base-load facility located south of Philadelphia, Pennsylvania. We expect this facility will begin commercial operation in the second quarter of 2002. The second project is the conversion and upgrade of a peaking facility located near downtown Pittsburgh, Pennsylvania. We expect this project will be completed by the third quarter of 2002 and will increase the aggregate generating capacity of this facility by 254 MW to a total capacity of 308 MW.

Market Framework. We currently sell the power generated by our Northeast regional facilities in the PJM market, the wholesale energy market of the State of New York (New York wholesale market) operated by the New York Independent System Operator (NYISO) and to buyers in adjacent power markets, such as the region covered by the East Central Area Reliability Coordinating Counsel (ECAR market). We also expect to sell power in a newly created extension of the PJM market in western Pennsylvania (PJM West market). Each of the PJM Market, the New York wholesale market and the PJM West market operate as centralized power pools with open-access, non-discriminatory transmission systems administered by independent system operators approved by the Federal Energy Regulatory Commission (FERC). 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 eastern Pennsylvania to western Pennsylvania and into New York City may be constrained from time to time. 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. For example, as a result of transmission constraints into New York City, power prices are generally higher there than in other parts of the state.

In addition to managing the transmission system for each market, the respective independent system operator for each of the PJM market, the New York wholesale market and the PJM West market is responsible for maintaining competitive wholesale markets, operating the spot wholesale energy market and determining the market clearing price based on bids submitted by participating generators in each market. Each independent system operator generally matches sellers with buyers within a particular market that meet specified minimum credit standards. We sell capacity, energy and ancillary services into the markets maintained by the applicable independent system operator for each of these types of products for both real-time sales and forward sales for periods of up to one year. Our customers include the members of each market, consisting of municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities, retail electric providers and power marketers. We also sell capacity, energy and ancillary services to customers in the Northeast region under negotiated bilateral contracts. Bilateral contracts, in addition to other physical and financial transactions enable us to hedge a portion of our generation portfolio. For a more complete description of our hedging strategy and a summary of the consolidated hedge position of our United States generating assets, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K.

Our markets in the Northeast region are subject to constant and significant regulatory oversight and control and the results of our operations in the region may be adversely affected by any changes or additions to the current regulatory structure. Our sales into markets administered by the PJM ISO are governed by the PJM ISO's operating

agreements, tariffs and protocols (PJM Protocols). The PJM Protocols provide the structure, rules and pricing mechanisms for the PJM ISO's energy, capacity and ancillary services markets, and establish rates, terms and conditions for transmission service in the PJM ISO's control area and the PJM West market, including transmission congestion pricing. Wholesale energy prices in the markets administered by the PJM ISO are currently capped at $1,000 per megawatt hour. Lower caps are utilized in other regions and it is possible that this price cap might be lowered in the future.

Our sales into markets administered by the NYISO are governed by the NYISO's tariff and protocols (NYISO Protocols). The NYISO Protocols provide the structure, rules and pricing mechanisms for the NYISO's energy, capacity and ancillary services markets, and establish rates, terms and conditions for transmission service in the NYISO's control area. The NYISO Protocols allow energy demand, commonly referred to as "load," to respond to high prices in emergency and non-emergency situations. The lack of programs, however, to implement load response 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 megawatt hour. Lower price caps are utilized in other regions and it is possible that this price cap might be lowered in the future.

A capacity market has been established by the NYISO that ensures 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 extra 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 New York City is currently short of this capacity requirement and the existing capacity is owned by only a few entities, a price cap has been instituted for in-city generators.

For additional discussion of the impact of current regulations on the markets in the Northeast region and the related risks of re-regulation, please read " - Regulation - Federal Energy Regulatory Commission" and "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Industry Restructuring, the Risk of Re-regulation and the Impact of Current Regulations" and " - Uncertainty Related to the New York Regulatory Environment" in Item 7 of this Form 10-K.

MIDWEST REGION

Facilities. As of December 31, 2001, we owned two electric power generation facilities located in the State of Illinois with an aggregate net generating capacity of 1,063 MW in operation. One of these facilities is a 344 MW gas-fired peaking generation facility located in Shelby County, Illinois. The first phase of this facility was initially placed in commercial operation in June 2000 and the second phase was placed in commercial operation in May 2001. We also have an 873 MW gas-fired peaking generation facility under construction in Aurora, Illinois. As of December 31, 2001, five of the six generating units at this facility with an aggregate net generating capacity of 719 MW had been placed in commercial operation. We expect the remaining unit at this facility will begin commercial operation in the second quarter of 2002.

By acquiring Orion Power in February 2002, we added three power generation facilities with an aggregate net generating capacity of 1,470 MW to our Midwest regional portfolio. Two of these facilities are located in Ohio and one is located in West Virginia. The generating capacity of these facilities consists of approximately 50% of base-load, 15% of intermediate and 35% of peaking capacity. For a discussion of the factors that may affect the future earnings generated by these Orion Power assets, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Integration and Other Risks Associated With Our Orion Power Assets" in Item 7 of this Form 10-K.

Market Framework. We sell the power generated by our Midwest regional facilities into the ECAR market and the region covered by the Mid-America Interconnected Network Reliability Council (MAIN market). These markets include all or portions of the states of Illinois, Wisconsin, Missouri, Indiana, Ohio, Michigan, Virginia, West Virginia, Tennessee, Maryland and Pennsylvania. These markets are currently in a state of transition and are in the process of establishing regional transmission organizations (RTO) that would define the rules and requirements around which competitive wholesale markets in the region would develop. The FERC has approved proposals by the Midwest Independent System Operator (Midwest ISO) to administer a substantial portion of the transmission facilities in the Midwest region. The FERC also has ordered the Alliance RTO, which had a separate proposal to be the RTO for parts of the Midwest region, to explore joining the Midwest ISO. As a result, the final market structure for the Midwest region remains unsettled. The timing of the development of a RTO and the extent to which the Midwest ISO and the Alliance RTO would combine is currently unknown. In addition, some states within these markets have restructured their electric power markets to competitive markets from traditional utility monopoly markets, while others have not. Currently the transmission infrastructure in these markets is generally owned by non-independent market participants, some of which are our competitors, which has the potential to create market anomalies. Transmission constraints exist in these markets and have been managed by the owners of the transmission infrastructure, subject to transmission tariffs and protocols regulated by the FERC.

We currently sell power from our facilities in the Midwest region to customers under bilateral contracts that are generally non-standard with highly negotiated terms and conditions. Our customers include municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities and power marketers. Direct customer sales, in addition to other physical and financial transactions enable us to hedge a portion of our generation portfolio. For a more complete description of our hedging strategy and a summary of the consolidated hedge position of our United States generating assets, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K.

FLORIDA AND OTHER SOUTHEASTERN MARKETS

Facilities. As of December 31, 2001, we owned, or owned interests in, three power generation facilities with an aggregate net generating capacity of 979 MW located in the states of Florida and Texas. These facilities include one gas and oil-fired generation facility with an aggregate net generating capacity of 619 MW located near Titusville, Florida. This facility can be operated as either an intermediate or a peaking facility. We also own a 464 MW gas and oil-fired peaking generation facility in Osceola County, Florida. Two of the three generating units of this plant with an aggregate net generating capacity of 310 MW commenced commercial operation in December 2001. We expect the remaining generating unit at this facility will begin commercial operation in the second quarter of 2002. In addition, we own a 50% interest in a 100 MW gas-fired base-load/cogeneration facility located in Orange, Texas. Air Liquide owns the other 50% interest in this plant which has been in commercial operation since December 1999.

We have begun construction on an 804 MW gas-fired intermediate/peaking facility in Choctaw County, Mississippi. We expect this facility will begin commercial operation in the second quarter of 2003. This facility is being constructed under the terms of a construction agency agreement under a synthetic leasing arrangement. Upon completion of the construction of this facility, we will have the right to lease, purchase or remarket the facility. For additional information regarding the construction agency agreement, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Off-Balance Sheet Transactions - Construction Agency Agreements" in Item 7 of this Form 10-K, and Note 13(h) to our consolidated financial statements.

Market Framework. We currently conduct the majority of our Southeast regional operations in the state of Florida. The state of Florida, other than a portion of the western panhandle, constitutes a single reliability council and contains approximately 5% of the United States population. The transmission-owning utilities in Florida have proposed establishing an independent system operator to assume control of the transmission system and undertake to define the rules and requirements for a competitive wholesale market. The timing of the development of an independent system operator for the Florida market is currently unknown. Under its present structure, the Florida market is dominated by incumbent utilities. There are a number of statutory and regulatory restrictions that negatively impact the development of additional power generation facilities in the region.

We currently sell power from our facilities in the Florida market under bilateral contracts that are non-standard and highly negotiated for terms and conditions. Until the rules for system operations are established, we expect limited trading opportunities will exist in the Florida market. The customers who participate in power transactions

in this region include municipalities, electric cooperatives and integrated utilities. We sell capacity and energy to customers in the Florida market, however a market for ancillary services has not developed. Forward hedging of a portion of our Florida portfolio is generally accomplished through customer-tailored, multi-year sale agreements as no liquid, over-the-counter or auction markets currently exists in Florida. For a more complete description of our hedging strategy and a summary of the consolidated hedge position of our United States generation assets, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K.

With respect to our facilities in East Texas and Mississippi, several of the transmission-owning utilities in the Southeast region have formed the SETrans Grid Company (SETrans RTO) that they are proposing to serve as the region's RTO. The proposed SETrans RTO would manage, but not own, the transmission grid in the region and operate forward and spot markets for energy. The SETrans RTO has filed a status report with the FERC, but has not filed tariffs or protocols and has not been approved as the region's RTO.

WEST REGION

Facilities. As of December 31, 2001, we owned, or owned interests in, seven electric power generation facilities with an aggregate net generating capacity of 4,635 MW located in the states of California, Nevada and Arizona. These facilities include approximately 20% of base-load, 75% of intermediate and 5% of peaking capacity. Our facilities in the West region include five facilities with an aggregate net generating capacity of 3,800 MW located in California. We also own a 50% interest in a 490 MW gas-fired, base-load, peaking facility located near Las Vegas, Nevada. Sempra Energy owns the other 50% interest in this plant. In addition, we own a 590 MW gas-fired, base-load, peaking generation facility in Casa Grande, Arizona. This facility was placed in commercial operation in the fourth quarter of 2001. We also have a 548 MW gas-fired, base-load, peaking generation facility under construction in 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 power generated by our California and Nevada facilities to customers located in the Los Angeles basin of southern California. We also sell power generated by our Nevada facility to customers located in southern Nevada. Our customers in these states include power marketers, investor-owned utilities, electric cooperatives, municipal utilities and the California Independent System Operator (Cal ISO) acting on behalf of load-serving entities. We sell power 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 market for capacity; however, a capacity market has recently been proposed by the Cal ISO under its market mitigation plan for the California market.

We have agreed to sell up to 100% of the power generated by our Arizona facility to the Salt River Project Agricultural Improvement and Power District of the State of Arizona under a long-term power purchase agreement. Bilateral contracts, in addition to other physical and financial transactions enable us to hedge a portion of our generation portfolio. For a more complete description of our hedging strategy and a summary of the consolidated hedge position of our United States generating assets, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K. In addition, although we do not own generation facilities in the states of Oregon, New Mexico, Utah and Washington, our trading and marketing operations purchase and deliver energy commodities in these states.

Our operations in the California market are subject to numerous environmental and other regulatory restrictions. Permits issued by local air districts restrict the output of some of our generating facilities. In addition, certain air districts require us to purchase emission credits to offset Nitrogen Oxides (NOx) emissions from our facilities.

In response to California's electricity market restructuring initiative, the FERC issued a series of orders in 1996 and 1997 approving a wholesale market structure administered by two independent non-profit corporations: the Cal ISO, responsible for operational control of the transmission system and the purchase or sale of electricity in "real-

time" to balance actual supply and demand, and the California Power Exchange (Cal PX), responsible for conducting auctions for the purchase or sale of electricity on a day-ahead or day-of basis. As part of this market restructuring, California's distribution utilities sold essentially all of their gas-fired plants to third-party generators. The utilities were required to sell their remaining generation into the Cal PX markets and purchase all of their power requirements from the Cal PX markets at market-based rates approved by the FERC. California's regulatory system initially prohibited the utilities from entering into forward contracts to cover the bulk of their customers' requirements. Retail electricity rates were initially frozen at levels in effect on June 10, 1996, with a 10% rate reduction for residential and smaller commercial customers. When wholesale power costs began to rise dramatically in 2000, driven by a combination of factors, including higher natural gas prices and emission allowance costs, reduction in available hydroelectric generation resources, increased demand and decreases in net imports, some of the California utilities were unable to recover their purchased power costs through the retail rates they were allowed to charge. As a result, the utilities accumulated huge debts to wholesale power suppliers, including us. The Cal ISO currently is conducting a major market redesign process that, if approved by the FERC, could change the structure of the markets operated by the Cal ISO, including changes to market monitoring and mitigation, congestion management and capacity obligations. For a discussion of litigation and other legal proceedings related to energy sales in California, the impact of current regulations on our West region and related uncertainty associated with the California wholesale market, please read " - Regulation - Federal Energy Regulatory Commission," "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Uncertainty in the California Market" and Notes 13(e) and 13(i) to our consolidated financial statements.

In Nevada and Arizona, there is presently no RTO in place to manage the transmission systems or to operate energy markets, although one RTO working group is evaluating the establishment of an organization that would assume control, subject to FERC approval, over the transmission systems of the utilities operating in this region. The FERC has recently expressed its intention to pursue the establishment of an RTO in the West region.

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. Similarly, in Arizona, proceedings are pending before the Arizona Corporation Commission that would allow the Arizona Public Service Company to avoid a requirement to seek competitive bids for 50% of the Arizona Public Service Company's generation needs.

ERCOT REGION

Facilities. We currently own a partially operational 781 MW gas-fired, combined cycle, cogeneration facility in Channelview, Texas. 170 MW of this facility's capacity is currently operational and 611 MW are under construction. We expect the remaining generating units for this facility will begin commercial operations in the third quarter of 2002.

In addition to our Channelview facility, we have an option exercisable in January 2004, subject to completion of the Distribution, to acquire Reliant Energy's ownership interest in a company (Texas Genco) that is currently expected to own approximately 13,900 MW of aggregate net generation capacity in Texas in January 2004 (Texas Genco Option). Reliant Energy has agreed to publicly offer or distribute to its shareholders approximately 20% of the common stock of Texas Genco before December 31, 2002. The generating capacity of these 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. As part of Reliant Energy's business separation plan, Reliant Energy's electric utility will convey its generating assets to Texas Genco. The conveyance is part of the anticipated restructuring of Reliant Energy's businesses into a holding company structure. For additional information regarding the Texas Genco Option, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Related Party Transactions - Agreements between Reliant Energy and Reliant Resources - Genco Option Agreement" in Item 7 of this Form 10-K, and Note 4(b) to our consolidated financial statements.

Market Framework. The state of Texas, other than a portion of the panhandle and a portion of the east bordering on Louisiana, constitutes a single reliability council (ERCOT market). As part of the transition to deregulation in Texas, ERCOT changed its operations from 10 control areas, managed by utilities in the state, to a single control area on July 31, 2001. 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 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 market. Unlike independent systems operators in other regions of the country, ERCOT is not a centrally dispatched pool and the ERCOT ISO 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. ERCOT also serves as agent for procuring ancillary services for those who elect not to provide 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 market operates under the reliability standards set by the North American Electric Reliability Council. The Texas Utility Commission has primary jurisdictional authority over the ERCOT market to ensure the adequacy and reliability of electricity across the state's main interconnected power grid. For information regarding ERCOT systems issues and delays, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Retail Energy Operations - Operational Risks" in Item 7 of this Form 10-K.

As part of the change to a single control area, ERCOT initially established three congestion zones; north, west and south. ERCOT will perform an annual analysis of the transmission capability in ERCOT to determine if changes to the congestions zones is required. Any required changes will take effect January 1 of the following year. Such an analysis was performed in the fall of 2001 and as a result, ERCOT was divided into four congestion zones on January 1, 2002. The current zones are north, south, west and Houston. In addition, ERCOT conducts annual and monthly auctions of Transmission Congestion Rights (TCR) which provide the entity owning TCRs the ability to financially hedge price differences between zones (basis risk). Entities are currently limited to owning a maximum of 25% of the available TCRs. The retail load obligation of our Retail Energy segment that was acquired as part of full retail deregulation on January 1, 2002 is predominately in the Houston zone. For additional information regarding the retail load obligations of our Retail Energy segment, please read " - 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 power, 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, please read Notes 6, 13(a) and 13(c) to our consolidated financial statements. For information regarding our hedging strategy relating to such long-term commitments, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K.

DEVELOPMENT ACTIVITIES

As of December 31, 2001, we had 3,587 MW (3,391 MW, net of 196 MW to be retired upon completion of one facility) of additional net generating capacity under construction, including 2,120 MW of facilities owned by off-balance sheet special purpose entities, that are being constructed under construction agency agreements pursuant to synthetic leasing arrangements. Upon the completion of the construction of these facilities, we expect that we will lease these facilities from their owners. For additional information regarding the construction agency agreements, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Off-Balance Sheet Transactions - Construction Agency Agreements" in Item 7 of this Form 10-K and Note 13(h) to our consolidated financial statements.

In addition, Orion Power had three projects totaling 1,054 MW under construction as of December 31, 2001. However, at this time, we have decided to postpone a 250 MW project in Florida because of capital market and economic considerations. With improved capital market conditions and required approvals from Florida authorities

on a newly configured 500 MW design, we would plan to proceed with construction in the future. Also, Orion Power had two projects under advanced development as of December 31, 2001, which have been deferred. A 1,088 MW project in Maryland has been postponed due to capital market considerations and because we believe that the PJM market will be sufficiently supplied for the next few years. A repowering project in New York City with a total capacity of 1,608 MW has been postponed until we see an improvement in the capital markets.

As a result of several recent events, including the United States economic recession, the price decline of our industry sector in the equity capital markets and the downgrading of the credit ratings of several of our significant competitors, the availability and cost of capital for our business and the businesses of our competitors has been adversely affected. In response to these events and the intensified scrutiny of companies in our industry sector by the rating agencies, we have reduced our planned capital expenditures by $2.7 billion over the 2002 - 2006 time frame.

DOMESTIC TRADING, MARKETING, POWER ORIGINATION AND RISK MANAGEMENT SERVICES OPERATIONS

In addition to our power generation operations, we trade and market power, natural gas and other energy-related commodities and provide related risk management services to our customers. Our domestic trading, marketing, power origination and risk management operations complement our domestic power generation operations by providing a full range of energy management services. These services include management of the sales and marketing of energy, capacity and ancillary services from these facilities, and also management of the purchase and sale of fuels and emission allowances needed to operate these facilities. Generally, we seek to sell a portion of the capacity of our domestic facilities under fixed-price sale contracts, fixed-capacity payments or contracts to sell power at a predetermined multiple of either gas or oil prices. This provides us with certainty as to a portion of our margins while allowing us to maintain flexibility with respect to the remainder of our generation output. We evaluate the regional forward power market versus our own fundamental analysis of projected future prices in the region to determine the amount of our capacity we would like to sell and the terms of sale pursuant to longer-term contracts. We also take operational constraints and operating risk into consideration in making these determinations. Generally, we seek to hedge a portion of our fuel costs, which are usually linked to a percentage of our power sales. We also market energy-related commodities and offer physical and financial wholesale energy marketing and price risk management products and services to a variety of customers. These customers include natural gas distribution companies, electric utilities, municipalities, cooperatives, power generators, marketers or other retail energy providers, aggregators and large volume industrial customers.

The following table illustrates the growth of our physical power and gas trading volumes since 1999.

TRADING VOLUMES

	FOR THE YEAR ENDED DECEM	
	1999	2000
Total Power (MWh(1))	82,381,103	171,618,485
Total Gas (Bcf(2))	1,564	2,423

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(1) Megawatt hours.

(2) Billion cubic feet.

Electric Power Trading and Marketing. We purchase electric power from other generators and marketers and sell power primarily to electric utilities, municipalities and cooperatives and other marketing companies. Our trading and marketing group is also responsible for the marketing of power produced from the power plants we own. We also provide risk management, physical and financial fuel purchase and power sales and optimization services to our customers.

Power Origination. Some of our employees focus on developing and providing customers with long-term customized products (power origination products). These products are designed and negotiated on a case-by-case basis to meet the specific energy requirements of our customers. Our power origination teams work closely with our trading and marketing group and our power generation group to sell long-term products from our power generation assets. They also work to leverage our market knowledge to capture attractive opportunities available through selling products that combine or repackage energy products purchased from third parties with other third-party products or with products from our power generation assets. Our efforts to sell power origination products from our power generation assets have been focused on longer-term forward sales to municipalities, cooperatives and other companies that serve end users, as well as sales of near-term products that are not widely traded. Our power origination products that combine or repackage third-party products are generally highly structured and therefore require the application of our commercial capabilities (e.g., power trading and asset positions).

Natural Gas Trading and Marketing. We purchase natural gas from a variety of suppliers under daily, monthly and term, variable-load and base-load contracts that include either market sensitive or fixed pricing provisions. We sell natural gas under sales agreements that have varying terms and conditions, most of which are intended to match seasonal and other changes in demand. We sold an average of 9.6 Bcf per day of natural gas in 2001, an average of 6.6 Bcf per day in 2000 and an average of 4.3 Bcf per day in 1999, some of which was sold to the natural gas distribution company subsidiaries of Reliant Energy. We plan to continue to purchase natural gas to supply to our power plants.

Our natural gas marketing activities include contracting to buy natural gas from suppliers at various points of receipt, aggregating natural gas supplies and arranging for their transportation, negotiating the sale of natural gas and matching natural gas receipts and deliveries based on volumes required by customers.

We arrange for, schedule and balance the transportation of the natural gas we market from the supply receipt point to the purchaser's delivery point. We generally obtain pipeline transportation to serve our customers. Accordingly, we use a variety of transportation arrangements for our customers, 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. As of December 31, 2001, we held over two bcf per day of firm transportation in the United States. In the normal course of business it is common for us to hedge the risk of pipeline transportation expenses through "basis swaps." To the extent we have contractually secured pipeline transportation rights in order to fulfill our obligations to sell gas at specific delivery points, or to acquire gas for our own requirements at generation facilities as part of our hedging strategy for power sales, and a pipeline experiences a force majeure event, our ability to transport gas on a contracted capacity basis could become impaired, which could affect the integrity of our hedged position.

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 winter heating and summer 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 addition to entering into contracts of natural gas storage capacity in strategic locations throughout the country, we are actively pursuing a natural gas storage development plan. These services are also intended to provide an additional level of performance security and backup services to our customers.

Other Commodities and Derivatives. We trade and market other energy-related commodities. We use derivative instruments to manage and hedge our fixed-price purchase and sale commitments and to provide fixed-price or floating-price commitments as a service to our customers and suppliers. We also use derivative instruments to reduce our exposure relative to the volatility of the cash and forward market prices and to protect our investment in storage inventories. For additional information regarding our financial exposure to derivative instruments, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K.

Intercontinental-Exchange. In July 2000, we, along with five other natural gas and power companies, American Electric Power, Aquila Energy, Duke Energy, El Paso Corporation and Mirant Corporation, made an investment in Intercontinental-Exchange, a new, web-based, on-line trading platform (www.intcx.com) for trading various commodities including precious metals, crude oil and refined products, natural gas and electricity. The other five natural gas and power companies, along with us, own less than 50% of Intercontinental - Exchange. In June 2001, Intercontinental-Exchange acquired the International Petroleum Exchange. With this acquisition, Intercontinental-Exchange became the first company to offer both an exchange trading over-the-counter commodity contracts and an exchange trading commodity futures contracts. At the same time, Intercontinental-Exchange announced plans to

integrate the two types of exchanges into a single electronic trading platform. Our decision to invest, as one of a group of natural gas and power companies, in Intercontinental-Exchange was based on a desire to support the development of a neutral, anonymous, electronic trading platform for bi-lateral energy transactions. We believe the commercial success of such an exchange model will benefit us by contributing to improved price transparency and transaction liquidity in the wholesale energy markets. The principal online competitors of Intercontinental-Exchange are currently TradeSpark.com and the NYMEX, a traditional futures exchange that has announced an online initiative.

Risk Management Controls. For information regarding our risk management structure and accounting policies, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Trading and Marketing Operations" in Item 7 of this Form 10-K and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K.

COMPETITION

For a discussion of competitive factors affecting our Wholesale Energy segment, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations - Increasing Competition in Our Industry" in Item 7 of this Form 10-K, which section is incorporated herein by reference.

EUROPEAN ENERGY

Our European Energy business segment includes 3,476 MW of power generation assets located in the Netherlands and a related trading and power origination operations. This segment includes the operations of Reliant Energy Power Generation Benelux N.V. (formerly UNA N.V.) (REPGB) and Reliant Energy Trading & Marketing B.V. and its affiliates.

In 2001, we evaluated strategic alternatives for our European Energy segment, including a possible sale. We completed our evaluation and have determined that given current market conditions and prices, it is not advisable to sell our European Energy operations. Consequently, we decided to continue to own and operate our European Energy segment and expand our trading and origination activities in Northwest Europe.

EUROPEAN POWER GENERATION OPERATIONS

Facilities. As of December 31, 2001 we owned five electric power generation facilities in the Netherlands with an aggregate net generating capacity of 3,476 MW and include approximately 39% of base-load, 36% of intermediate and 25% of peaking capacity. Our facilities are grouped in three clusters adjacent to the cities of Amsterdam, Utrecht and Velsen. In 2001, our generation facilities produced 14 million MWh, an amount which represented approximately 13% of the electricity production of the Netherlands (excluding electricity generated by cogeneration or other industrial processes). In addition to electricity, our generating stations sell heated water produced as a byproduct of the generation process for use in providing heating (district heating) to the cities of Amsterdam, Nieuwegein, Utrecht and Purmerend.

In 2001, approximately 51% of our European Energy segment's generation output was natural gas-fired, 30% was coal-fired, 18% was blast furnace gas-fired and less than 1% was oil-fired. Our European Energy segment purchases substantially all of its gas fuel requirements under medium to long-term gas purchase contracts 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.

Our European Energy segment historically purchased all of its coal requirements under short-term contracts with a coal trading and supply company now owned by two of the Dutch generation companies. In December 2001, REPGB and the other shareholder of the coal trading and supply company agreed to terminate future coal purchases through this entity effective in mid-2002. Our European Energy segment intends to obtain its future 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 Energy 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 Energy segment's generation plants have the flexibility to operate using blast furnace gas. We purchase the blast furnace gas from the adjacent steel plant under a medium-term and a long-term contract. We purchase our fuel oil requirements on the open market.

We acquired REPGB in October 1999 for approximately $1.9 billion (based on the then applicable exchange rate of 2.06 Dutch Guilders (NLG) per U.S. dollar). For information regarding the acquisition, please read note 5(b) to our consolidated financial statements.

Market Framework. Our European Energy segment produces, buys and sells electricity, gas and other energy-related commodities in the Northern European wholesale market. Its generation production activities are centered in the Netherlands, where it is one of the four large-scale generation companies. It operates five generation facilities with an installed capacity of 3,476 MW. Its energy trading and origination operations concentrate their activities primarily in the Netherlands, Germany and the Scandinavian regions. In the fourth quarter of 2001, our European Energy segment expanded its electricity trading operations to the United Kingdom.

The primary customers of our European Energy segment 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 individually 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 recent 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. For example, access to some European markets continues to be subject to transmission and other constraints. In some cases, fuel suppliers continue to operate in largely regulated markets not yet open to full competition.

EUROPEAN TRADING AND POWER ORIGINATION OPERATIONS

Our European Energy segment's trading and power origination operations are centered in Amsterdam, Netherlands, with additional offices in London and Frankfurt. Our European Energy segment trades electricity and fuel products in the Netherlands, Germany, Austria, Switzerland, the United Kingdom and the Scandinavian countries. Our marketing operations focus on distribution companies and large industrial and commercial customers in the Benelux and German markets. As of December 31, 2001, our European Energy segment had entered into forward purchase and sale contracts, and associated hedging transactions, covering approximately 18.6 million MWh for delivery in 2002.

Our European Energy segment's trading and power origination operations seek to utilize a business model, including risk management and related control policies, similar to that utilized in our Wholesale Energy operations in the United States. There are, however, 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 termination 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.

As of December 31, 2001, we had provided an aggregate of $831 million in guarantees with respect to contract obligations of the European Energy segment.

COMPETITION

For a discussion of competitive factors affecting our European Energy segment, please read "Management's Discussion and Analysis of Financial Condition and Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our European Energy Operations - Competition in the European Market" in Item 7 of this Form 10-K, which section is incorporated herein by reference.

RETAIL ENERGY

We provide electricity and related services to retail customers primarily in Texas through our wholly owned subsidiaries Reliant Energy Retail Services, LLC (Residential Services), Reliant Energy Solutions, LLC (Solutions) and StarEn Power, LLC (StarEn Power). As a retail electric provider, generally we procure or buy electricity from wholesale generators at unregulated rates, sell electricity at generally unregulated rates to our retail customers and pay the local transmission and distribution utilities a regulated tariff rate for delivering the electricity to our customers. We became a provider of retail electricity in Texas when that market began opening to retail competition in late 2001 and fully opened to retail competition in January 2002. In January 2002, we began to provide retail electricity services to all of the approximately 1.7 million customers of Reliant Energy's electric utility located in its service area who did not take action to select another retail electric provider. We provide electricity and related products and services to residential and small commercial (i.e., small and medium-sized business customers with a peak demand for power at or below one MW) customers through Residential Services, and offer customized, integrated electric commodity and energy management services to large commercial, industrial and institutional (e.g., hospitals, universities, school systems and government agencies) customers through Solutions for customers with a peak demand for power of greater than one MW. Residential Services, Solutions and StarEn Power have been certified as retail electric providers by the Texas Utility Commission. StarEn Power has been appointed by the Texas Utility Commission to be the provider of last resort (POLR) in certain areas of the State of Texas. Under the Texas electric restructuring law, a POLR is required to offer a standard retail electric service package to requesting customers of a class designated by the Texas Utility Commission within the POLR's territory at a fixed, nondiscountable rate.

In preparation for retail electric competition in Texas, we expanded our infrastructure of information technology systems, business processes and staffing levels to meet the needs of our retail businesses. These include a customer care system module and wholesale/retail energy supply, risk management, e-commerce, scheduling/settlement, customer relationship management and sales force automation systems. As of December 31, 2001, we had invested $153 million in retail infrastructure development. For additional information regarding the Texas retail electric market, please read " - Market Framework," " - Regulation - Texas - Retail Energy" and "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Retail Energy Operations - Competition in the Texas Market" in Item 7 of this Form 10-K.

RESIDENTIAL SERVICES

Residential Services provides electricity to residential retail and small commercial customers in Texas. As of January 1, 2002, Residential Services was the retail electric provider for approximately 1.5 million residential customers located in the Houston metropolitan area, making us the second largest retail electric provider in Texas as of that date. Residential Services' marketing strategy for residential customers emphasizes reliability and trust with our customers, and focuses on savings, value and customer service. We launched an advertising campaign to reposition our brand in the Houston and Dallas/Fort Worth metropolitan areas in the second half of 2001.

As the affiliated retail electric provider, or successor in interest, to Reliant Energy's electric utility, Residential Services was also the retail electric provider for approximately 200,000 small commercial customers in the Houston metropolitan area as of January 1, 2002. Residential Services' marketing strategy for small commercial customers uses a combination of direct marketing and individual sales calls to establish our brand and to attract additional customers.

As the affiliated retail electric provider, Residential Services will not be permitted to sell electricity to residential and small commercial customers in Reliant Energy's electric utility service territory at a price other than a fixed, specified price (price to beat) until January 1, 2005, unless before that date the Texas Utility Commission determines that 40% or more of the amount of electric power that was consumed in 2000 by the relevant class of customers in the service territory is committed to be served by other retail electric providers. In addition, the Texas electric restructuring law requires us, as the affiliated retail electric provider, to make the price to beat available to residential and small commercial customers in Reliant Energy's electric utility service territory through January 1, 2007, if requested by such customers. For more information about the price to beat, please read " - Regulation - Texas - Retail Energy."

SOLUTIONS

Solutions provides electricity and energy services to large commercial, industrial and institutional customers with whom it has signed contracts. In addition, it provides electricity at previously established default rates to those large commercial, industrial and institutional customers in the service territory of Reliant Energy's electric utility who have not entered into a contract with another retail electric provider. The majority of Solutions' revenues will come from the sale of electricity to its customers. In order to be classified as a large commercial customer, an electricity customer may aggregate the purchase of electricity for its own use at multiple locations such that the total peak demand exceeds one MW.

In addition to providing electricity, Solutions provides customized, integrated energy solutions, including risk management and energy services products, and demand side and energy information services to large commercial, industrial and institutional customers. Since its formation in April 1996, Solutions has completed over 220 energy services projects for large commercial, industrial and institutional clients. The services that Solutions provides its customers include the replacement or upgrade of energy-intensive capital equipment, the financing of energy-intensive equipment, infrastructure optimization, substation development and maintenance and power quality assurance.

Solutions is recognized as the affiliated retail electric provider, or successor in interest, to Reliant Energy's electric utility for large commercial, industrial and institutional customers. Solutions targets institutional, manufacturing, industrial and other large commercial customers, including multisite retailers and restaurants, petroleum refineries, chemical companies, real estate management firms, educational institutions and healthcare providers. As of December 31, 2001, this customer segment in Texas included approximately 1,750 buying organizations consuming an aggregate of approximately 16,000 MW of electricity at peak demand. As of December 31, 2001, Solutions had signed contracts with customers representing a peak demand of approximately 3,700 MW and serving approximately 12,000 meter locations.

STAREN POWER

StarEn Power serves as the POLR in portions of the state of Texas, as designated by the Texas Utility Commission. For 2002, StarEn Power has been appointed to serve as the POLR for residential and small commercial customers in the western portion of the Dallas/Fort Worth metropolitan area formally served by TXU Electric Company. In addition, StarEn Power has been appointed as the POLR in the service territory of Reliant Energy's electric utility for large commercial, industrial and institutional customers. The rates and terms under which StarEn Power provides service are governed by the terms of a settlement agreement between StarEn Power and various interested parties approved by the Texas Utility Commission. For additional information regarding our POLR obligations, rates and terms of service, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Retail Energy Operations - Obligations as a Provider of Last Resort" in Item 7 of this Form 10-K.

MARKET FRAMEWORK

The Texas electric restructuring law substantially amended the regulatory structure governing electric utilities in Texas in order to allow retail competition, which fully began in January 2002. In order to prepare for the opening of the retail market, a retail pilot project for up to 5% of each utility's load in all customer classes began in August

2001. For information regarding the retail market framework in Texas, please read " - Regulation - Texas - Retail Energy" and "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Retail Energy Operations" in Item 7 of this Form 10-K. Generally, under the Texas electric restructuring law, the retail electric provider procures or buys electricity from wholesale generators, sells electricity at retail to its customers and pays the transmission and distribution utility a regulated tariffed rate for delivering electricity to its customers. All retail electric providers in an area pay the same rates and other charges for transmission and distribution, whether or not they are affiliated with the transmission and distribution utility for that area. The transmission and distribution rates in effect as of January 1, 2002 for each utility were set through rate cases before the Texas Utility Commission.

RETAIL ENERGY SUPPLY

In Texas, our Wholesale Energy group and our Retail Energy group work together in order to determine the price, demand and supply of energy required to meet the needs of our Retail Energy segment's customers. Our Wholesale Energy trading and marketing operations are responsible for commodity pricing, risk assessment and supply procurement for our Retail Energy segment. Our Retail Energy segment manages retail pricing decisions and forecasts the demand for the procurement of electricity by the Wholesale Energy segment. The costs of our trading, marketing and risk management services associated with obtaining the electricity supply for our retail customers in Texas are borne by our Retail Energy segment. Our Wholesale Energy group acquires supply for our Retail Energy segment by several means. We may purchase capacity from non-affiliated parties in the capacity auctions mandated by the Texas Utility Commission. Please read " - Regulation - Texas - Retail Energy" for more information about these auctions. Under the terms of the Master Separation Agreement between Reliant Resources and Reliant Energy, we may also participate in and purchase up to approximately 50% of the remaining capacity of the generation facilities to be owned by Texas Genco sold in auctions substantially similar to, but separate from, the capacity auctions mandated by the Texas Utility Commission in which 15% of the total capacity of these facilities is required to be auctioned. In addition, we have the right to purchase 50% (but not less than 50%) of the remaining capacity of Texas Genco following the state mandated capacity auctions at prices to be established in the aforementioned Texas Genco auctions. Please read Notes 3 and 4(b) to our consolidated financial statements for a discussion of our participation in these auctions. We also enter into bilateral contracts with third parties for capacity, energy and ancillary services. We continuously monitor and update these positions based on retail sales forecasts and market conditions.

COMPETITION

For a discussion of competitive factors affecting our Retail Energy segment, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Retail Energy Operations - Competition in the Texas Market" in Item 7 of this Form 10-K, which section is incorporated herein by reference.

OTHER OPERATIONS

For 2001, our Other Operations business segment included:

- the operations of our venture capital division (New Ventures),
- the operations of our communications business (Communications), and
- unallocated corporate costs.

NEW VENTURES

Our New Ventures division manages our existing new technology investments and identifies and invests in promising new technologies and businesses that relate to our energy services operations. Focus areas for investment include distributed generation, clean energy and energy industry software and systems.

Generally, we make our investments either directly or indirectly as limited partners in venture capital funds. As of December 31, 2001, we have invested approximately $35 million in five venture capital funds with an energy and utility focus and have made commitments to invest an additional $11 million in these funds. As of December 31, 2001, these funds held investments in 43 companies. Excluding our investment in Grande Communications, Inc. discussed below, New Ventures' direct investment portfolio consists of eight companies with a total of $7 million invested as of December 31, 2001.

In September 2000, we committed to make a $25 million investment in Grande Communications, Inc., which was completed in August 2001. Grande Communications is a Texas-based communications company building a deep fiber broadband network that will offer bundled services, including high-speed Internet, all-distance telephone and advanced cable entertainment to homes and businesses. We invested a further $1 million in Grande Communications in October 2001 as part of a larger debt and equity financing for the company. Grande Communications has announced its intention to build a broadband network in the Houston area and has secured a cable franchise from the City of Houston. The Houston build out will be in addition to the Central Texas cities of Austin, San Marcos, and San Antonio which are already under development.

COMMUNICATIONS

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. For more information regarding the exiting of our Communication business, please read Note 16 to our consolidated financial statements.

REGULATION

OVERVIEW

We are subject to regulation by various federal, state, local and foreign governmental agencies, including the regulations described below.

FEDERAL ENERGY REGULATORY COMMISSION

Electricity. Under the Federal Power Act, 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 power at wholesale and are public utilities under the Federal Power Act with the exception of two facilities in Texas, which are qualifying facilities and not regulated as public utilities. The FERC has authorized these 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 excessive 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 issued Order No. 2000 in December 1999. Order No. 2000, which applies to all FERC jurisdictional transmission providers, describes the FERC's intention to promote the establishment of large RTOs and sets forth the minimum characteristics and functions of RTOs. Among the basic minimum characteristics are that the RTOs must be independent of market participants and must be of sufficient scope and geographical configuration. Order No. 2000 also encourages RTOs to work with each other to minimize or eliminate "seams" issues between RTOs

that operate as barriers to inter-regional transactions. The FERC's goal is to encourage the growth of a robust competitive wholesale market for electricity. Although jurisdictional transmission providers are not required to join RTOs, they are encouraged to do so. Under Order No. 2000, RTOs were to be operational by December 15, 2001. However, because RTO development was in different stages in different regions of the country, the FERC issued an order on November 7, 2001 extending the deadline until it resolves issues relating to geographic scope and governance of qualifying RTOs across the country and issues relating to business and procedural needs. For organizations to accomplish the functions of Order No. 2000, the FERC is taking steps to create business standards and protocols to facilitate RTO formation. However, there can be no assurance that the FERC's goals will be achieved. Also there is considerable state-level resistance in some regions, including regions in which we operate, to the formation of RTOs. At least 14 separate organizations, covering the substantial majority of all the FERC jurisdictional transmission providers, are in various stages of organization and have made at least preliminary filings with the FERC.

Trading and Marketing. Our domestic trading and marketing operations are also subject to the FERC's jurisdiction under the Federal Power Act. 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. We are also a "public utility" under the Federal Power Act, and our wholesale sales of electricity in interstate commerce are subject to a FERC-filed rate schedule that authorizes us to make sales at negotiated, market-based rates.

In authorizing market-based rates for various of our subsidiaries, the FERC has imposed some restrictions on these entities' transactions with Reliant Energy's electric utility, including a prohibition on the receipt of goods or services on a preferential basis. The FERC also has imposed restrictions on natural gas transactions between us and Reliant Energy's natural gas pipeline subsidiaries to preclude any preferential treatment. Similar restrictions apply to transactions between us and Reliant Energy's electric utility under Texas utility regulatory laws.

Hydroelectric Facilities. The majority of our generating facilities located in the state of New York are hydroelectric facilities, many of which are subject to the FERC's exclusive authority under the Federal Power Act 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.

TEXAS - RETAIL ENERGY

In June 1999, Texas adopted the Texas electric restructuring law. The Texas electric restructuring law substantially amended the regulatory structure governing electric utilities in Texas. Full retail competition in the service territories of some investor-owned electric utilities began in January 2002, and in the territories of any municipally-owned utility and electric cooperative that opts to open its market to retail competition. Under the Texas electric restructuring law, the traditional, vertically-integrated utility is required to separate its generation, transmission and distribution, and retail activities. Unlike the vertically-integrated utility, which was subject to cost-of-service rate regulation, the profit earned by retail electric providers will not be subject to regulation, except for the price to beat requirement described below. The transmission and distribution business will continue to be subject to cost-of-service rate regulation and will be responsible for the delivery of electricity to retail customers through retail electric providers. Wholesale power generators will continue to sell electric energy to purchasers, including retail electric providers, at unregulated rates. To facilitate a competitive market, each power generator affiliated with a transmission and distribution utility is required to sell at auction 15% of the output of its installed generating capacity. This auction obligation continues until January 1, 2007, unless the Texas Utility Commission determines before that date that at least 40% of the quantity of electric power consumed in 2000 by residential and small commercial customers in the affiliated transmission and distribution utility's service area is being served by retail electric providers not affiliated with the incumbent utility. An affiliated retail electric provider may not purchase capacity sold by its affiliated power generation company in the state mandated capacity auctions.

The Texas electric restructuring law allows most retail electric customers of Texas investor-owned electric utilities, and those of any municipally-owned utility or electric cooperative that opts to open its market to retail competition, to take action to select their retail electric provider for service as of January 1, 2002. Retail electric providers which are affiliates of, or successors in interest to, electric utilities may compete substantially statewide for these sales, but prices they may charge to residential and small commercial customers within the affiliated

electric utility's traditional service territory are subject to a fixed, specified price (price to beat) at the outset of retail competition. The price to beat is subject to potential adjustments up to two times per year, as described below. In December 2001, the Texas Utility Commission established the price to beat we are required to charge our residential and small commercial customers for electricity sales in the Houston metropolitan area. Our price to beat was set at a level resulting in an estimated 17% reduction to pre-existing rates for our residential customers and an estimated 22% reduction to pre-existing rates for our small commercial customers.

Municipally-owned utilities and electric cooperatives have the option to open their markets to retail competition any time after January 1, 2002. However, until a municipally-owned utility or electric cooperative adopts a resolution opting to open its market to retail competition, it may not offer electric energy at unregulated prices to retail customers outside its service area. In November 2001, Nueces Electric Cooperative and San Patricio Electric Cooperative received Texas Utility Commission approval of required filings necessary to open their markets to retail competition. Some large Texas cities, including San Antonio and Austin, are served by municipally-owned utilities that have not announced when or if they will open their markets to competition.

New, unaffiliated retail electric providers that enter a particular market may sell electricity to residential and small commercial customers at any price, including a price below the price to beat. By allowing non-affiliated retail electric providers to provide retail electric service to customers in an electric utility's traditional service territory at any price, including a price below the price to beat, the Texas electric restructuring law is designed to encourage competition among retail electric providers. Affiliated retail electric providers will not be permitted to sell electricity to residential and small commercial customers in the transmission and distribution utility's traditional service territory at a price other than the price to beat until January 1, 2005, unless before that date the Texas Utility Commission determines that 40% or more of the amount of electric power that was consumed in 2000 by the relevant class of customers in the certificated service area of the affiliated transmission and distribution utility is committed to be served by other retail electric providers. 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 traditional service area of the related incumbent utility through 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). Electric services provided to large commercial, industrial and institutional customers (i.e., customers with an aggregate peak demand of greater than one MW), whether by the affiliated retail electric provider or a non-affiliated retail electric provider, may be provided at any negotiated price.

The Texas Utility Commission'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 price of natural gas. The fuel factor included in our price to beat was initially set by the Texas Utility Commission at the then average forward 12 month gas price strip of approximately $3.11/mmbtu. In addition, the affiliated retail electric provider may also request an adjustment as a result of changes in its price of purchased energy. In such a request, the affiliated retail electric provider 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 Texas Utility Commission. An affiliated retail electric provider may request that its price to beat be adjusted twice a year. Currently, we cannot estimate with any certainty the magnitude and timing of the adjustments required, if any, and the eventual impact of such adjustments on headroom. To the extent that the adjustments are not received on a timely basis, our results of operations may be adversely affected. Based on forward gas prices at the end of March 2002, we estimate that we would be able to increase our price to beat by between approximately 4% and 5%.

The Texas electric restructuring law requires the affiliated retail electric provider to reconcile and credit to the affiliated transmission and distribution utility in early 2004 any positive difference between the price to beat, reduced by a specified delivery charge, and the prevailing market price of electricity unless the Texas Utility Commission determines that, 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 the affiliated transmission and distribution utility's traditional service territory is committed to be served by other non-affiliated retail electric providers. If the 40% test is not met, the reconciliation and credit will be in the form of a payment to Reliant Energy, not to exceed $150 per customer. For additional information regarding this payment, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Consolidated Capital Requirements and Uses of Cash - Payment to Reliant Energy" in Item 7 of this Form 10-K and Note 13(g) to our consolidated financial statements.

The Texas electric restructuring law requires the Texas Utility Commission to designate retail electric providers as POLR in areas of the state in which retail competition is in effect. A POLR is required to offer a standard retail electric service package for each class of customers designated by the Texas Utility Commission at a fixed, nondiscountable rate approved by the Texas Utility Commission, and is required to provide the service package to any requesting retail customer in the territory for which it is the POLR. In the event that another retail electric provider fails to serve any or all of its customers, the POLR is required to offer that customer the standard retail service package for that customer class with no interruption of service to the customer. For additional information regarding our obligation as a POLR, and regarding the Texas retail market framework in general, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Retail Energy Operations" in Item 7 of this Form 10-K.

SECURITIES AND EXCHANGE COMMISSION - PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

Under the Energy Policy Act of 1992, 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 Public Utility Holding Company Act of 1935 (1935 Act) as an exempt wholesale generator (EWG). Qualifying facilities, such as two of our projects in Texas, are similarly exempt from regulation under the 1935 Act. Our electric generation facilities have received determinations of EWG status from the FERC. If any of these subsidiaries lose their EWG or qualifying facility status, we would have to restructure our organization or risk being subjected to regulation under the 1935 Act.

Reliant Energy is both a holding company and an electric utility as defined in the 1935 Act. However, Reliant Energy is exempt from regulation as a holding company under Section 3(a)(2) of the 1935 Act.

REPGB is a foreign utility company exempt from regulation as a "public utility company" under the 1935 Act. The Texas Utility Commission and the state regulatory commissions of Arkansas and Minnesota have imposed limitations on the amount of investments that Reliant Energy or its subsidiaries may invest in foreign utility companies and, in some cases, foreign electric wholesale generating companies. These limitations are based upon Reliant Energy's consolidated net worth, retained earnings, and debt and stockholders' equity, respectively. Subject to some limited exceptions, the 1935 Act also prohibits any public utility from issuing any security for the purpose of financing the acquisition, ownership or operation of a foreign utility company, or assuming any obligation or liability in respect of any security of a foreign utility company.

In connection with its business separation plan, Reliant Energy plans to restructure its remaining businesses and to register as a public utility holding company under the 1935 Act or to seek an exemption from the registration requirements of the 1935 Act. If Reliant Energy becomes a registered public utility holding company prior to the distribution of our common stock to its shareholders, we will be subject to regulation as a "subsidiary company" under the 1935 Act. As a result, we would be subject to limitations under the 1935 Act related to, among other things, our acquisition, ownership and operation of energy assets outside of our current business plan and payments of dividends by us and our subsidiaries from unearned surplus. Additionally, we would need to obtain approval under the 1935 Act prior to acquiring the voting securities of any public utility or taking any other actions that would result in affiliation with another public utility. Following the Distribution, we would no longer be subject to the provisions of the 1935 Act either as a subsidiary or an affiliate of Reliant Energy.

THE NETHERLANDS

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. The remuneration included fuel cost, return of and on capital and operation and maintenance expenses. Under a transitional agreement which expired in 2000, the non-fuel portion of this amount was fixed during the period 1997 through 2000. For additional information, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our European Energy Operations - Competition in the European Market" and " - Deregulation of the Dutch Market" in Item 7 of this Form 10-K.

In 2001, the wholesale energy market of our European Energy segment's primary market in the Netherlands was opened to competition. Our European Energy segment continues to be subject to regulation by a number of national and European regulatory agencies and regulations relating to the environment, labor, tax and other matters. For example, our European Energy segment's operations are subject to the regulation of Dutch and European Community anti-trust authorities, who have extensive authority to investigate and prosecute violations by energy companies of anti-monopolistic and price-fixing regulations. In addition, our European Energy segment must also comply with various national and regional grid codes and other regulations establishing access to transmission systems. Many of the significant suppliers and customers of our European Energy segment are subject to continued regulation by various energy regulatory bodies that have the authority to establish tariffs for such entities. The impact of regulations on these entities has an indirect impact on our European Energy segment.

In some European countries, it is uncertain to what extent companies trading in energy, fuel and other commodities (physical and financial) might be deemed subject to regulation as brokers and dealers under local securities laws. To the extent that its operations are deemed subject to these laws, our European Energy segment could become subject to minimum capitalization, licensing and reporting requirements similar to that which exists for securities broker and dealer firms. Although our European Energy segment believes that its operations are currently outside the scope of such regulations, no assurance can be given as to the future positions of these regulatory agencies regarding the applicability of these regulations to our European Energy segment's operations.

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. For the domestic and European operations we owned as of December 31, 2001, we anticipate spending approximately $135 million in capital and other special project expenditures between 2002 and 2006 for environmental compliance. Additionally, environmental capital expenditures for the recently acquired Orion Power assets were estimated by Orion Power to be $241 million over the same time period. We are currently reviewing these estimates.

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.

AIR EMISSIONS

As part of the 1990 amendments to the Federal Clean Air Act (Clean Air Act), requirements and schedules for compliance were developed for attainment of health-based standards. As part of this process, standards for the emission of NOx, a product of the combustion process associated with power generation and natural gas

compression, are being developed or have been finalized. The standards require reduction of emissions from our power generating units in the United States.

Our REPGB facilities in the Netherlands were in compliance with applicable Dutch NOx emission standards through the year 2001. New NOx reduction targets have recently been adopted in the Netherlands which will require a 50% reduction in NOx emissions 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. We currently believe that REPGB facilities will not be required to install NOx controls or purchase emission credits until the 2005 through 2006 time period. Projected emission control costs are estimated to be approximately $30 million, although this investment may be offset to some extent or delayed if a market-based trading program develops.

The Environmental Protection Agency (EPA) has announced its determination to regulate hazardous air pollutants (HAPs), including mercury, from coal-fired and oil-fired steam electric generating units under Section 112 of the Clean Air Act. The EPA plans to develop maximum achievable control technology (MACT) standards for these types of units. 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 the units cannot be predicted at this time and may adversely impact our results of operations. In addition, a request for reconsideration of the EPA's decision to impose MACT standards has been filed with the EPA. We cannot predict the outcome of the request.

In 1998, the United States became a signatory to 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. 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 European Union, of which the Netherlands is a member, has adopted the Kyoto Protocol as the goal for greenhouse gas emission targets. We expect REPGB, through use of "green fuels" and efficiency improvements, will be able to meet its portion of the target reductions.

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 a previously adopted EPA ambient air quality standards for fine particulate matter and ozone. While attaining this new standard 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.

Multi-pollutant air emission initiative. On February 14, 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 (SO_2), NO_x, and mercury. In addition, a voluntary program for greenhouse gas emissions is proposed as an alternative to the Kyoto Protocol discussed above. The implementation of the initiative, if approved by the United States Congress, would be a market-based program, modeled after the Acid Rain Program, beginning in 2008 and phased full compliance by 2018. Fossil fuel-fired power plants in the United States would be affected by the adoption of this program, or other legislation currently pending in 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.

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WATER ISSUES

In July 2000, the EPA issued final rules for the implementation of the Total Maximum Daily Load program of the Clean Water Act (TMDL). The goal of the TMDL rules is to establish, over the next 15 years, the maximum amounts of various pollutants that can be discharged into waterways while keeping those waterways in compliance with water quality standards. The establishment of TMDL values may eventually result in more stringent discharge limits in each facility's discharge permit. Such limits may require our facilities to install additional water treatment, modify operational practices or implement other wastewater control measures. Certain members of the United States Congress have expressed concern to the EPA about the TMDL program and the EPA, in October 2001, extended the effective date of the regulation until April 2003.

In November 2001, the EPA promulgated rules that impose additional technology based requirements on new cooling water intake structures. Draft rules for existing intake structures have also been issued. It is not known at this time what requirements the final rules for existing intake structures will impose and whether our existing intake structures will require modification as a result of such requirements. The process by which the intake structure rules were written was a contentious one and litigation is expected. Court action in response to this expected litigation could result in unforeseen changes in the requirements.

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

Under the purchase agreements between Sithe Energies and Reliant Energy Power Generation, Inc. (REPG) relating to some of our Northeast regional facilities, and in the transaction with Orion Power, we, with a few exceptions, assumed liability for preexisting conditions, including some ongoing remediations at the electric generating stations. Funds for carrying out any identified actions have been included in our planning for future 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 (PaDEP) to remediate a coal refuse pile on the property of the facility. We expect the remediation will cost between $10 million and $15 million. Under the acquisition agreements between Sithe Energies and GPU, Inc. relating to some of our Northeast 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 that $6 million. In August 2000 we signed a modified consent order that committed us to complete the remediation work no later than November 2004. In addition to the coal refuse site at this facility, we had liabilities associated with six future ash disposal site closures and six current site investigations and environmental remediations. We expect to pay approximately $16 million over the next five years to monitor and remediate these sites.

Under the New Jersey Industrial Site Recovery Act (ISRA), owners and operators of industrial properties are responsible for performing all necessary remediation at the facility prior to the closing of a facility and the termination of operations, or undertaking actions that ensure that the property will be remediated after the closing of a facility and the termination of operations. In connection with the acquisition of our facilities from Sithe Energies, we have agreed to take responsibility for any costs under ISRA relating to the four New Jersey properties we purchased. We estimate that the costs to fulfill our obligations under ISRA will be approximately $10 million. 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 has been received from the Florida Department of Environmental Protection. A study to evaluate the cause of the elevated constituents has been undertaken. At this time, if remediation is required, the cost, if any, is not anticipated to be material.

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 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. We are not aware of any liabilities under CERCLA that would have a material adverse effect on us, our financial position, results of operations or cash flows.

EUROPEAN ENERGY

European and Dutch environmental laws are among the most stringent in the industrial world. 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 and other fossil fuel. The environmental laws also address public safety. We believe our European Energy segment holds all necessary authorizations and approvals for its current operations.

The European Union, of which the Netherlands is a member, adopted the Kyoto Protocol as the goal for greenhouse gas emission targets. For further discussion of the protocol, please read " - Air Emissions." 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.

NOx reduction targets will require a 50 percent reduction in NOx emissions 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 NOx emission standards. Based on current factors, we believe that our European facilities will not be required to install NOx controls or purchase emission credits until the 2005-2006 time period.

We estimate that we will spend approximately $30 million in emission control and other environmental costs associated with our European Energy segment for the period 2002 through 2006. In addition, we expect to spend approximately $18 million in asbestos and other environmental remediation programs during this period.

EMPLOYEES

As of December 31, 2001, we had 5,052 full-time employees. Of these employees, 1,555 are covered by collective bargaining agreements. The collective bargaining agreements expire on various dates until May 15, 2007. The following table sets forth the number of our employees by business segment as of December 31, 2001.

SEGMENT	NUMBER
Wholesale Energy	2,395
European Energy	916
Retail Energy	1,202
Other Operations	539
Total	5,052

EXECUTIVE OFFICERS
(AS OF MARCH 1, 2002)

NAME	AGE	PRESENT POSITION
R. Steve Letbetter..................	53	Chairman, President and Chief Executive Officer
Robert W. Harvey....................	46	Executive Vice President and Group President, Retail
Stephen W. Naeve....................	54	Executive Vice President and Chief Financial Officer
Joe Bob Perkins.....................	41	Executive Vice President and Group President, Wholes
Hugh Rice Kelly.....................	59	Senior Vice President, General Counsel and Corporate
Mary P. Ricciardello................	46	Senior Vice President and Chief Accounting Officer

R. STEVE LETBETTER is our Chairman, President and Chief Executive Officer. Mr. Letbetter also serves as Chairman, President and Chief Executive Officer of Reliant Energy. He has been Chairman of Reliant Energy since January 2000 and President and Chief Executive Officer since June 1999. Since 1978, he has served in various positions as an executive officer of Reliant Energy and its corporate predecessors. Mr. Letbetter has been a director of Reliant Energy since 1995. Mr. Letbetter will resign as President and Chief Executive Officer of Reliant Energy at the time of the Distribution, but will continue to serve as non-executive Chairman until 2004, subject to his re-election annually as Chairman by the board of directors.

ROBERT W. HARVEY is our Executive Vice President and Group President, Retail Businesses. Mr. Harvey has also served as Vice Chairman of Reliant Energy since June 1999. 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 will resign as Vice Chairman of Reliant Energy at the time of the Distribution.

STEPHEN W. NAEVE is our Executive Vice President and Chief Financial Officer. He has also served as Vice Chairman of Reliant Energy since June 1999 and as Chief Financial Officer of Reliant Energy since 1997. From 1997 to 1999, Mr. Naeve held the position of Executive Vice President and Chief Financial Officer of Reliant Energy. Since 1988, he served in various executive officer capacities with Reliant Energy, including Vice President - Strategic Planning and Administration between 1993 and 1996. Mr. Naeve will resign as Vice Chairman and Chief Financial Officer of Reliant Energy at the time of the Distribution.

JOE BOB PERKINS is our Executive Vice President and Group President, Wholesale Businesses. He served as President and Chief Operating Officer, Reliant Energy Wholesale Group and as President and Chief Operating Officer of Reliant Energy Power Generation, Inc. since 1998. In 1998, Mr. Perkins served as President and Chief Operating Officer of the Reliant Energy Power Generation Group. Between 1996 and 1998, he served as Vice President - Corporate Planning and Development.

HUGH RICE KELLY is our Senior Vice President, General Counsel and Corporate Secretary. He has also served as Executive Vice President, General Counsel and Corporate Secretary of Reliant Energy since 1997. Between 1984 and 1997, he served as Senior Vice President, General Counsel and Corporate Secretary of Reliant Energy. Mr. Kelly will resign as an officer of Reliant Energy at the time of the Distribution.

MARY P. RICCIARDELLO is our Senior Vice President and Chief Accounting Officer. She has also served as Chief Accounting Officer of Reliant Energy since June 2000 and as Senior Vice President since 1999. She previously served as Vice President and Comptroller of Reliant Energy from 1996 through 1999, and in various executive officer capacities with Reliant Energy since 1993. Ms. Ricciardello will resign as an officer of Reliant Energy at the time of the Distribution.

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 2003, subject to 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 - European Power Generation Operations" in Item 1 of this Form 10-K. 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.

WHOLESALE ENERGY

For information regarding the properties of our Wholesale Energy segment, please read "Our Business - Wholesale Energy" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

EUROPEAN ENERGY

For information regarding the properties of our European Energy segment, please read "Our Business - European Energy - European Power Generation Operations" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

RETAIL ENERGY

For information regarding the properties of our Retail Energy segment, please read "Our Business - Retail Energy" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

OTHER OPERATIONS

For information regarding the properties of our Other Operations segment, please read "Our Business - Other Operations" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

ITEM 3. LEGAL PROCEEDINGS.

For a description of certain legal and regulatory proceedings affecting us, please read Notes 13(e), 13(i) and 17 to our consolidated financial statements, which notes are incorporated herein by reference.

RESTATEMENT OF SECOND AND THIRD QUARTER 2001 RESULTS OF OPERATIONS

On February 5, 2002, we announced that we were restating our earnings for the second and third quarters of 2001. As more fully described in our March 15, 2002 Current Report on Form 8-K, the restatement related to a correction in accounting treatment for a series of four structured transactions that were inappropriately accounted for as cash flow hedges for the period of May 2001 through September 2001, rather than as derivatives with changes in fair value recognized through the income statement. Each structured transaction involved a series of forward contracts to buy and sell an energy commodity in 2001 and to buy and sell an energy commodity in 2002 or 2003.

At the time of the public announcement of our intention to restate our reporting of the structured transactions, the Audit Committee of our Board of Directors instructed us to conduct an internal audit review to determine whether there were any other transactions included in the asset books as cash flow hedges that failed to meet the cash flow hedge requirements under SFAS No. 133. This targeted internal audit review found no other similar transactions.

The Audit Committee also directed an internal investigation by outside legal counsel of the facts and circumstances leading to the restatement, which investigation has been completed. In connection with the restatement and related investigations, the Audit Committee has met eight times to hear and assess reports from the investigative counsel regarding its investigation and contacts with the Staff of the SEC. To address the issues identified in the investigation process, the Audit Committee and management have begun analyzing and implementing remedial actions, including, among other things, changes in organizational structure and enhancement of internal controls and procedures.

On April 5, 2002, we were advised that the Staff of the Division of Enforcement of the SEC is conducting an informal inquiry into the facts and circumstances surrounding the restatement. We are cooperating with this inquiry. Before releasing our 2001 earnings, we received concurrence from the SEC's accounting staff on the accounting treatment of the restatement, which increased our earnings for the two quarters by a total of $134 million. At this time, we cannot predict the outcome of the SEC's inquiry. In addition, we cannot predict what effect the inquiry may have on Reliant Energy's pending application to the SEC under the 1935 Act, which is required for Reliant Energy's restructuring. For more information about Reliant Energy's restructuring, please read " - Formation, Initial Public Offering and Anticipated Distribution."

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

No matters were submitted to a vote of Reliant Resources' security holders during the fourth quarter of the fiscal year ended December 31, 2001.

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PART II

ITEM 5. MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

As of April 1, 2002, our common stock was held of record by approximately 41 stockholders of record and approximately 15,000 beneficial owners. Our common stock is listed on the New York Stock Exchange and is traded under the symbol "RRI."

We completed the initial public offering of our common stock in May 2001. Our common stock began trading on the New York Stock Exchange on May 1, 2001. 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	LOW
2001		
Second Quarter (from May 1 through June 30)		
May 21	$ 36.75	
June 26		$ 24.48
Third Quarter		
July 10	$ 27.96	
September 27		$ 15.75

Fourth Quarter		
October 16....................................	$ 19.65	
December 17....................................		$ 13.55

The closing market price of our common stock on December 31, 2001 was $16.51 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.

ITEM 6. SELECTED FINANCIAL DATA.

The following tables present our selected consolidated financial data. The financial data set forth below for 1997, 1998, 1999 and 2000 are derived from the consolidated historical financial statements of Reliant Energy. 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. 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 DE		
	1997(1)	1998(1)	1999(1
	(IN MILLIONS, EXCEPT PER		
INCOME STATEMENT DATA:			
Revenues	$ 1,321	$ 4,371	$ 6
Expenses:			
Fuel and cost of gas sold	978	2,352	3
Purchased power	313	1,824	2
Operation and maintenance	17	65	
General, administrative and development	20	78	
Depreciation and amortization	2	15	
Total	1,330	4,334	6
Operating (Loss) Income	(9)	37	
Other (Expense) Income:			
Interest expense	(1)	(2)	
Interest income	--	1	
Interest income (expense) - affiliated companies, net	2	2	
Gains (losses) from investments	--	--	

(Loss) income of equity investments of unconsolidated subsidiaries	--	(1)	
Gain on sale of development project	--	--	
Other, net	--	1	
Total Other Income (Expense)	1	1	
(Loss) Income Before Income Taxes, Extraordinary Item and Cumulative Effect of Accounting Change	(8)	38	
Income Tax Benefit (Expense)	2	(17)	
(Loss) Income Before Extraordinary Item and Cumulative Effect of Accounting Change	(6)	21	
Extraordinary Item, net of tax	--	--	
Cumulative effect of accounting change, net of tax	--	--	
Net (Loss) Income	$ (6)	$ 21	$
BASIC AND DILUTED EARNINGS PER SHARE:			
Income before cumulative effect of accounting change			
Cumulative effect of accounting change, net of tax			
Net income			

	YEAR ENDED DECEMBER 31,		
	1997(1)	1998(1)	1999(1)(3)
	(IN MILLIONS, EXCEPT OPERATING		
STATEMENT OF CASH FLOW DATA:			
Cash Flows From Operating Activities	$ (22)	$ (2)	$ 35
Cash Flows From Investing Activities	(4)	(365)	(1,406)
Cash Flows From Financing Activities	26	379	1,408
OTHER OPERATING DATA:			
Net Power Generation Capacity (MW)	--	3,800	7,945
Domestic Wholesale Power Sales (MMWh)(4)	12	65	82
Domestic Natural Gas Sales (Bcf)(5)	366	1,115	1,564
European Power Sales (MMWh)	--	--	3

	DECEMBER 31		
	1997	1998	1999

			(IN MILLIONS)
BALANCE SHEET DATA:			
Property, Plant and Equipment, net	$ 5	$ 270	$ 2,407
Total Assets	822	1,409	5,624
Short-term Borrowings	--	--	170
Long-term Debt to Third Parties, including current maturities	--	--	460
Accounts and Notes Receivable (Payable) - Affiliated Companies, net	45	(17)	(1,333)
Stockholders' Equity	291	652	741

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(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: Reliant Energy Services, Inc. and Arkla Finance Corporation acquired in August 1997, the five generating facilities in California substantially acquired in April 1998, a generating facility in Florida and REPGB both acquired in October 1999 and the REMA acquisition that occurred in May 2000. Please read Note 5 to our consolidated financial statements for further information about these acquisitions.

(2) Effective January 1, 2001, we adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" as amended (SFAS No. 133), which established accounting and reporting standards for derivative instruments. Please read Note 6 to our consolidated financial statements for further information regarding the impact of the adoption of SFAS No. 133.

(3) As described in Note 1 to our consolidated financial statements, our consolidated financial statements for 1999, 2000 and 2001 have been restated from amounts previously reported. The restatement had no impact on previously reported consolidated cash flows, operating income or net income.

(4) Million megawatt hours.

(5) Billion cubic feet.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

RESTATEMENT

On May 9, 2002, Reliant Resources determined that it had engaged in same-day commodity trading transactions involving purchases and sales with the same counterparty for the same volume at substantially the same price, which the personnel who effected these transactions apparently did so with the sole objective of increasing volumes. Reliant Resources commenced a review to quantify the amount and assess the impact of these trades (round trip trades). The Audit Committees of each of the Board of Directors of Reliant Resources and Reliant Energy also directed an internal investigation by outside legal counsel, with assistance by outside accountants, of the facts and circumstances relating to the round trip trades and related matters.

We currently report all trading, marketing and risk management services transactions on a gross basis with such transactions being reported in revenues and expenses except primarily for financial gas transactions such as swaps. Therefore, the round trip trades were reflected in both our revenues and expenses. The round trip trades should not have been recognized in revenues or expenses (i.e. they should have been reflected on a net basis). However, since the round trip trades were done at the same volume and substantially the same price, they had no impact on our reported cash flows, operating income or net income. In addition to the round trip trades reported on May 13, 2002, we also identified an additional transaction in 1999, which based on available information, Reliant Resources believes was also recorded with the sole objective of increasing volumes but also resulted in increased revenues and fuel and cost of gas sold expense.

In addition, during the May 2001 through September 2001 time frame, we entered into four structured transactions involving a series of forward or swap contracts to buy and sell an energy commodity in 2001 and to buy and sell an energy commodity in 2002 or 2003 (four structured transactions). The four structured transactions were intended to increase future cash flow and earnings and to increase certainty associated with future cash flow and earnings, albeit at the expense of 2001 cash flow and earnings. Each series of contracts in a structure were executed contemporaneously with the same counterparty and were for the same commodities, quantities and locations. The contracts in each structure were offsetting in terms of physical attributes. The transactions that settled in 2001 were previously recorded on a gross basis with such transactions being reported in revenues and expenses which resulted in $1.5 billion of revenues, $364 million in fuel and cost of gas sold and $1.2 billion of purchased power expense being recognized during the period from May 2001 through December 31, 2001. Having further reviewed the transactions, we now believe these transactions should have been accounted for on a net basis.

In the course of our review, we also identified and determined to record on a net basis several transactions for energy related services (not involving round trip trades) that totaled $85 million over the three year period ended December 31, 2001. These transactions were originally recorded on a gross basis.

During the fourth quarter of 2000, two power generation swap contracts with a fair value of $261 million were terminated and replaced with a substantially similar contract providing for physical delivery and designated to hedge electric generation. The termination of the original contracts and execution of the replacement contract represented a substantive modification to the original contract. As a result, upon termination of the original contracts, a contractual liability representing the fair value of the original contracts and a deferred asset of equal amount should have been recorded. As of January 1, 2001, in connection with the adoption of Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended, the deferred asset should have been recorded as a transition adjustment to other comprehensive loss. The liability and transition adjustment should have been amortized on a straight-line basis over the term of the power generation contract replacing the terminated power generation contracts (through May 2004). We previously did not give accounting recognition to these transactions. As a result, we have restated our Consolidated Balance Sheets as of December 31, 2000 and 2001 and the Statement of Consolidated Stockholders' Equity and Comprehensive Income for the year ended December 31, 2001, to appropriately account for these transactions as described above. The restatement had no impact on our reported consolidated cash flows, operating income or net income.

The consolidated financial statements for 1999, 2000 and 2001 have been restated from amounts previously reported. The restatement had no impact on previously reported consolidated cash flows, operating income or net income. A summary of the principal effects of the restatement on our consolidated financial statements for 1999, 2000 and 2001 are set forth in Note 1 to our consolidated financial statements.

The following discussion and analysis has been modified for the restatement and should be read in combination with our consolidated financial statements and notes to those statements included in Item 8 of this Form 10-K.

OVERVIEW

We provide electricity and energy services with a focus on the competitive wholesale and retail segments of the electric power industry in the United States. We acquire, develop and operate electric power generating facilities that are not subject to traditional cost-based regulation and therefore can generally sell power at prices determined by the market. We also trade and market power, natural gas and other energy-related commodities and provide related risk management services.

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. Our segments include Wholesale Energy, European Energy, Retail Energy and Other Operations. For segment reporting information, please read Note 18 to our consolidated financial statements.

OUR SEPARATION FROM RELIANT ENERGY, INCORPORATED

In connection with our anticipated separation from Reliant Energy, Incorporated (Reliant Energy), Reliant Energy contributed to us effective December 31, 2000, our wholesale, retail and other operations. Through December 31, 2000, these operations were conducted by Reliant Energy and its direct and indirect subsidiaries. These operations consist of the following:

- non-rate regulated power generation assets and related energy trading, marketing, power origination and risk management operations in North America and Northwest Europe,

- retail electric operations, and

- other operations, including venture capital and Communications businesses.

For additional information regarding agreements with Reliant Energy entered into as a part of Reliant Energy's business separation plan, please read Note 4 to our consolidated financial statements.

The financial information for the years ended December 31, 1999 and 2000 discussed in this section is derived from the consolidated historical financial statements of Reliant Energy, which include the results of operations for all of Reliant Energy's businesses, including those businesses which we do not own. In order to prepare our financial statements for 1999 and 2000, contained in this Form 10-K and discussed in this section, we carved out the results of operations of the businesses that we own from Reliant Energy's consolidated historical financial statements. Accordingly, the results of operations discussed in this section 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 Reliant Energy 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 Reliant Energy. We may experience changes in our cost structure, funding and operations as a result of our anticipated separation from Reliant Energy, including increased costs associated with reduced economies of scale, and increased costs associated with being a publicly traded, independent company. We cannot currently predict with any certainty the actual amount of increased costs we may incur, if any.

In May 2001, we offered 59.8 million shares of our common stock to the public at an initial public offering (IPO) price of $30 per share and received net proceeds of $1.7 billion. Pursuant to the master separation agreement with Reliant Energy (Master Separation Agreement), we used $147 million of the net proceeds to repay certain indebtedness owed to Reliant Energy. Reliant Energy has publicly disclosed that it expects to distribute (Distribution) the remaining Reliant Resources common stock that it owns to its or its successor's shareholders in the summer of 2002. The Distribution is subject to the declaration of the Distribution by the Board of Directors of Reliant Energy, market and other conditions and government actions and approvals. We cannot assure you that the Distribution will be completed as described or within the time period outlined above.

CONSOLIDATED RESULTS OF OPERATIONS

The following table provides summary data regarding our consolidated results of operations for 1999, 2000 and 2001.

	YEAR ENDED DECEMBER 31,	
	1999	2000
	(IN MILLIONS)	
Revenues	$ 6,539	$ 18,722
Operating Expenses	6,525	18,284
Operating Income	14	438
Other Income (Expense), net	12	(147)
Income Tax Expense	2	88
Income Before Extraordinary Gain and Cumulative Effect of Accounting Change	24	203
Extraordinary Gain	--	7
Cumulative Effect of Accounting Change, net of tax	--	--
Net Income	$ 24	$ 210

2001 COMPARED TO 2000

Net Income. We reported consolidated net income of $557 million, or $2.01 earnings per share, for 2001 compared to $210 million for 2000. The 2001 results included a cumulative effect of accounting change of $3 million, net of tax, related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended. For additional discussion of the adoption of SFAS No. 133, please read Note 6 to our consolidated financial statements. 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, please read Note 8(b) to our consolidated financial statements. Our consolidated net income, before cumulative effect of accounting change, was $554 million for 2001 compared to consolidated net income, before extraordinary gain, of $203 million for 2000. The increase of $351 million was primarily due to the following:

- a $674 million increase in gross margins (revenues less fuel and cost of gas sold and purchased power) from our Wholesale Energy segment, excluding the impact of a $68 million provision related to energy sales to Enron Corp. and its affiliates (Enron) which filed a voluntary petition for bankruptcy during the fourth quarter of 2001;

- a $57 million decrease in operating losses from our Retail Energy segment;

- a $37 million net gain resulting from the settlement of an indemnity agreement related to certain energy obligations entered into in connection with our acquisition of Reliant Energy Power Generation Benelux N.V. (REPGB), formerly N.V. UNA;

- a $51 million gain recorded in equity income in 2001 related to a preacquisition contingency for the value of NEA B.V. (NEA), the coordinating body for the Dutch electricity generating sector, which is an equity investment in which REPGB holds a 22.5% economic interest;

- a $184 million decrease in net interest expense related to debt with affiliated companies; and

- a $27 million pre-tax impairment loss on marketable equity securities classified as "available-for-sale" in 2000.

The above items were partially offset by:

- a $66 million decrease in European Energy's gross margins, primarily attributable to the Dutch wholesale electric market opening to competition on January 1, 2001, excluding the impact of a $17 million provision related to energy sales to Enron recorded in the fourth quarter of 2001;

- a $100 million pre-tax, non-cash charge relating to the redesign of some of Reliant Energy's benefit plans in anticipation of our separation from Reliant Energy;

- an $85 million pre-tax provision related to energy sales to Enron which was recorded in the fourth quarter of 2001;

- $54 million in pre-tax disposal charges and impairments of goodwill and fixed assets related to the exiting of our Communications business;

- a $37 million decrease in our Wholesale Energy segment's equity earnings of unconsolidated subsidiaries in 2001 as compared to 2000; and

- an $18 million pre-tax gain in 2000 on the sale of our interest in one of our development-stage electric generation projects.

Operating Income. For an explanation of changes in our operating income and margins, please read the discussion below of operating income (loss) by segment.

Other Income/Expense. We incurred net other income of $64 million during 2001 compared to net other expense of $147 million in 2000. The increase in other income of $211 million in 2001 as compared to 2000 resulted primarily from the following:

- a $184 million decrease in interest expense on debt owed to affiliated companies;

- a $51 million gain recorded in equity income with respect to our equity investment in NEA;

- a $27 million pre-tax impairment loss on marketable equity securities classified as "available-for-sale" in 2000;

- a $12 million net increase in holding gains from investments in 2001, including an $18 million increase in realized holding gains from equity and debt securities and a $1 million increase in unrealized holding gains from equity and debt securities partially offset by (a) a decrease of $1 million in realized gains by our Other Operations segment resulting from reduced cash distributions from venture capital investments, (b) a $2 million impairment of investments and (c) a $4 million decrease in foreign exchange gains on financial instruments; and

- a $9 million increase in interest income in 2001 earned by our European Energy segment related to interest receivable on our claims pursuant to an indemnity for certain energy obligations and the related settlement and by our Wholesale Energy segment on restricted deposits related to our energy trading activities and on collateral related to electric generation equipment.

The $184 million decrease in interest expense on debt owed to affiliated companies, net of interest expense capitalized on projects, in 2001 as compared to 2000 is primarily due to the following:

- the conversion into equity of $1.7 billion of debt owed to Reliant Energy and its subsidiaries in connection with the completion of the IPO in May 2001;

- the repayment in August 2000 of $1.0 billion of debt owed to Reliant Energy related to our Mid-Atlantic acquisition, which is included in our Northeast region operations, from proceeds received from the generating facilities' sale-leaseback transactions; and

- the advancing of excess cash primarily resulting from the IPO to a subsidiary of Reliant Energy.

The increase in other income noted above was partially offset by:

- o 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;

- o an $18 million pre-tax gain in 2000 on the sale of our interest in one of our development-stage electric generation projects; and

- o a $37 million decrease in our Wholesale Energy segment's equity earnings of unconsolidated subsidiaries in 2001 as compared to 2000.

Our Wholesale Energy segment reported income from equity investments in 2001 of $6 million 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.

During the second quarter of 2001, we recorded a $51 million gain 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. Pursuant to the purchase agreement of REPGB, as

amended, REPGB was entitled to a $51 million (NLG 125 million) dividend from NEA with any remainder owed to the former shareholders of REPGB. In December 2001, REPGB entered into a settlement agreement resolving its former shareholders' stranded cost indemnity obligations. Under the settlement agreement, the former shareholders waived all rights to claim distributions from NEA. For further information regarding the settlement agreement, please read the European Energy segment's operating income analysis below and Note 13(f) to our consolidated financial statements.

During 2000, we incurred a pre-tax impairment loss of $27 million on marketable equity securities classified as "available-for-sale" by Other Operations. Management's determination to recognize this impairment resulted from a combination of events occurring in 2000 related to this investment. Such 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 to be other than temporary. During 2001, we recognized a pre-tax gain of $14 million from the sale of a portion of this investment. For additional discussion of this investment, please read Note 2(m) to our consolidated financial statements.

Income Tax Expense. We calculate our income tax provision on a separate return basis under a tax sharing agreement with Reliant Energy. Our deferred income taxes are calculated using the liability method of accounting, which measures deferred income taxes for all significant income tax temporary differences. Our current federal and some state income taxes are payable to or receivable from Reliant Energy. Our federal statutory tax rate is 35%. During 2001 and 2000, our effective tax rate was 32.9% and 30.4%, 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. In 2001 and prior years, under Dutch corporate income tax laws, the earnings of REPGB were subject to a zero percent Dutch corporate income tax rate as a result of the Dutch tax holiday applicable to its electric industry. In 2002, all of European Energy's earnings in the Netherlands will be subject to the standard Dutch corporate income tax rate, which currently is 34.5%.

Subsequent to the Distribution, we will cease to be a member of the Reliant Energy consolidated tax group. This separation could have future income tax implications for us. Our separation from the Reliant Energy consolidated tax group will change 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 Reliant Energy 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 Reliant Energy consolidated tax group subject to Reliant Energy's consent and any existing statutory carryback limitations. Reliant Energy has agreed not to unreasonably withhold such consent.

As discussed in Note 13(f) to our consolidated financial statements, 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 an out-of-market gas supply contract and three out-of-market electricity contracts. REPGB's allocated share of these liabilities is 22.5%. As a result, we recorded a 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. We believe that the costs incurred by REPGB subsequent to the tax holiday ending in 2001 related to these contracts will be deductible for Dutch tax purposes. However, due to uncertainties related to the deductibility of these costs, we have recorded an offsetting liability in other liabilities in our consolidated financial statements of $127 million as of December 31, 2001.

2000 COMPARED TO 1999

Net Income. We reported consolidated net income of $210 million for 2000 compared to consolidated net income of $24 million for 1999. The 2000 results included an extraordinary gain of $7 million related to the early extinguishment of $272 million of long-term debt, which gain is further described in Note 8(b) to our consolidated financial statements.

Our consolidated net income, before the extraordinary gain, was $203 million for 2000 compared to consolidated net income of $24 million for 1999. The $179 million increase in 2000 compared to 1999 was primarily due to increased earnings from our Wholesale Energy segment, the inclusion of earnings from the Mid-Atlantic generating assets, which our Wholesale Energy segment acquired in May 2000, and the inclusion of earnings from our European Energy segment, which was established in the fourth quarter of 1999 with the acquisition of REPGB. The Mid-Atlantic generating assets and European Energy segment contributed $212 million and $84 million, respectively, to operating income for 2000. For additional information on the acquisition of the

Mid-Atlantic generating assets and REPGB, please read Notes 5(a) and 5(b) to our consolidated financial statements. The increases in 2000 earnings compared to 1999 earnings from our Wholesale Energy and European Energy segments were partially offset by increased losses from our Retail Energy and Other Operations segments over the same period.

Operating Income. For an explanation of changes in our operating income, please read the discussion below of operating income (loss) by segment.

Other Income/Expense. We incurred net other expense of $147 million for 2000 compared to net other income of $12 million for 1999. The increase in expense of $159 million in 2000 as compared to 1999 resulted primarily from a pre-tax impairment loss of $27 million on marketable equity securities classified as "available-for-sale" incurred in 2000 by Other Operations, increased net interest expense on obligations to Reliant Energy and its subsidiaries of $162 million and increased interest expense on obligations to third parties of $33 million, each net of interest capitalized on construction projects. Increased interest expense resulted primarily from higher levels of debt during 2000 compared to 1999. Increased debt levels were primarily associated with borrowings for the funding of the acquisition of REPGB in the fourth quarter of 1999 and the first quarter of 2000, the acquisition of our Mid-Atlantic generating facilities in the second quarter of 2000, capital expenditures and increased margin deposits on energy trading and hedging activities. In 2000, we had a decrease of $12 million in unrealized holding gains from debt and equity securities classified as "trading," a $3 million increase in foreign exchange gains on financial instruments and a $3 million increase in realized gains by our Other Operations segment primarily as a result of increased cash distributions from venture capital investments.

The increased net other expense noted above was partially offset by:

o an $18 million pre-tax gain in 2000 on the sale of our interest in one of our development-stage electric generation projects,

o a $18 million increase in interest income in 2000 earned on increased deposits primarily related to our Wholesale Energy segment,

o a $22 million increase in equity earnings in unconsolidated subsidiaries in 2000, and

o a $7 million option premium expense recorded in 1999 to economically hedge foreign currency risks for our REPGB purchase obligation.

Our Wholesale Energy segment reported income from equity investments in 2000 of $43 million compared to equity losses of $1 million in 1999. The equity income in 2000 primarily resulted from an investment in an electric generation plant in Boulder City, Nevada. The plant became operational in May 2000. In 1999, we recorded $22 million in equity income related to REPGB for the period from October 1, 1999 through November 30, 1999. For additional information about the REPGB acquisition, including our accounting treatment, please read Note 5(b) to our consolidated financial statements.

Income Tax Expense. During 2000 and 1999, our effective tax rate was 30.4% and 9.6%, respectively. Our reconciling items from the federal statutory tax rate to the effective tax rate totaled $13 million for 2000. 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. Our reconciling items from the federal statutory tax rate to the effective tax rate totaled $7 million for 1999. These items primarily related to income earned by REPGB and were partially offset by nondeductible goodwill and valuation allowances.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (loss) for each of our business segments for 1999, 2000 and 2001.

	OPERATING INCOME (LOSS) BY BUSINESS SEGMENT		
	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
	(IN MILLIONS)		
Wholesale Energy	$ 19	$ 485	$ 899
European Energy	12	84	56
Retail Energy	(13)	(70)	(13)
Other Operations	(4)	(61)	(180)
Total Consolidated	$ 14	$ 438	$ 762

WHOLESALE ENERGY

Our Wholesale Energy segment includes our non-rate regulated power generation operations in the United States and our wholesale energy trading, marketing, origination and risk management operations in North America.

As of December 31, 2001, we owned or leased electric power generation facilities with an aggregate net generating capacity of 11,109 megawatts (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, 2001, we had 3,587 MW of additional net generating capacity under construction, including facilities having 2,120 MW that are being constructed under a construction agency agreement by off-balance sheet special purpose entities. 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. 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. For additional information regarding this acquisition of our Mid-Atlantic generating assets completed in May 2000 by Wholesale Energy, including the accounting treatment of this acquisition, please read Note 5(a) to our consolidated financial statements.

On February 19, 2002, we acquired all of the outstanding shares of common stock of Orion Power Holdings, Inc. (Orion Power) for $26.80 per share in cash for an aggregate purchase price of $2.9 billion. As of February 19, 2002, Orion Power's debt obligations were $2.4 billion ($2.1 billion net of cash acquired, some of which is restricted pursuant to debt covenants). Orion Power is an independent electric power generating company that was formed in March 1998 to acquire, develop, own and operate power-generating facilities in certain deregulated wholesale markets in North America. As of February 28, 2002, Orion Power had 81 power plants in operation with a total generating capacity of 5,644 MW and an additional 804 MW under construction or in various stages of development.

For a discussion of the factors that may affect the future results of operations of Wholesale Energy, please read " - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Wholesale Energy Operations."

The following table provides summary data regarding the results of operations of Wholesale Energy for 1999, 2000 and 2001.

	WHOLESALE ENERGY		
	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
	(IN MILLIONS, EXCEPT OPERATING DATA)		
Operating Revenues	$ 6,449	$ 18,072	$ 29,742
Operating Expenses:			
Fuel and cost of gas sold	3,548	10,295	14,834
Purchased power	2,688	6,775	13,300
Operation and maintenance	92	237	349
General, administrative and development	81	172	242
Depreciation and amortization	21	108	118
Total Operating Expenses	$ 6,430	$ 17,587	$ 28,843
Operating Income	$ 19	$ 485	$ 899
Operating Data:			
Net Generation Capacity (MW)	4,469	9,231	11,109
Electricity Wholesale Power Sales (MMWh)(1)	82	172	300
Natural Gas Sales (Bcf)(2)	1,564	2,423	3,508

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(1) Million megawatt hours.

(2) Billion cubic feet.

2001 Compared to 2000. Wholesale Energy's operating income increased by $414 million in 2001 compared to 2000. 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 provision and a $12 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.

The increase in operating income was primarily due to increased gross margins. Gross margins for Wholesale Energy increased by $606 million primarily due to increased volumes on power sales from our generation facilities, increased volumes from our trading and marketing activities and the addition of our Mid-Atlantic assets and strong commercial and operational performance in other regions. Margins on power sales from our generation facilities, excluding a $63 million provision related to Enron, increased by $429 million in the West region (Arizona, California and portions of New Mexico and Nevada), $85 million in the Mid-Atlantic region, and $32 million in other regions in 2001 compared to 2000. 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, and we do not expect them to return in 2002. Trading and marketing gross margins, excluding a $5 million provision related to Enron, increased $113 million from $197 million in 2000 to $310 million in 2001 primarily as a result of increased natural gas trading volumes. These results were partially offset by the $68 million provision related to Enron as discussed above, higher operation and maintenance expenses from facilities in the Mid-Atlantic region acquired in 2000, higher general and administrative expenses and increased depreciation expense.

The following table provides further summary data regarding gross margin by commodity of Wholesale Energy for 2000 and 2001.

	YEAR ENDED DECEMBER 31,	
	2000	2001
	(IN MILLIONS)	
Gas revenues	$ 9,326	$ 13,799
Power revenues	8,666	15,931
Other commodity revenues	80	80
Credit provision related to Enron	--	(68)
Total revenues	18,072	29,742
Cost of gas sold	9,213	13,571
Fuel and purchased power	7,770	14,499
Other commodity costs	87	64
Total cost of sales	17,070	28,134
Gross margin	$ 1,002	$ 1,608

Wholesale Energy's revenues increased by $11.7 billion (65%) in 2001 compared to 2000. The increased revenues were primarily due to increased volumes for natural gas (approximately $4.2 billion) and power sales (approximately $6.6 billion) and to a lesser extent increased prices for power sales compared to 2000, which increased approximately $0.7 billion. Wholesale Energy's fuel and cost of gas sold and purchased power increased by $11.1 billion in 2001 compared to 2000, largely due to increased volumes for natural gas and power sales and to a lesser extent increases in power generation plant output, which increased approximately 33% compared to 2000, and increased prices for power purchases.

Operation and maintenance expenses for Wholesale Energy increased $112 million in 2001 compared to the same period in 2000, primarily due to costs associated with the operation and maintenance of generating plants acquired in the Mid-Atlantic region of $53 million and higher lease expense of $38 million associated with the Mid-Atlantic generation facilities' sale-leaseback transactions that were entered into in August 2000. The higher lease expense associated with the Mid-Atlantic generating facilities was offset by lower interest expense in the consolidated results of operations in 2001 compared to 2000. General, administrative and development expenses increased $70 million in 2001 compared to 2000, primarily due to higher administrative costs to support growing wholesale commercial activities of $69 million and higher legal and regulatory expenses related to the West region of $25 million, partially offset by decreased development expenses of $12 million. 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 a decrease in amortization of our air emissions regulatory allowances of $8 million.

2000 Compared to 1999. Wholesale Energy's operating income increased $466 million for 2000 compared to 1999. The increase was primarily due to increased energy sales volumes, higher prices for energy and ancillary services, and improved operating results from trading and marketing activities, as well as expansion of our generation operations into regions other than the Western United States, including the Mid-Atlantic United States, Florida and Texas.

Wholesale Energy's operating revenues increased $11.6 billion (180%) for 2000 compared to 1999. The increase was primarily due to an increase in prices and volumes for both gas and power sales in 2000 compared to 1999. Wholesale Energy's fuel and cost of gas sold and purchased power costs increased $6.7 billion and $4.1 billion, respectively, in 2000 compared to 1999. The increase in fuel and cost of gas sold was primarily due to an increase in gas volumes purchased, and to increases in plant output and in the price of gas. The increase in purchased power cost was primarily due to a higher average cost of power and higher power volumes purchased. Operation and maintenance expenses and general, administrative and development expenses increased $145 million and $91 million, respectively, in 2000 compared to 1999. These increases were primarily due to costs associated with the maintenance of facilities acquired or placed into commercial operation during the period, lease expense associated with the Mid-Atlantic generating facilities sale-leaseback transactions, higher run rates at existing facilities, increased costs associated with developing new power generation projects and higher staffing levels to support increased sales and expanded trading and marketing efforts. Depreciation and amortization expense for 2000 increased $87 million as compared to 1999, primarily as a result of our acquisition of the Mid-Atlantic generating facilities and other generating facilities in 2000.

EUROPEAN ENERGY

Our European Energy segment includes the operations of REPGB and its subsidiaries and our European trading and power origination operations. We created European Energy in the fourth quarter of 1999 with the acquisition of REPGB and the formation of our European trading and power origination operations. European Energy generates and sells power from its generation facilities in the Netherlands and participates in the emerging wholesale energy trading markets in Northwest Europe.

Effective October 7, 1999, we acquired REPGB, a Dutch generation company, for a net purchase price of $1.9 billion. Our 1999 consolidated financial statements reflect REPGB's results of operations for the period from October 1, 1999 through November 30, 1999 under the equity method of accounting rather than under the consolidation method. Subsequent to December 1, 1999, we have consolidated 100% of REPGB's operating results. For additional information regarding the acquisition of REPGB and the related accounting treatment, please read Note 5(b) to our consolidated financial statements.

In connection with our evaluation of the acquisition of REPGB, we also began to assess and formulate an employee severance plan to be undertaken as soon as reasonably possible post-acquisition. The intent of this plan

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was to make REPGB competitive in the Dutch electricity market when it became deregulated on January 1, 2001. This plan was finalized, approved and completed in September 2000. At that time, we recorded the severance liability as a purchase price adjustment in the amount of $19 million. During 2001, we utilized $8 million of the reserve. As of December 31, 2001, the remaining severance liability is $11 million.

REPGB and the other major Dutch generators historically operated under a protocol agreement, pursuant to which the generators provided capacity and energy to distributors in exchange for regulated production payments, plus compensation for actual fuel expended in the production of electricity over the period from 1997 through 2000. Effective January 1, 2001, these agreements expired in all material aspects. Beginning January 1, 2001, the Dutch wholesale electric market was opened to competition. Consistent with our expectations at the time that we made the acquisition, REPGB experienced a significant decline in electric margins in 2001 attributable to the deregulation of the wholesale electric market.

In 2001, we evaluated strategic alternatives for our European Energy segment, including a possible sale. We completed our evaluation, and determined that given current market conditions and prices, it is not advisable to sell our European Energy operations. Consequently, we decided to continue to own and operate our European Energy segment and to expand our trading and origination activities in Northwest Europe. During December 2001, we evaluated our European Energy segment's long-lived assets and goodwill for impairment. 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. As of December 31, 2001, pursuant to SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," no impairment has been indicated. For assessing of impairment in 2002 under SFAS No. 142 "Goodwill and Other Intangible Assets," please read " - New Accounting Pronouncements and Critical Accounting Policies" below.

For additional information regarding these and other factors that may affect the future results of operations of European Energy, please read " -

Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our European Energy Operations."

For information regarding foreign currency matters, please read Note 6(b) to our consolidated financial statements and "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A of this Form 10-K.

The following table provides summary data for the results of operations of our European Energy segment for the three months ended December 31, 1999 and the years ended December 31, 2000 and 2001.

	EUROPEAN ENERGY		
	THREE MONTHS ENDED DECEMBER 31,	YEAR ENDED DECEMBER 31,	
	1999	2000	2001
	(IN MILLIONS, EXCEPT OPERATING DATA)		
Operating Revenues	$ 56	$ 580	$ 1,192
Operating Expenses:			
Fuel	24	260	400
Purchased power	--	34	589
Operation and maintenance	8	87	30
General and administrative	6	39	41
Depreciation and amortization	6	76	76
Total Operating Expenses	$ 44	$ 496	$ 1,136
Operating Income	$ 12	$ 84	$ 56
Operating Data:			
Net Generation Capacity (MW)	3,476	3,476	3,476
Electric Sales (MMWh)	3	13	42

2001 Compared to 2000. European Energy's operating income decreased by $28 million for 2001 compared to 2000. This decrease was primarily due to the anticipated decline in electric power generation gross margins (revenues less fuel and purchased power), as the Dutch electric market was completely opened to wholesale competition on January 1, 2001. 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. Increased margins from ancillary services of $33 million and district heating sales of $9 million in 2001 compared to 2000 and efficiency and energy payments from NEA totaling $30 million in 2001 partially offset this decline. Trading gross margins decreased $12 million from a $3 million gross margin in 2000 to a $9 million gross margin loss in 2001 primarily as a result of a $17 million provision against receivable and trading and marketing asset balances related to Enron.

Excluding this provision, trading gross margins increased primarily due to a significant increase in power trading volumes, trading origination transactions and increased volatility in the Dutch and German markets. In addition, the decrease in operating income was partially offset by a $37 million net gain related to the settlement of an indemnity agreement with the former shareholders of REPGB in the fourth quarter of 2001, as discussed below.

European Energy's operating revenues increased by $612 million for 2001 compared to 2000. The increase was primarily due to increased trading revenues in the Dutch, German and Austrian power markets of $544 million and, to a lesser extent, increased volumes of electric generation sales, which increased 41%, partially offset by a 29% decrease in prices for power sales. Fuel and purchased power costs increased $695 million for 2001 compared to 2000 primarily due to increased purchased power for trading activities, and to a lesser extent increased cost of natural gas due to higher gas prices, increased output from our generating facilities and increased transmission and grid charges as a result of a change in the tariff structure.

Operation and maintenance and general and administrative expenses decreased by $55 million for 2001 compared to 2000. These expenses declined primarily due to (a) the net gain of $37 million recorded in operation expenses related to the settlement of the former shareholders' indemnity obligation, as discussed below, (b) 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 (c) decreases in provisions for environmental liabilities, employee benefits and other accruals totaling $6 million. This decrease was partially offset by an increase in personnel and operating expenses related to our trading operations, facilities costs and systems upgrades.

In December 2001, REPGB and its former shareholders entered into a settlement agreement resolving the former shareholders' stranded cost indemnity obligations under the purchase agreement of REPGB. During the fourth quarter of 2001, we recognized a net settlement gain of $37 million in operation expenses for the difference between the sum of (a) the cash settlement consideration of $202 million, and REPGB's rights to claim future distributions of our NEA investment of an estimated $248 million and (b) 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 costs incurred in 2001 of $44 million both previously recorded in our consolidated balance sheet. Future changes in the valuation of the stranded cost import contracts that remain an obligation of REPGB will be recorded as adjustments to our consolidated statement of income, thus introducing potential earnings volatility. For additional information regarding the settlement, please read Note 13(f) to our consolidated financial statements.

2000 Compared to 1999. For the year ended December 31, 2000, European Energy reported operating income of $84 million. European Energy reported operating income of $12 million for the three months ended December 31, 1999. In 1999, we recorded $22 million in equity income related to REPGB for the period from October 1, 1999 through November 30, 1999.

RETAIL ENERGY

Our Retail Energy segment provides energy products and services to end-use customers, ranging from residential and small commercial customers to large commercial, institutional and industrial customers. In addition, Retail Energy provided billing, customer service, credit and collection and remittance services to Reliant Energy's regulated electric utility and two of its natural gas distribution divisions. The service agreement governing these services terminated on December 31, 2001. Retail Energy charged the regulated electric and natural gas utilities for these services at cost. We acquired approximately 1.7 million electric retail customers in the Houston metropolitan area when the Texas market opened to competition in January 2002. During the first half of 2002, the Texas electric retail market will be largely focused on the extensive efforts necessary to transition customers from the utilities to the affiliated retail electric providers. We expect to expand our marketing efforts for small residential and

commercial customers (i.e., customers with an aggregate peak demand at or below one MW) to other areas in Texas outside of the Houston territory during the second quarter of 2002. We signed 246 contracts with large commercial, industrial and institutional (e.g., hospitals, universities, school systems and government agencies) customers (i.e., customers with an aggregate peak demand of more than one MW) during 2001, with an aggregate peak electric energy demand of approximately 3,700 MW and serving approximately 12,000 meter locations. These customers are both in the Houston metropolitan area as well as outside of the Houston territory. Our marketing efforts for large commercial, industrial and institutional customers are continuing throughout the competitive region of the Electric Reliability Council of Texas (ERCOT).

For a discussion of the factors that may affect the future results of operations of Retail Energy, please read " - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Operations of Our Retail Energy Operations."

The following table provides summary data regarding the results of operations of Retail Energy for 1999, 2000 and 2001.

	RETAIL ENERGY		
	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
	(IN MILLIONS)		
Operating Revenues	$ 34	$ 64	$ 211
Operating Expenses:			
Purchased power	--	--	27
Operation and maintenance	35	101	110
General and administrative	12	29	76
Depreciation and amortization	--	4	11
Total Operating Expenses	$ 47	$ 134	$ 224
Operating Loss	$ (13)	$ (70)	$ (13)

2001 Compared to 2000. Our Retail Energy segment's operating loss decreased by $57 million for 2001 compared to 2000. The operating loss reduction was primarily due to increased sales of energy and energy services to commercial, industrial and institutional customers, 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 are accounted for under the mark-to-market method of accounting. These energy contracts are recorded at fair value in revenue upon contract execution. The net changes in their market values are 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 increased by $147 million for 2001 compared to 2000 largely due to increased revenues from sales of energy and energy services to large commercial, industrial and institutional customers, as well as increased revenues for the billing and remittance services provided to Reliant Energy. Purchased power expenses increased by $27 million in 2001 primarily due to a $22 million increase in wholesale electricity purchases and a $5 million increase in the cost of transmission service both related to the Texas retail pilot program during the last half of 2001. Our Wholesale Energy segment purchases and manages Retail Energy's wholesale purchased power requirements needed to fulfill its retail energy commitments. The Wholesale Energy segment charges Retail Energy for the purchased power at its actual cost and charges an administrative fee for such service.

Operations and maintenance costs increased by $9 million and general and administrative expenses increased $47 million in 2001 as compared to 2000, primarily due to 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 totaling $35 million and increased costs incurred in performing billing, customer service, credit and collections and remittance service for Reliant Energy of $31 million.

2000 Compared to 1999. Retail Energy's operating loss increased $57 million for 2000 compared to 1999. Operating revenues increased $30 million (88%) for 2000 as compared to 1999. This increase was primarily the result of the inclusion of revenues generated by the operations acquired during November 1999, additional revenue generated by an increase in the number of new energy service contracts and additional revenues for the billing and remittance services provided to Reliant Energy. For 2000 as compared to 1999, operations and maintenance costs increased $66 million and general and administrative costs increased $17 million. Increased operation and maintenance costs resulted primarily from costs associated with servicing contracts acquired during 1999 as well as new contracts entered into in 2000, costs incurred in performing billing, customer service, credit and collection and remittance services for Reliant Energy, and costs related to building an infrastructure necessary to prepare for competition in the retail electric market in Texas. General and administrative costs increased as a result of building the infrastructure necessary to prepare for competition in the retail electric market in Texas. In addition, during the fourth quarter of 2000, we incurred an obligation to pay $12 million in order to secure the naming rights to a Houston sports complex and for the initial advertising of which $10 million was expensed in 2000. Starting in 2002, when the new stadium in the sports complex is operational, we will pay $10 million each year through 2032 for annual advertising associated with the sports complex.

OTHER OPERATIONS

Our Other Operations segment includes the operations of our venture capital and Communications businesses, 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 owns 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 for the results of operations for Other Operations for 1999, 2000 and 2001.

	OTHER OPERATIONS		
	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
		(IN MILLIONS)	
Operating Revenues	$ --	$ 6	$ 11
Operating Expenses:			
Operation and maintenance	--	9	21
General and administrative	2	52	128
Depreciation and amortization	2	6	42
Total Operating Expenses	$ 4	$ 67	$ 191
Operating Loss	$ (4)	$ (61)	$ (180)

2001 Compared to 2000. Other Operation's operating loss increased by $119 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 non-cash charge of $100 million during 2001 relating to the redesign of some of Reliant Energy's benefit plans in anticipation of our separation from Reliant Energy. These items were partially offset by decreased corporate operating expenses of $12 million and decreased charitable contributions of $15 million of equity securities classified as "trading" to a charitable foundation. For additional information about the benefit charge noted above, please read Notes 11(b) and 11(d) 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 severance accruals, lease cancellation costs and other incremental costs associated with exiting the Communications business, totaling $13 million. The goodwill and fixed asset impairments are included in depreciation and amortization expense.

In connection with our anticipated separation from Reliant Energy, we expect to record in the quarter in which the Distribution is completed, a pre-tax net loss of approximately $36 million related to the settlement of pension and post retirement obligations for former employees of Reliant Energy, who transferred to us.

2000 Compared to 1999. During 2000, Other Operations had operating revenues of $6 million primarily from its Communications business, which was formed in June 1999. General and administrative and operation and maintenance costs in 2000 of $61 million, compared to $2 million for 1999, resulted primarily from costs related to our Communications business and a $15 million non-cash contribution of equity securities, as discussed above. The increase in depreciation and amortization of $4 million is primarily related to increased capital expenditures in 2000 as compared to the same period in 1999.

TRADING AND MARKETING OPERATIONS

We trade and market power, natural gas and other energy-related commodities and provide related risk management services to our customers. We apply mark-to-market accounting for all of our non-asset based energy trading, marketing, power origination and risk management services activities. For information regarding mark-to-market accounting, please read Notes 2(d) and 6 to our consolidated financial statements. These trading and marketing activities consist of:

- the domestic energy trading, marketing, power origination and risk management services operations of our Wholesale Energy segment;
- the European energy trading and power origination operations of our European Energy segment; and
- the large contracted commercial, industrial and institutional retail electricity business of our Retail Energy segment.

Our domestic and European energy trading and marketing operations enter into derivative transactions as a means of optimization of our current power generation asset position and to take a market position. For additional information regarding the types of contracts and activities of our trading and marketing operations, please read "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K and Note 6 to our consolidated financial statements.

Below is a detail of our net trading and marketing assets (liabilities) by segment:

	AS OF DECEMBER 31,	
	2000	2001
	(IN MILLIONS)	
Wholesale Energy	$ 31	$ 154
European Energy	1	(9)
Retail Energy	--	73
Net trading and marketing assets and liabilities	$ 32	$ 218

Our trading and marketing and risk management services margins realized and unrealized are as follows:

	FOR THE YEAR ENDED DECEMBER 31,	
	2000	2001
	(IN MILLIONS)	
Realized	$ 202	$ 184
Unrealized	(2)	186
Total	$ 200	$ 370

Below is an analysis of our net trading and marketing assets and liabilities for 2001 (in millions):

Fair value of contracts outstanding at December 31, 2000	$
Fair value of new contracts when entered into during the year	
Contracts realized or settled during the year	
Changes in fair values attributable to changes in valuation techniques and assumptions	
Changes in fair values attributable to market price and other market changes	
Fair value of contracts outstanding at December 31, 2001	$

During 2001, our Retail Energy segment entered into contracts with large commercial, industrial and institutional customers, with a peak demand of approximately 3,700 MW, ranging from one to three years. These contracts had an aggregated fair value of $97 million at the contract inception dates. Subsequent to the inception dates, the fair values of these contracts were adjusted to $74 million due to changes in assumptions used in the valuation models, as described below. The fair value of these Retail Energy electric supply contracts was determined by comparing the contractual pricing to the estimated market price for the retail energy delivery and applying the estimated volumes under the provisions of these contracts. This calculation involves estimating the customer's anticipated load volume, and using the forward ERCOT over-the-counter (OTC) commodity prices, adjusted for the customer's anticipated load pattern. 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. In addition, some estimates include anticipated delivery costs, such as regulatory and transmission charges, electric line losses, ERCOT system operator administrative fees and other market interaction charges, estimated credit risk and administrative costs to serve. The weighted-average duration of these transactions is approximately one year.

The remaining fair value of new contracts recorded at inception of $22 million primarily relates to Wholesale Energy fixed and variable-priced power purchases and sales. 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. A significant portion of the value of these contracts required utilization of internal models. For the contracts extending beyond December 31, 2001, the weighted-average duration of these transactions is less than two years.

Below are the maturities of our contracts related to our trading and marketing assets and liabilities as of December 31, 2001 (in millions):

	FAIR VALUE OF CONTRACTS AT DECEMBER 31, 200				
SOURCE OF FAIR VALUE	2002	2003	2004	2005	2006
Prices actively quoted	$ (43)	$ 4	$ 1	$ --	$
Prices provided by other external sources	142	58	(5)	(3)	
Prices based on models and other valuation methods	34	(1)	3	3	
Total	$ 133	$ 61	$ (1)	$ --	$

The "prices actively quoted" category represents our New York Mercantile Exchange (NYMEX) futures positions in natural gas and crude oil. As of December 31, 2001, the NYMEX had quoted prices for natural gas and crude oil for the next 36 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 60 and 36 months into the future, respectively. We value these positions against internally developed forward market price curves that are continuously compared to 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 actively quoted. Options are typically valued using Black-Scholes option valuation models.

Although the valuation of the simple structures might not be different than 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 have 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 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 for further discussion and measurement of the market exposure in the trading and marketing businesses and discussion of credit risk management.

For additional information about price volatility and our hedging strategy, please read " - 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 information regarding our counterparty credit risk, including credit ratings, exposure and collateral held by us, please read, "Quantitative and Qualitative Disclosures About Market Risk - Credit Risk" in Item 7A of this Form 10-K.

For a description of accounting policies for our trading and marketing activities, please read Notes 2(d) and 6 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, please read "Quantitative and Qualitative Disclosures About Market Risk - Risk Management Structure" in Item 7A of this Form 10-K.

RELATED-PARTY TRANSACTIONS

In the normal course of operations and in anticipation of our separation from Reliant Energy, we have entered into transactions and agreements with related parties, including Reliant Energy. For a discussion of historical related party transactions, please read Note 3 to our consolidated financial statements. Below are details of significant current related party transactions, arrangements and agreements.

AGREEMENTS BETWEEN RELIANT ENERGY AND RELIANT RESOURCES

Master Separation Agreement. Shortly before the IPO, we entered into the Master Separation Agreement with Reliant Energy. The Master Separation Agreement provides for the separation of our assets and businesses from those of Reliant Energy. It also contains agreements governing the relationship between us and Reliant Energy after the IPO, and in some cases after the Distribution, and specifies the related ancillary agreements that we have signed with Reliant Energy, some of which are described in further detail below.

The Master 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 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 Reliant Energy's other businesses with Reliant Energy 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.

Genco Option Agreement. In connection with the separation of our businesses from those of Reliant Energy, Reliant Energy has granted us an option to purchase, subject to completion of the Distribution, all of the shares of capital stock owned by Reliant Energy in January 2004 of an entity (Texas Genco) that will hold the Texas generating assets of Reliant Energy's electric utility division. For additional information regarding the Texas Genco option and various agreements between Reliant Energy and us related to the Texas Genco option, please read Note 4(b) to our consolidated financial statements.

Service Agreements. We have entered into agreements with Reliant Energy under which Reliant Energy 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 and payroll, office support services and purchasing and logistics. The charges we will pay Reliant Energy for these services are generally intended to allow Reliant Energy to recover its fully allocated costs of providing the services, plus out-of-pocket costs and expenses. In addition, pursuant to lease agreements, Reliant Energy 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, please read Note 4(a) to our consolidated financial statements.

Payment to Reliant Energy. To the extent that our price for providing retail electric service to residential and small commercial customers in Reliant Energy's Houston service territory during 2002 and 2003, which price is mandated by the Texas electric restructuring law, exceeds the market price of electricity, we may be required to make a payment to Reliant Energy in early 2004 unless the Texas Utility Commission determines that, 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 Reliant Energy's electric utility's Houston service territory as of January 1, 2002 is committed to be served by retail electric providers other than us. For additional information regarding this payment, please read Note 13(g) to our consolidated financial statements.

Guarantee of Certain Benefit Payments. We have guaranteed, in the event Reliant Energy becomes insolvent, certain non-qualified benefits of Reliant Energy's and its subsidiaries' existing retirees at the Distribution totaling approximately $55 million.

Transportation Agreement. Prior to the IPO, Reliant Energy Services entered into an agreement whereby a subsidiary of Reliant Energy 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, please read Note 13(b) to our consolidated financial statements.

Commodity Risk Hedges Entered Into by Us on Behalf of Subsidiaries of Reliant Energy. Reliant Energy Services enters into derivative instruments on behalf of affiliated entities within the Reliant Energy consolidated group in accordance with Reliant Energy's risk management policies. Historically, Reliant Energy Services was subject to the related counterparty credit risk. During 2001, related to the Enron bankruptcy, we recognized a $6 million loss related to such transactions.

Various Other Agreements. In connection with the separation of our businesses from those of Reliant Energy, 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 Reliant Energy 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, please read Note 4(c) to our consolidated financial statements.

COMMON DIRECTORS ON RELIANT RESOURCES' AND RELIANT ENERGY'S BOARD OF DIRECTORS

Three of our directors are also directors of Reliant Energy. One of these directors is our chairman, president and chief executive officer. These directors owe fiduciary duties to the stockholders of each company. As a result, in connection with any transaction or other relationship involving both companies, these directors may need to recuse themselves and not participate in any board action relating to these transactions or relationships. It is anticipated that at the time of the Distribution, one of these directors will resign as director of Reliant Energy.

CONSTRUCTION AGENCY AGREEMENTS

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. 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. We have guaranteed the performance and payment of our subsidiaries' obligations during the construction periods and, if the lease option is exercised, each lessee's obligations during the lease period. For additional information regarding the construction agency agreements and our generating equipment agreements, please read Note 13(h) to our consolidated financial statements.

CERTAIN FACTORS AFFECTING OUR FUTURE EARNINGS

Our past earnings are not necessarily indicative of our future earnings and results of operations. The magnitude of our future earnings and results of our operations will depend on numerous factors including:

- state, federal and international legislative and regulatory developments, including deregulation, re-regulation and restructuring of the electric utility industry, changes in or application of environmental and other laws and regulations to which we are subject, and changes in or application of laws or regulations applicable to other aspects of our business, such as commodities trading and hedging activities,

- the timing of our separation from Reliant Energy,
- the effects of competition, including the extent and timing of the entry of additional competitors in our markets,
- liquidity concerns in our markets,
- the degree to which we successfully integrate the operations and assets of Orion Power into our Wholesale Energy segment,
- the successful and timely completion of our construction programs, as well as the successful start-up of completed projects,
- our pursuit of potential business strategies, including acquisitions or dispositions of assets or the development of additional power generation facilities,
- the timing and extent of changes in commodity prices and interest rates,
- the availability of adequate supplies of fuel, water, and associated transportation necessary to operate our generation portfolio,
- weather variations and other natural phenomena, which can effect the demand for power from or our ability to produce power at our generating facilities,
- financial market conditions, our access to capital and the results of our financing and refinancing efforts, including availability of funds in the debt/capital markets for merchant generation companies,
- the credit worthiness or bankruptcy or other financial distress of our trading, marketing and risk management services counterparties,
- actions by rating agencies with respect to us or our competitors,
- acts of terrorism or war,
- the availability and price of insurance,

- the reliability of the systems, procedures and other infrastructure necessary to operate our retail electric business, including the systems owned and operated by ERCOT,
- political, legal, regulatory and economic conditions and developments in the United States and in foreign countries in which we operate or into which we might expand our operations, including the effects of fluctuations in foreign currency exchange rates,
- the successful operation of deregulating power markets, and
- the resolution of the refusal by California market participants to pay our receivables balances due to the recent energy crisis in the West region.

In order to adapt to the increasingly competitive environment in our industry, we continue to evaluate a wide array of potential business strategies, including business combinations or acquisitions involving other utility or non-utility businesses or properties, dispositions of currently owned businesses, as well as developing new generation projects, products, services and customer strategies.

FACTORS AFFECTING THE RESULTS OF OUR WHOLESALE ENERGY OPERATIONS

Price Volatility. We sell electricity from our facilities into spot markets under short and long-term contractual arrangements. We are not guaranteed any rate of return on our capital investments through cost of service rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for electricity and fuel in our regional markets. In addition to our power generation operations, we trade and market power. Market prices may fluctuate substantially over relatively short periods of time. Demand for electricity can fluctuate dramatically, creating periods of substantial under- or over-supply. During periods of over-supply, prices are depressed. During periods of under-supply, there is frequently regulatory or political pressure to regulate prices to compensate for product scarcity.

In addition, the FERC, which has jurisdiction over wholesale power rates, as well as independent system operators that oversee some of these markets, have imposed price limitations, bidding rules and other mechanisms to attempt to address some of the volatility in these markets and mitigate market prices. For a discussion of the implementation of price limitations and other rules in the California market, please read Note 13(i) to our consolidated financial statements.

Most of our Wholesale Energy business segment's domestic power generation facilities purchase fuel under short-term contracts or on the spot market. Fuel prices may also be volatile, and the price we can obtain for power sales may not change at the same rate as changes in fuel costs. In addition, we trade and market natural gas and other energy-related commodities. These factors could have an adverse impact on our revenues, margins and results of operations.

Volatility in market prices for fuel and electricity may result from:

- weather conditions,
- seasonality,
- forced or unscheduled plant outages,
- addition of generating capacity,
- changes in market liquidity,
- disruption of electricity or gas transmission or transportation, infrastructure or other constraints or inefficiencies,
- availability of competitively priced alternative energy sources,

- demand for energy commodities and general economic conditions,
- availability and levels of storage and inventory for fuel stocks,

- natural gas, crude oil and refined products, and coal production levels,
- natural disasters, wars, embargoes and other catastrophic events, and
- federal, state and foreign governmental regulation and legislation.

Risks Associated with Our Hedging and Risk Management Activities. To lower our financial exposure related to commodity price fluctuations, our trading, marketing and risk management services operations 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, crude oil and refined products, and other commodities. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sales contracts, futures, financial swaps and option contracts traded in the over-the-counter markets and on exchanges. However, we do not expect to cover the entire exposure of our assets or our positions to market price volatility, 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 and our view on market prices. To the extent we have unhedged positions, fluctuating commodity prices could negatively impact our financial results and financial position. For additional information regarding the accounting treatment for our hedging, trading and marketing and risk management activities, please read Notes 2(d) and 6 to our consolidated financial statements. For additional information regarding the types of contracts and activities of our trading and marketing operations, please read " - Trading and Marketing Operations" and "Qualitative and Quantitative Disclosures about Market Risk" in Item 7A of this Form 10-K.

We manage our power generation hedge objectives in the context of market conditions while targeting certain hedge percentages of future earnings through hedge actions in the current year. As of December 31, 2001, we had hedged 39% and 29% of our planned Wholesale Energy margins for 2002 and 2003, respectively, excluding margins related to Orion Power. Margins for 2002 and 2003 are expected to be positively impacted by the acquisition of Orion Power and negatively affected by lower forward electric power prices as they relate to unhedged positions and an estimated decline in our trading and marketing operations due to projected decreases in volatility in energy commodity markets.

At times, we have open trading positions in the market, within established corporate risk management guidelines, resulting from the management of our trading portfolio. To the extent open trading positions exist, changes in commodity prices could negatively impact our financial results and financial position.

The risk management procedures we have in place may not always be followed or may not always work as planned. As a result of these and other factors, we cannot predict with precision the impact that our risk management decisions may have on our businesses, operating results or financial position. For information regarding our risk management policies, please read "Quantitative and Qualitative Disclosures about Market Risk - Risk Management Structure" in Item 7A to this Form 10-K.

Our trading, marketing and risk management services operations (as well as some of our operations conducted on behalf of Reliant Energy) are also exposed to the risk that counterparties who owe us money or physical commodities, 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. For information regarding our credit risk, including exposure to Enron and utilities in California, please read "Quantitative and Qualitative Disclosure About Market Risk - Credit Risk" in Item 7A of this Form 10-K and Notes 6(d), 13(i) and 17 to our consolidated financial statements.

In the ordinary course of business, and as part of our hedging strategy, we enter into long-term sales arrangements for power, 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, please read Notes 6, 13(a) and 13(c) to our consolidated financial statements.

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Uncertainty in the California Market. 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. Because of the high prices that prevailed during this period, Reliant Energy, and several of our subsidiaries, including Reliant Energy Services and REPG, as well as some of the officers of some of these companies, have been named as defendants in class action lawsuits and other lawsuits filed against a number of companies that own generation plants in California and other sellers of electricity in California markets.

In response to the filing of a number of complaints challenging the level of these wholesale prices, the FERC initiated a staff investigation and issued a number of orders implementing a series of wholesale market reforms and modifications to those reforms. On February 13, 2002, the FERC issued an order initiating a staff investigation into potential manipulation of electric and natural gas prices in the West region for the period January 1, 2000 forward. Some of our long-term bilateral contracts already have been challenged by one of our many counterparties based on the alleged market dysfunction in Western power markets in 2000 and 2001. If these challenges are successful, the precedent set by the challenge could have larger ramifications to our business and operations beyond the challenged contracts at issue. Furthermore, in addition to FERC investigations, several state and other federal regulatory investigations have commenced in connection with the wholesale electricity prices in California and other neighboring Western states to determine the causes of the high prices and potentially to recommend remedial action.

Finally, there have been proposals in the California state legislature to regulate the operations of our California generating subsidiaries, beyond the existing state regulation regarding siting, environmental and other health and safety matters. For additional information regarding the litigation and market uncertainty in California, please read Notes 13(e) and 13(i) to our consolidated financial statements.

Industry Restructuring, the Risk of Re-regulation and the Impact of Current Regulations. The regulatory environment applicable to the United States electric power industry is undergoing significant changes as a result of varying restructuring initiatives at both the state and federal levels and the reassessment of existing regulatory mechanisms stemming from the California power market situation and the bankruptcy of Enron. These initiatives have had a significant impact on the nature of the industry and the manner in which its participants conduct their business. These changes are ongoing and we cannot predict the future development of restructuring in these markets or the ultimate effect that this changing regulatory environment will have on our business.

Moreover, existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us, our facilities or our commercial activities, and future changes in laws and regulations may have a detrimental effect on our business. Some restructured markets, particularly California, have experienced supply problems and price volatility. These supply problems and volatility have been the subject of a significant amount of press coverage, much of which has been critical of the restructuring initiatives. In some markets, including California, proposals have been made by governmental agencies and/or other interested parties to delay or discontinue proposed restructuring or to re-regulate areas of these markets, especially with respect to residential retail customers, that have previously been deregulated. In this connection, state officials, the California Independent System Operator (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 petitions to force entities with market-based rates to return to cost-based rates, some of these proceedings are ongoing and we cannot predict what action the FERC may take on such petitions in the future. If we were forced to adopt cost-based rates, future earnings would be affected. Furthermore, the Cal ISO is undertaking a market redesign process to fundamentally change the structure of wholesale electricity markets and transmission service in California. These changes, if approved by the FERC, could 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. The Cal ISO's stated goal is to complete the first phase of this redesign by September 30, 2002, when the existing FERC market mitigation scheme for California will expire.

On November 20, 2001, the FERC instituted an investigation under Section 206 of the Federal Power Act regarding the tariffs of all sellers with market-based rates authority, including the Company. For information regarding this FERC proceeding and other FERC actions relating to the California market, please read Note 13(i) to

our consolidated financial statements. If the FERC does not modify or reject its proposed approach for dealing with anti-competitive behavior, our future earnings may be affected by the open-ended refund obligation.

Additionally, federal legislative initiatives have been introduced and discussed to address the problems being experienced in some of these markets, including legislation seeking to impose price caps on sales. We cannot predict whether other proposals to re-regulate will be made or whether legislative or other attention to the restructuring of the electric power industry will cause the restructuring to be delayed or reversed. 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.

If Regional Transmission Organizations (RTOs) are established as envisioned by Order No. 2000, "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 arenas to the development of RTOs.

The FERC also has initiated a rulemaking proceeding to 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, and specifications regarding the entities that administer these markets and for market monitoring and mitigation, that could be used in all RTOs. We cannot predict at this time what effect FERC's standard market design will have on our business growth prospects and financial results.

Partly in response to the bankruptcy of Enron, there have been proposals in the United States Congress to make online platforms that trade energy and metals derivatives subject to oversight by the Commodities Futures Trading Commission (CFTC), to prohibit market price manipulation and fraud. Under some of these proposals, dealers in energy derivatives would be required to file reports with the CFTC and maintain amounts of capital, as determined by the CFTC, to support the risks of their transactions. Other proposals would require the CFTC to review these markets for potential regulatory recommendations. We do not know what impact, if any, these proposals would have on our business if enacted. Additionally, there may be other broader proposals introduced to submit energy trading to comprehensive regulation by the FERC or by the CFTC.

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 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 public utility commissions regarding siting, environmental and other health and safety matters. The FERC has authorized us to sell our generation 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.

Uncertainty Related to the New York Regulatory Environment. The New York market is subject to significant regulatory oversight and control. Our operating results are as dependent on the continuance of the regulatory structure as they are on fluctuations in the market price for electricity. 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 revenues and costs. The primary regulatory risk in this market is associated with the oversight activity of the New York Public Service Commission, the New York Independent System Operator (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 energy and ancillary services. The NYISO also has the ability, in some cases subject to FERC approval, to impose cost-based pricing and/or price caps. The NYISO has implemented a measure known as the "Automated Mitigation Procedure" (AMP) under which day-ahead energy bids will be automatically reviewed and, if necessary, mitigated if economic or physical withholding is determined. Proposed modifications to the AMP provide a level of uncertainty over the impacts of that procedure in the summer of 2002. FERC has also directed the NYISO to adopt mitigation measures for all limits in New York City consistent with its overall market-monitoring plan. NYISO has filed in-city mitigation measures with the FERC, which it is proposing to be implemented beginning in late spring of 2002. The full impact of these revisions may not be known until the summer of 2002.

Integration and Other Risks Associated with Our Orion Power Assets. We have made a substantial investment in our recent acquisition of Orion Power. If we are unable to profitably integrate, operate, maintain and manage our newly acquired power generation facilities, our results of operations will be adversely affected.

Duquesne Light Company is obligated to supply electricity at predetermined tariff rates to all retail customers in its existing service territory who do not select another electricity supplier. Orion Power has committed to provide 100% of the energy that Duquesne Light Company needs to meet this obligation under a contract that was recently extended through December 2004. If our obligation under this contract exceeds the available output from the combination of Orion Power's generation facilities and our additional generation facilities in the region, we would be forced to buy additional energy at prevailing market prices and, in certain cases where we failed to deliver the required amount, we could incur penalties during periods of peak demand of up to $1,000 per megawatt hour. If this situation were to occur during periods of peak energy prices, we could suffer substantial losses that could materially adversely affect our results of operations. In addition, our revenues generated under this contract may be adversely impacted if a substantial number of Duquesne Light Company's retail customers select other retail electric providers.

Operating Risks. Our Wholesale Energy operations and our European Energy operations 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. A significant portion 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 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 operating costs. Any unexpected failure to produce power, including failure caused by breakdown or forced outage, could result in reduced earnings.

We depend on transmission and distribution facilities owned and operated by utilities and other power companies to deliver the electricity we sell from our power generation facilities to our customers, who in turn deliver these products to the ultimate consumers of the power. If transmission is disrupted, or transmission capacity is inadequate, our ability to sell and deliver our products may be hindered.

Factors Affecting Our Acquisition and Project Development Activities. Our plans indicate a shift in emphasis from identifying and pursuing acquisition and development candidates to construction and integration of generation facilities. We believe this is a temporary shift based on the requirements of integrating the Orion Power assets and the maturation of both our and Orion Power's development projects and by the current state of the wholesale electricity and capital markets.

There are numerous risks relating to the acquisition and development of power generation plants and construction and integration of these facilities. We may not be able to identify attractive acquisitions or development opportunities, complete acquisitions or development projects we undertake, or we may not be able to integrate these plants, especially larger acquisitions, into our portfolios and achieve the synergies, including cost savings, we originally envisioned.

Currently, we have a select number of power generation facilities under development and many under construction (either owned or leased). Our completion of these facilities is subject to the following:

- market prices,
- shortages and inconsistent quality of equipment, material and labor,
- financial market conditions and the results of our financing efforts,
- actions by rating agencies with respect to us or our competitors,
- 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, construction or development. 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 initial environmental, siting and other governmental permits and approvals is complicated, expensive, lengthy and subject to significant uncertainties. Transmission interconnection, fuel supply and cooling water 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. We may not be successful in the development or construction of power generation facilities in the future.

As a result of several recent events, including the United States economic recession, the price decline of our industry sector in the equity capital markets and the downgrading of the credit ratings of several of our significant competitors, the availability and cost of capital for our business and the businesses of our competitors has been adversely affected. In response to these events and the intensified scrutiny of companies in our industry sector by the rating agencies, we have reduced our planned capital expenditures by $2.7 billion over the 2002 - 2006 time frame.

Successful integration of plants, especially acquisitions, is subject to a number of risks, including the following:

- unforeseen liabilities or other exposures,
- inaccurate due diligence of acquired facilities, such as underestimates of outage rates and operating costs,
- inability to achieve adequate cost savings in both overhead and operations,
- inability to achieve various commercial synergies with existing operations, and
- market prices for power and fuels.

Any of these factors could significantly affect the economic impact of an acquisition on our results of operations.

As part of this integration process and our temporary shift in emphasis, the Orion Power plants will be part of an operations improvement process that strives to achieve both reduced operating and maintenance costs and increase gross margins through improved availability and reliability of plants. This process is currently underway at our other plants and will be introduced at the Orion Power facilities beginning in the third quarter of 2002.

Increasing Competition in Our Industry. Our Wholesale Energy business 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. As pricing information becomes increasingly available in the energy trading and marketing business, we anticipate that our operations will experience greater competition and downward pressure on per-unit profit margins. Furthermore, demands for liquidity to support trading and merchant asset businesses are increasing at the same time that the credit rating agencies are reviewing the liquidity and other credit criteria for trading, marketing and merchant generation firms. Other companies we compete with may not have similar credit ratings pressure or may have higher credit ratings. The growth of electronic trading platforms has increased the number of transactions, potential counterparties and level of price transparency in the energy commodity market. As a result, we are likely to transact with a wide range of customers potentially increasing our risk due to their changing credit circumstances, while at the same time potentially diversifying our reliance on a smaller number of customers.

Developments with respect to our competitors frequently have a collateral and tangible impact on us. Credit and liquidity concerns impact our ability to do business with counterparties. Adverse regulatory and political ramifications can result from activities and investigations directed at our competitors.

Hydroelectric Facilities Licensing. 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.

FACTORS AFFECTING THE RESULTS OF OUR EUROPEAN ENERGY OPERATIONS

General. Our European Energy segment intends to focus its activities in existing trading markets in the Netherlands, the United Kingdom, Germany, the Scandinavian countries, Austria and Switzerland. Historical results of operations may not be indicative of future results of operations. In particular, results of operations for our European Energy segment prior to 2001 reflect the impact of a regulated generation price system that has been discontinued. In addition, in 2001 and prior years, under Dutch corporate income tax laws, the earnings of REPGB were subject to a zero percent Dutch corporate income tax rate as a result of the Dutch tax holiday applicable to its electric industry. In 2002, all of European Energy's earnings in the Netherlands will be subject to the standard Dutch corporate income tax rate, which currently is 34.5%. Furthermore, European Energy's results of operations for 2001 include the effect of a number of non-recurring items, including the $37 million net gain resulting from the settlement of a stranded cost indemnity agreement.

Future results of operations of our European Energy segment could be affected by, among other things, the following:

- increasing competition in the Dutch wholesale energy market, resulting in declining electric power margins,

- the timing and pace of the deregulation of other sectors of the European energy markets,

- the continuing negative impact of the bankruptcy of Enron on market liquidity and credit requirements in European trading markets,

- the mark-to-market price risk exposure associated with certain stranded cost electricity and natural gas supply contracts,
- the impact of any renegotiation of European Energy's stranded cost contracts,
- the impact and changes of natural gas tariffs pursuant to changes in the regulatory structure,
- the ability to negotiate new contracts or renew contracts with customers on favorable terms, and
- the impact of slowing economic growth on power generation demand in the markets in which our European Energy segment operates.

Competition in the European Market. Competition for energy customers in the markets in which our European Energy segment operates is 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, co-generators, various producers of alternate sources of power and non-Dutch generators of electric power, primarily from France and Germany. As of December 31, 2001, 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.

Our European Energy segment's trading and marketing operations are also subject to increasing levels of competition. 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.

Deregulation of the Dutch Market. The Dutch wholesale electric market was completely opened to competition on January 1, 2001. Consistent with our expectations at the time we acquired our operations in the Netherlands, the gross margin of our European Energy segment declined in 2001 as a result of the deregulation of the market and the termination of an agreement with the other Dutch generators and the Dutch distributors. Commercial markets 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, 2003. 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.

Plant Outages. During 2001, our margins were negatively impacted by unplanned outages at some of our Dutch generation facilities. The unplanned outages were primarily due to malfunctions of the generation turbines and related equipment and complications encountered in the maintenance of one of our facilities. We estimate that these unplanned outages resulted in losses of approximately $11 million, a significant portion of which is covered by property damage and business interruption insurance. For additional information regarding operational risks applicable to our European Energy segment, including unplanned plant outages, please read " - Factors Affecting the Results of Our Wholesale Energy Operations - Operating Risks."

Other Factors. In December 2001, REPGB and its former shareholders entered into a settlement agreement resolving the former shareholders' stranded cost indemnity obligations under the purchase agreement of REPGB. For additional information regarding the stranded cost indemnity settlement and the potential impact on earnings from changes in the valuation in the future of the related stranded cost contracts, please read Notes 6(b) and 13(f) to our consolidated financial statements. We have begun discussions with the other parties to these contracts to modify the terms of certain of the out-of-market contracts. The structure of these settlements, if consummated, likely would entail an upfront cash payment to the counterparty in exchange for amendments to price and other terms intended to make the contracts more market conforming. REPGB would seek to fund these payments, if made, to the extent possible through the proceeds from the settlement of its stranded cost indemnity agreement and, possibly, anticipated distributions from NEA. We cannot currently predict the outcome of these negotiations. However, to the extent that these discussions result in amendments to the contracts, we could realize a gain.

We are in the process of reviewing our European Energy segment's goodwill and certain intangibles for impairment pursuant to SFAS No. 142. For information regarding assessing the impairment in 2002 under SFAS No. 142, please read " - New Accounting Pronouncements and Critical Accounting Policies."

Our European operations are subject to various risks incidental to investing or operating in foreign countries. These risks include economic risks, such as fluctuations in currency exchange rates, restrictions on the repatriation of foreign earnings and/or restrictions on the conversion of local currency earnings into U.S. dollars. For example, we estimate that the impact of the devaluation of the Euro relative to the U.S. dollar during 2001 negatively affected U.S. dollar net income by approximately $2 million.

FACTORS AFFECTING THE RESULTS OF OUR RETAIL ENERGY OPERATIONS

General. The Texas retail electricity market fully opened to competition in January 2002. Therefore, we do not expect the earnings from our Retail Energy segment for past years to be indicative of our future earnings and results. The level of future earnings generated by our Retail Energy segment will depend on numerous factors including:

- legislative and regulatory developments related to the newly-opened retail electricity market in Texas and changes in the application of such laws and regulations,

- the effects of competition, including the extent and timing of the entry or exit of competitors in our markets and the impact of competition on retail prices and margins,

- customer attrition rates and cost associated with acquiring and retaining new customers,

- our ability to negotiate new contracts or renew contracts with customers on favorable terms,
- the timing and extent of changes in wholesale commodity prices and transmission and distribution rates,
- our ability to procure adequate electricity supply upon economic terms,
- our ability to effectively hedge commodity prices,
- our ability to pass increased supply costs on to customers in a timely manner,
- our ability to timely perform our obligations under our customer contracts,

- market liquidity for wholesale power,
- the financial condition and payment patterns of our customers,
- weather variations and other natural phenomena,
- the timely and accurate implementation of the new internal and external information technology systems and processes necessary to provide customer information and to implement customer switching in the retail electricity market in Texas which was established in late 2001,
- the costs associated with operating our internal customer service and other operating functions, and
- the timing and accuracy of ERCOT settlements, and the exchange of information between ERCOT, the transmission and distribution utility and our retail electric provider, which facilitates our Retail Energy segment's billing, collection and supply management processes.

Competition in the Texas Market. 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 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 Reliant Energy's electric utility who did not take action to select another retail electric provider. Under the market framework established by the Texas electric restructuring law, we are recognized as the affiliated retail electric provider of Reliant Energy's electric utility. The Distribution will not change this treatment, even though we will cease to be a subsidiary of Reliant Energy after the Distribution. 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, which is referred to in the law as the "price to beat," whereas other retail electric providers are allowed to sell electricity to these customers at any price. Our price to beat was set at a level resulting in an estimated average 17% reduction from December 31, 2001 rates for our residential customers and an estimated average 22% reduction from December 31, 2001 rates for our pre-existing small commercial customers. The wholesale energy supply cost component, or "fuel factor," included in our price to beat was initially set by the Texas Utility Commission at the then average forward 12 month gas price strip of approximately $3.11/mmbtu.

We are not permitted to offer electricity to these customers at a price other than the price to beat until January 1, 2005, unless before that date the Texas Utility Commission 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 will not be 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 retail electric providers. Customers were given the opportunity to switch beginning in August 2001 through the retail pilot project. Due to system related problems which restricted the timely switching of customers during the pilot project and in early 2002, we cannot be sure of the number of customers that have attempted to switch to other retail electric providers. For additional information regarding retail market systems problems, please read " - Operational Risks." Between the beginning of the pilot project in August 2001 and February 28, 2002, we estimate that approximately 67,000 customers (or approximately 4% of our residential and small commercial customers) have switched to other retail electric providers. Due to the switching systems problems, the actual numbers of customers that switched or attempted to switch by this date may actually be higher.

As discussed above, as the affiliated retail electric provider, we may only sell electricity to residential and small commercial customers in Reliant Energy's electric utility service territory at the price to beat for a period of up to three years. In addition, as the affiliated retail electric provider, we are obligated to offer the price to beat to requesting residential and small commercial customers in Reliant Energy's electric utility service territory through January 1, 2007.

We are providing commodity service to the large commercial, industrial and institutional customers previously served by Reliant Energy's electric utility who did not take action to select another retail electric provider. In addition, we have signed contracts to provide electricity and services to large commercial, industrial and institutional customers, both in the Houston area as well as outside of the Houston market. We or any other retail electric

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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 select us as their provider may subsequently decide to switch to another provider at the conclusion of the term of their contract with us.

In most retail electric markets outside the Houston area, our principal competitor may be the local incumbent 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 utilities' affiliates, we may face competition from a number of other retail providers, including affiliates of other non-incumbent utilities, independent retail electric providers and, with respect to sales to large economical and industrial customers, independent power producers acting as retail electric providers. Some of these competitors or potential competitors may be larger and better capitalized than we are.

Generally, retail electric providers will purchase electricity from the wholesale generators at unregulated rates, sell electricity to their retail customers and pay the transmission and distribution utility a regulated tariffed rate for delivering the electricity to their customers. Retail electric providers will then bill and collect payments from the customers. Because we are required to sell electricity to residential and small commercial customers in the Houston area at the price to beat, we may lose a significant number of these customers to non-affiliated retail electric providers if their cost to provide electricity to these customers is lower than the price to beat. In addition, the results of our Retail Energy operations for sales to residential and small commercial customers over the next several years in Texas will be largely dependent upon the amount of gross margin, or "headroom," available in our price to beat. Until 2004, when we will have the option to acquire Reliant Energy's ownership interest in Texas Genco, our results will be largely based on the ability of our Wholesale Energy segment to buy power at prices that yield acceptable gross margins at revenue levels determined by the price to beat set by the Texas Utility Commission. The available headroom in the price to beat is equal to the difference between the price to beat and the sum of the charges, fees and transmission and distribution utility rates approved by the Texas Utility Commission and the price we pay for power to serve our price to beat customers. The larger the amount of headroom, the more incentive new market entrants should have to provide retail electric services in that particular market. The Texas Utility Commission's regulations allow affiliated retail electric providers to adjust their price to beat fuel factor based on the percentage change in the price of natural gas. In addition, they may also request an adjustment as a result of changes in their price of purchased energy. In such a request, they 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 Texas Utility Commission. Affiliated retail electric providers may not request that their price to beat be adjusted more than twice a year. We cannot estimate with any certainty the magnitude and frequency of the adjustments we may seek, if any, and the eventual impact of such adjustments on the amount of headroom. Based on forward gas prices at the end of March 2002, we would be able to increase our price to beat rates by approximately 4-5%. Available headroom in the Houston market, as well as in other Texas markets where we intend to compete, will be affected by any changes in transmission and distribution rates that may be requested by the transmission and distribution provider in the respective service territory and in taxes, fees and other charges assessed or levied by third parties. Any changes in transmission and distribution rates must be approved by the Texas Utility Commission. The Texas Utility Commission has initiated a proceeding to determine what taxes a municipality or other local taxing authority can charge retail electric providers relating to the provision of electricity.

In Texas, our Wholesale Energy group and our Retail Energy group work together in order to determine the price, demand and supply of energy required to meet the needs of our Retail Energy segment's customers. We may purchase capacity from non-affiliated parties in the capacity auctions mandated by the Texas Utility Commission and from Texas Genco in auctions substantially similar to, but separate from, the mandated auctions. These positions are continuously monitored and updated based on retail sales forecasts and market conditions. However, we do not expect to cover the entire exposure of these positions to market price volatility, and the coverage will vary over time. For a discussion of risks similar to those associated with our Retail Energy segment's hedging activities, please read " - Factors Affecting the Results of Our Wholesale Energy Operations - Price Volatility," and " - Risks Associated with Our Hedging and Risk Management Activities." In addition to the factors noted in these sections, our ability to adequately hedge our retail electricity requirements is also dependent on the accurate forecast of the number of our customers in each customer class and uncertainties associated with the recently established ERCOT settlement procedures.

Obligations as a Provider of Last Resort. The Texas electric restructuring law requires the Texas Utility Commission to designate certain retail electric providers as providers of last resort in areas of the state in which retail competition is in effect. A provider of last resort is required to offer a standard retail electric service package for each class of customers designated by the Texas Utility Commission at a fixed, nondiscountable rate approved by the Texas Utility Commission, and is required to provide the service package to any requesting retail customer in the territory for which it is the provider of last resort. In the event that another retail electric provider fails to serve any or all of its customers, the provider of last resort is required to offer that customer the standard retail service package for that customer class with no interruption of service to the customer. The Texas Utility Commission designated our subsidiary, StarEn Power, to serve as the provider of last resort for residential and small commercial customers in the western portion of the Dallas/Fort Worth metropolitan area formally served by Texas Utilities, Inc., a subsidiary of TXU, Inc. In addition, StarEn Power has been appointed as the provider of last resort for large commercial, industrial and institutional customers in Reliant Energy's electric utility service territory. StarEn Power will serve two consecutive six month terms as the provider of last resort. The first term began on January 1, 2002. The second six-month term, beginning July 1, 2002, will include a potential adjustment to the energy component of our provider of last resort rate based on a NYMEX Henry Hub natural gas index. The terms and rates for provider of last resort service are governed by a settlement between us and various interested parties, which settlement was approved by the Texas Utility Commission. In this role, StarEn Power retains the rights to require customer deposits and disconnect service in accordance with Texas Utility Commission rules, and to petition the Texas Utility Commission for a price change in the event it is determined that StarEn power will experience a net financial loss over the term of its provider of last resort obligations. In the first quarter of 2002, the Texas Utility Commission initiated a proceeding to review and possibly amend both the governing rules and structure of provider of last resort service and obligations. This proceeding is in its initial stages and we cannot be sure whether the structure of provider of last resort service and obligations will change, how they will change or what effect, if any, any changes would have on the financial condition, results of operations or cash flows of StarEn Power or our Retail Energy segment.

"Clawback" Payment to Reliant Energy. To the extent the price to beat exceeds the market price of electricity, we will be required to make a payment to Reliant Energy in 2004 unless the Texas Utility Commission determines that, 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 (at or below one MW), as applicable, within Reliant Energy's electric utility service territory is committed to be served by retail electric providers other than us. If the 40% test is not met and the reconciliation and a retail payment is required, the amount of this retail payment will be equal to (a) the amount that the price to beat, less non-bypassable delivery charges, is in excess of the market price of electricity per customer, but not to exceed $150 per customer, multiplied by (b) the number of residential or small commercial customers, as the case may be, that we serve on January 1, 2004 in Reliant Energy's electric utility service territory, less the number of new retail electric customers we serve in other areas of Texas.

Operational Risks. The price of purchased power could have an adverse effect on the costs incurred by our Retail Energy segment in acquiring power to serve the demand of its retail customers. For additional information regarding commodity price volatility, please read " - Factors Affecting the Results of Our Wholesale Energy Operations - Price Volatility."

We are dependent on local 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. Additionally, we are dependent on the local transmission and distribution utilities for the reading of our customers' energy meters. We are required to rely on the local utility or, in some cases, the independent transmission system operator, 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 local utilities or system operators could have a material negative impact on our business and results of operations and cash flows.

The ERCOT ISO is the independent system operator responsible for maintaining reliable operations of the bulk electric power supply system in the ERCOT market. 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. Problems in the flow of information between the ERCOT ISO, the transmission and distribution utility and the retail

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electric providers have resulted in delays in switching customers. While the flow of information is improving, operational problems in the new system and processes are still being worked out. In some instances, large commercial, industrial and institutional customers who have not yet been switched to be customers of Solutions due to system delays are paying for electricity at the default rate which is higher than their contracted price of electricity. Until the customer is switched to us, Solutions cannot provide it electricity. This delay in switching has also caused us, at times, to sell in the spot market or through bilateral contracts at prices below the contracted prices the electricity that we had intended to provide to such customers.

The ERCOT ISO is also responsible for handling scheduling and settlement for all electricity supply volumes in the Texas deregulated electricity market. In addition, 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. As part of settlement, the ERCOT ISO communicates the actual volumes delivered compared to the forecast volumes scheduled. The ERCOT ISO calculates an additional charge or credit based on the difference between the actual and forecast volumes, based on a market clearing price for the difference. Settlement charges also include allocated costs such as unaccounted-for energy. Currently, there is a three to four month delay in receiving final settlement information. As a result, we must estimate our supply costs. Timing delays in receiving final settlement information creates supply cost estimation risk.

FACTORS RELATED TO OUR SEPARATION FROM RELIANT ENERGY

Distribution. Although Reliant Energy has advised us that it currently intends to complete the distribution of our common stock to its shareholders promptly upon the receipt of certain regulatory approvals related to its restructuring, which it currently expects to obtain in the next few months, we cannot assure you whether or when the Distribution will occur. Reliant Energy is not obligated to complete the Distribution, and it may decide not to do so.

Upon completion of the Distribution, substantially all of the 240,000,000 shares of our common stock that Reliant Energy owns would be eligible for immediate resale in the public market. We are unable to predict whether significant amounts of our common stock will be sold in the open market in anticipation of, or following, the Distribution. We are also unable to predict whether a sufficient number of buyers would be in the market at that time, such that an imbalance of sellers and buyers could eventually affect the price of our stock.

A portion of Reliant Energy's common stock is held by index funds tied to the Standard & Poor's 500 Index, the Standard & Poor's Electric Utilities Index and the Dow Jones Utilities Index or other stock indices. If our stock is not included in these indices at the time of the Distribution, these index funds will be required to sell our stock. Similarly, other institutional stockholders are not allowed by their charters to hold the stock of companies that do not pay dividends. Since we currently do not intend to pay dividends, we expect that these stockholders will sell the shares of our common stock distributed to them. Any sales of substantial amounts of our common stock in the public market, or the expectation that such sales might occur, whether as a result of the Distribution or otherwise, could adversely affect the market price of our common stock.

Reliant Energy as a 80+% Stockholder. Reliant Energy owns over 80% of our outstanding common stock. As long as Reliant Energy owns a majority of our outstanding common stock, Reliant Energy will continue to be able to elect our entire board of directors without calling a special meeting. As a result, Reliant Energy, subject to any fiduciary duty owed to our minority stockholders under Delaware law, will be able to control all matters affecting us.

In addition, Reliant Energy 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, Reliant Energy would likely cause its representatives on our board of directors to direct our business so as not to breach any of these agreements. Moreover, the Texas Utility Commission and the state regulatory commissions of Arkansas and Minnesota have imposed limitations on the amount Reliant Energy or its subsidiaries may invest in foreign utility companies and, in some cases, foreign electric wholesale generating companies. These limitations are based upon Reliant Energy's consolidated net worth, retained earnings, and debt and stockholders' equity.

Possible Conflicts of Interest. We may have potential business conflicts of interest with Reliant Energy with respect to our past and ongoing relationships, and because of Reliant Energy's controlling ownership prior to the Distribution, we may not be able to resolve these conflicts on terms commensurate with those possible in arms' length transactions. In anticipation of our separation from Reliant Energy, we have entered into many agreements with Reliant Energy. These agreements may be amended upon agreement of the parties. While we are controlled by Reliant Energy, Reliant Energy may be able to require us to agree to amendments to these agreements. We may not be able to resolve any potential conflicts with Reliant Energy, and even if we do, the resolution may be less favorable than if we were dealing with an unaffiliated party.

Our executive officers and some of our directors own a substantial amount of Reliant Energy common stock and options to purchase Reliant Energy common stock. Ownership of Reliant Energy common stock by our directors and officers after the Distribution could create, or appear to create, potential conflicts of interest when directors and officers are faced with decisions that could have different implications for Reliant Energy than they do for us.

We expect that even after the Distribution, two of our directors will also be directors of Reliant Energy. One of these directors will be our chairman, president and chief executive officer. These directors will owe fiduciary duties to the stockholders of each company. As a result, in connection with any transaction or other relationship involving both companies, these directors may need to recuse themselves and to not participate in any board action relating to these transactions or relationships.

Adverse Tax Consequences. If we take actions which cause the Distribution to fail to qualify as a tax-free transaction, we will be required to indemnify Reliant Energy for any resulting taxes. Under an agreement with Reliant Energy, if we breach any representation in the agreement relating to the IRS ruling that Reliant Energy receives in connection with the Distribution, take any action that causes our representations in the agreement relating to the ruling to be untrue or engage in a transaction after the Distribution that causes the Distribution to be taxable to Reliant Energy, we will be required to indemnify Reliant Energy for any resulting taxes. The amount of any indemnification payments could be substantial.

Current tax law provides that, depending on the facts and circumstances, the Distribution may be taxable to Reliant Energy if we undergo a 50% or greater change in stock ownership within two years after the Distribution. Under agreements with Reliant Energy, Reliant Energy is entitled to require us to reimburse any tax costs incurred by Reliant Energy as a result of a transaction resulting in a change in control of our company. These costs may be so great that they delay or prevent a strategic acquisition or change in control of our company.

Deconsolidation from the Reliant Energy Consolidated Tax Group. Subsequent to the Distribution, we will cease to be a member of the Reliant Energy consolidated tax group. This separation will have both current and future income tax implications to us. The event of deconsolidation itself will result in the triggering of deferred intercompany gains. We will recognize taxable income related to these gains, which will not have a material impact on our net income and cash flow. In addition to the current income tax consequences triggered by the act of deconsolidation discussed above, our separation from the Reliant Energy consolidated tax group will change our overall future income tax posture. As a result, we could be limited in our ability to effectively use future tax attributes. We have agreed with Reliant Energy 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 Reliant Energy consolidated group subject to Reliant Energy's consent. Reliant Energy has agreed not to unreasonably withhold such consent. Additionally, we may also be able to utilize such net operating losses in our tax years after deconsolidation (subject to the applicable carryforward limitation periods) but only to the extent of our income in such tax years.

OTHER FACTORS

Terrorist Attacks and 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 retaliatory military response 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 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.

Environmental Regulation. Our wholesale 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 occur, our business, operations and financial condition 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, the operation of our facilities could be prevented or become subject to additional costs.

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

Holding Company Organizational Structure. 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. As of December 31, 2001, all of the specified conditions in these agreements were satisfied. Under the credit agreements of certain of Orion Power's subsidiaries, these subsidiaries are restricted from distributing cash to Orion Power.

In addition, the ability of REMA, our subsidiary that owns some of the power generation facilities in our Northeast regional portfolio, to pay dividends or make restricted payments to us is restricted under the terms of three lease agreements under which we lease all or an undivided interest in these generating facilities. These agreements allow our Mid-Atlantic subsidiary to pay dividends or make restricted payments only if specified conditions are satisfied, including maintaining specified fixed charge coverage ratios.

Liquidity Concerns. As of February 19, 2002, we have $2.9 billion of credit facilities which will expire in 2002. To the extent that we continue to need access to this amount of committed credit, we expect to extend or replace these facilities. The current credit environment currently impacting our industry may require our future facilities to include terms that are more restrictive or burdensome or at higher borrowing rates than those of our current facilities. In addition, the terms of any new credit facilities may be adversely affected by any delay in the date of the Distribution. For a discussion of other factors affecting our sources of cash and liquidity, please read "Liquidity and Capital Resources."

LIQUIDITY AND CAPITAL RESOURCES

HISTORICAL CASH FLOWS

The net cash provided by or used in operating, investing and financing activities for 1999, 2000 and 2001 is as follows (in millions).

	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
Cash provided by (used in):			
Operating activities	$ 35	$ 328	$ (127)
Investing activities	(1,406)	(3,013)	(838)
Financing activities	1,408	2,721	1,000

Cash Provided by Operating Activities

Net cash provided by operating activities during 2001 decreased by $455 million compared to 2000. This decrease was primarily due to changes in working capital and other changes in assets and liabilities. Changes in working capital and other assets and liabilities in 2001 resulted in net cash outflows of approximately $720 million primarily due to the following:

- a $409 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 Wholesale Energy in 2001 which was accrued in 2000;

- a lease prepayment of $181 million related to the REMA sale-leaseback agreements (please see Note 13(c) to our consolidated financial statements);

- increased restricted cash of $117 million related to our REMA operations (please see Note 2(j) to our consolidated financial statements); and

- increased deposits of $145 million in a collateral account related to an equipment financing structure (please see Note 13(h) to our consolidated financial statements);

- 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.

Changes in working capital and other assets and liabilities in 2000 resulted in net cash outflows of approximately $27 million primarily due to the following:

- increased restricted cash of $50 million related to our REMA operations;

- increased deposits of $85 million in a collateral account related to an equipment financing structure;

- increased net margin deposits of $206 million on energy trading and hedging activities as a result of increased commodity volatility and relative price levels of natural gas and power in the fourth quarter of 2000; and

- other changes in working capital;

- the foregoing items were partially offset by a $142 million net cash inflow due to an increase in accounts payable partially offset by an increase in accounts receivable and net intercompany accounts receivable due to the timing of cash receipts and cash payments related to a significant gas payable which was accrued in 2000 and $123 million of proceeds from the sale of an investment in marketable debt securities during 2000.

Cash flows from operations, excluding changes in working capital and other changes in assets and liabilities, were approximately $593 million in 2001 compared to approximately $355 million in 2000. This increase was primarily due to a $498 million increase in operating margins from Wholesale Energy's power generation operations in 2001 compared to 2000. This increase was partially offset by increased costs related to Retail Energy'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 gross margins as the Dutch electric market was completely opened to wholesale competition on January 1, 2001.

Net cash provided by operating activities during 2000 increased by $293 million compared to 1999. This increase primarily resulted from proceeds from the sale of an investment in marketable debt securities, improved operating results of Wholesale Energy's California generating facilities, incremental cash flows provided by

REPGB, acquired in the fourth quarter of 1999, and cash flows from the Mid-Atlantic generating facilities, acquired in the second quarter of 2000.

Cash Used in Investing Activities

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.

Net cash used in investing activities increased by $1.6 billion during 2000 compared to 1999. This increase was primarily due to the funding of the remaining purchase obligation for REPGB for $982 million on March 1, 2000 and the purchase of REMA for $2.1 billion on May 12, 2000, as well as increased capital expenditures related to the construction of domestic power generation projects. Proceeds of $1.0 billion from the REMA sale-leaseback partially offset these increases, as well as 1999 payments related to the acquisition of REPGB and a generating facility located in Florida.

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 Reliant Energy, of which $1.0 billion was converted to equity. In August 2000, we entered into separate sale-leaseback transactions with each of the three owner-lessors for our respective 16.45%, 16.67% and 100% interests in the Conemaugh, Keystone and Shawville generating stations, respectively, 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 Reliant Energy. For additional information about the acquisition and these transactions, please read Notes 5(a) and 13(c) to our consolidated financial statements.

Acquisition of REPGB. In the fourth quarter of 1999, we funded $833 million of the REPGB purchase obligation. 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 that matures in March 2003. For more information about the acquisition, please read Note 5(b) to our consolidated financial statements.

Cash Used in/Provided by Financing Activities

Cash flows provided by financing activities decreased by $1.7 billion in 2001 compared to 2000, primarily due to a decrease in borrowings from Reliant Energy coupled with advancing excess cash on a short-term basis to a subsidiary of Reliant Energy which provides a cash management function for Reliant Energy, reduced contributions from Reliant Energy, 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 Wholesale Energy's capital expenditures and for general corporate purposes, and by $1.7 billion in net proceeds from the IPO.

Cash flows provided by financing activities increased by $1.3 billion in 2000 compared to 1999. The increase resulted primarily from an increase in contributions from Reliant Energy and net proceeds from long-term debt from third parties. We utilized the net borrowings incurred during 2000 to fund the remaining REPGB purchase obligation, to fund the acquisition of REMA, to support increased capital expenditures by Wholesale Energy and for general corporate purposes.

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 Reliant Energy, we used $147 million of the net proceeds to repay certain indebtedness owed to Reliant Energy. We used the remainder of the net proceeds of the IPO for repayment of third party borrowings, capital expenditures, repurchase of common stock and to increase our working capital. Proceeds not initially utilized from the IPO during 2001 were advanced on a short-term basis to a subsidiary of Reliant Energy which provides a cash management function for Reliant Energy. As of December 31, 2001, we have $390 million of outstanding advances to this subsidiary of Reliant Energy. In May 2001, prior to the closing of the IPO, Reliant Energy converted to equity or contributed to us an aggregate of $1.7 billion of indebtedness owed by us to Reliant Energy and it subsidiaries of which $35 million was related to accrued intercompany interest expense. Following the IPO, Reliant Energy no longer provided us financing or credit support, except for specified transactions or for a limited period of time. For additional information, please read Note 4 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 an aggregate purchase price of $189 million.

CONSOLIDATED CAPITAL REQUIREMENTS AND USES OF CASH

Our liquidity and capital requirements are affected primarily by the results of operations, capital expenditures, debt service requirements and working capital needs. We expect to grow through the construction of new generation facilities and the acquisition of generation facilities, the expansion of our energy trading and marketing activities and the expansion of our energy retail business. We expect any resulting capital requirements to be met with cash flows from operations, and proceeds from debt and equity offerings, project financings, securitization of assets, other borrowings and off-balance sheet financings. Additional capital expenditures, some of which may be substantial, depend to a large extent upon the nature and extent of future project commitments which are discretionary. In the discussion below, we have provided several tables outlining our expected future capital requirements by category of expenditure followed by more detailed descriptions of the most significant of our currently known future capital requirements and descriptions of known uncertainties that could impact these items.

The following table sets forth our consolidated capital requirements for 2001, and estimates of our consolidated capital requirements for 2002 through 2006 (in millions).

	2001	2002	2003	2004
Wholesale Energy(1)(2)(3)	$ 658	$ 3,579	$ 322	$ 1
European Energy	21	22	--	
Retail Energy	117	40	19	
Other Operations	44	75	46	
Major maintenance cash outlays	88	94	87	1
Total	$ 928	$ 3,810	$ 474	$ 3

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(1) Capital requirements for 2002 includes $2.9 billion for the acquisition of Orion Power.

(2) In connection with our separation from Reliant Energy, Reliant Energy has granted us an option, subject to completion of the Distribution, to purchase all of the shares of capital stock owned by Reliant Energy in January 2004 of an entity (Texas Genco) that will hold the Texas generating assets of Reliant Energy's electric utility division. This option may be exercised between January 10, 2004 and January 24, 2004. The purchase of Texas Genco has been excluded from the above table. For additional information regarding this option to purchase Texas Genco, please read Note 4(b) to our consolidated financial statements.

(3) We currently estimate the capital expenditures by off-balance sheet special purpose entities to be $704 million, $343 million, $163 million and $48 million in 2002, 2003, 2004 and 2005, respectively. Capital expenditures for these projects have been excluded from the table above. Please read " - Off-Balance Sheet Transactions - Construction Agency Agreements" and " - Equipment Financing Structure" for additional information regarding these transactions.

Acquisition of Orion Power. On February 19, 2002, we acquired all of the outstanding shares of common stock of Orion Power for $26.80 per share in cash for an aggregate purchase price of $2.9 billion. As of February 19, 2002, Orion Power's debt obligations were $2.4 billion ($2.1 billion net of cash acquired, some of which is restricted pursuant to debt covenants). We funded the purchase of Orion Power with a $2.9 billion credit facility (Orion Bridge Facility) and $41 million of cash on hand. Please read " - Consolidated Sources of Cash - Orion Bridge Facility" for further information.

Generating Projects. As of December 31, 2001, we had three generating facilities under construction. Total estimated costs of constructing these facilities are $1.1 billion, including $304 million in commitments for the purchase of combustion turbines. As of December 31, 2001, we had incurred $690 million of the total projected costs of these projects, which were funded primarily from equity and debt facilities. In addition, we have options to purchase additional combustion turbines for a total estimated cost of $42 million. We are actively attempting to market these turbines, having determined that they are in excess of our current needs. In addition to these facilities, we are constructing facilities as construction agents under construction agency agreements under synthetic leasing arrangements, which permit us to lease or buy each of these facilities at the conclusion of their construction. For more information regarding the construction agency agreements, please read " - Off-Balance Sheet Transactions - Construction Agency Agreements."

Environmental Expenditures. We anticipate investing up to $135 million in capital and other special project expenditures between 2002 and 2006 for environmental compliance, totaling approximately $53 million, $20 million, $9 million, $29 million and $24 million in 2002, 2003, 2004, 2005 and 2006, respectively, which is included in the above table. Additionally, environmental capital expenditures for the recently acquired Orion Power assets were estimated by Orion Power to be approximately $241 million over the same time period. We are currently reviewing Orion Power's estimates.

The following table sets forth estimates of our consolidated contractual obligations as of December 31, 2001 to make future payments for 2002 through 2006 and thereafter (in millions):

CONTRACTUAL OBLIGATIONS	TOTAL	2002	2003	2004	2
Long-term debt	$ 892	$ 24	$ 539	$ 42	$
Short-term borrowing, including credit facilities	297	297	--	--	
Mid-Atlantic generating assets operating lease payments	1,560	136	77	84	
Other operating lease payments	859	52	72	87	
Trading and marketing liabilities	1,840	1,478	216	85	
Non-trading derivative liabilities	1,038	399	191	113	
Other commodity commitments	3,134	465	242	207	
Other long-term obligations	300	10	10	10	
Total contractual cash obligations	$ 9,920	$ 2,861	$ 1,347	$ 628	$

Long-term debt obligations as of December 31, 2001, include $829 million of borrowings under credit facilities that have been 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.

As of December 31, 2001, we have issued $396 million of letters of credit of which $345 million were issued under two credit facilities expiring in 2003 and $51 million were issued under a credit facility expiring in 2004.

Mid-Atlantic Assets Lease Obligation. In August 2000, we entered into separate sale-leaseback transactions with each of the three owner-lessors for our respective 16.45%, 16.67% and 100% interests in the Conemaugh, Keystone and Shawville generating stations, respectively, which we acquired as part of the REMA acquisition. As lessee, we lease an interest in each facility from each owner-lessor under a facility lease agreement. The equity interests in all the subsidiaries of REMA are pledged as collateral for REMA's lease obligations. In addition, the subsidiaries have guaranteed 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 credit rating on its long-term unsecured senior debt of at least BBB from Standard & Poor's and Baa2 from Moody's, guarantees the lease obligations. For additional discussion of these lease transactions, please read Notes 5(a) and 13(c) to our consolidated financial statements. We expect to make lease payments through 2029 under these leases, with total cash payments of $1.6 billion. The lease terms expire in 2034. During 2000 and 2001, we made cash lease payments totaling $1 million and $259 million, respectively.

Other Operating Lease Commitments. For a discussion of other operating leases, please read Note 13(c) to our consolidated financial statements.

Other Commodity Commitments. For a discussion of other commodity commitments, please read Note 13(a) to our consolidated financial statements.

Naming Rights to Houston Sports Complex. In October 2000, we acquired the naming rights for the new football stadium for the Houston Texans, the National

Football League's thirty-second franchise. The agreement extends for 31 years. The aggregate undiscounted cost of the naming rights under this agreement is expected to be $300 million. Starting in 2002, when the new stadium is operational, we will pay $10 million each year through 2032 for annual advertising under this agreement. For additional information on the naming rights agreement, please read Note 13(a) to our consolidated financial statements.

Payment to Reliant Energy. To the extent that our price for providing retail electric service to residential and small commercial customers in Reliant Energy's Houston service territory during 2002 and 2003, which price is mandated by the Texas electric restructuring law, exceeds the market price of electricity, we will be required to make a payment to Reliant Energy in early 2004. For discussion of possible payment, please read Note 13 (g) to our consolidated financial statements. Due to the nature of this possible payment, we currently cannot reasonably estimate this payment, accordingly it is excluded from the above table.

Treasury Stock Purchases. On December 6, 2001, our Board of Directors authorized us to purchase up to 10 million additional shares of common stock through June 2003. 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 such authorization through April 1, 2002, we have not purchased any of these shares of our common stock under this program.

In addition to the capital requirements discussed above, the following items, among others, could impact our future capital requirements.

Downgrade in our Credit Rating. In accordance with industry practice, we have entered into commercial contracts or issued guarantees related to our trading, marketing and risk management operations that require us to maintain an investment grade credit rating. If one or more of our credit ratings decline below investment grade, we may be obligated to provide additional or other credit support to the guaranteed parties in the form of a pledge of cash collateral, a letter of credit or other similar credit support.

Counterparty Credit Risk. We are exposed to the risk that counterparties who owe us money or physical commodities, such as energy or gas, as a result of market transactions fail to perform their obligations. Should the counterparties to these arrangements fail to perform, we might incur losses if we are forced to acquire alternative hedging arrangements or replace the underlying commitment at then-current market prices. In addition, we might incur additional losses to the extent of amounts, if any, already paid to the defaulting counterparties.

CONSOLIDATED SOURCES OF CASH

We believe that our current level of cash and borrowing capability, along with our future anticipated cash flows from operations and assuming successful refinancings of credit facilities as they mature, will be sufficient to meet the existing operational needs of our business for the next 12 months. If cash generated from operations is insufficient to satisfy our liquidity requirements, we may seek to sell either equity or debt securities or obtain additional credit facilities or long-term financings from financial institutions. In the discussion below, we have

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provided a description of the significant factors that could impact our cash flows from operations, our currently available liquidity sources, currently contemplated future liquidity sources and known uncertainties that could impact these sources.

The following items will affect our future cash flows from operations:

Reliant Resources Restricted Cash. Covenants under the Mid-Atlantic assets lease, discussed above, restrict REMA's ability to make dividend distributions. The restricted cash is available for REMA's working capital needs and for it to make future lease payments. As of December 31, 2001, REMA had $167 million of restricted cash. We currently anticipate that REMA will be able to satisfy the conditions necessary to distribute these restricted funds in 2002. In addition, the terms of two of our subsidiaries' indebtedness restrict their ability to pay dividends or make restricted payments to us in some circumstances. Specifically, our subsidiary which holds an electric power generation facility in Channelview, Texas (Channelview) and our subsidiary which holds an equity investment in the entity owning and operating an electric power generation facility in Nevada (El Dorado) are each party to credit agreements used to finance construction of their generating plants. Both the Channelview credit agreement and the El Dorado credit agreement allow the respective subsidiary 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. In both cases, the amount of the dividends or restricted payments that may be paid if the conditions are met is limited to a specified level and may be paid only from a particular account.

Orion Power Restricted Cash. Substantially all of Orion Power's operations are conducted by its subsidiaries. The terms of some of its subsidiaries' indebtedness restrict their ability to pay dividends to Orion Power or us. Restricted funds are available for such subsidiaries to make debt service payments and to meet their working capital needs. In addition, covenants under some indebtedness of Orion Power restrict its ability to pay dividends to us unless Orion Power meets certain conditions, including the ability to incur additional indebtedness without violating the required fixed charge coverage ratio of 2.0 to 1.0. A credit facility of Orion Power also restricts its ability to pay dividends to us unless the restrictions contained in certain of its subsidiaries' credit agreements have terminated and no restrictions remain under their credit agreements.

California Trade Receivables. As of December 31, 2001, we were owed $302 million by the Cal ISO, the California Power Exchange (Cal PX) and the California Department of Water Resources (CDWR) and California Energy Resource Scheduling for energy sales in the California wholesale market, during the fourth quarter of 2000 through December 31, 2001 and have recorded an allowance against such receivables of $68 million. From January 1, 2002 through March 26, 2002, we have collected $45 million of these receivable balances. For additional information regarding uncertainties in the California wholesale market, please read Notes 13(e) and 13(i) to our consolidated financial statements.

Other Items. For other items that may affect our future cash flows from operations, please read " - Certain Factors Affecting Future Earnings."

The following discussion summarizes our currently available liquidity sources and material factors that could impact that availability.

Credit Facilities. The following table provides a summary of the amounts owed and amounts available under our various credit facilities (in millions).

	TOTAL COMMITTED CREDIT	DRAWN AMOUNT	LETTERS OF CREDIT	U A

Reliant Resources, as of December 31, 2001 ...	$ 5,563	$ 1,078	$ 396	$
Orion Power, as of February 19, 2002	2,028	1,827	95	
Total				

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(1) Excludes $383 million of facilities expiring in November 2002 as borrowings under such facilities are convertible into a long-term loan.

As of February 19, 2002, we have $2.9 billion of credit facilities which will expire in 2002. To the extent that we continue to need access to this amount of committed credit, we expect to extend or replace these facilities. The current credit environment currently impacting our industry may require our future facilities to include terms that are more restrictive or burdensome or at higher borrowing rates than those of our current facilities.

Reliant Resources Credit Facilities Covenants. As of December 31, 2001, we, including certain of our subsidiaries, had committed credit facilities of $5.6 billion. Of these facilities, $5.0 billion contain various business and financial covenants requiring us to, among other things, maintain a ratio of net balance sheet debt to the sum of net balance sheet debt, subordinated affiliate balance sheet debt and stockholders' equity not to exceed 0.60 to 1.00. These covenants are not anticipated to materially restrict us from borrowing funds or obtaining letters of credit under these facilities. The remaining credit facilities of $0.6 billion, which were held by certain of our domestic power generation subsidiaries, contain various business and financial covenants that are typical for limited or non-recourse project financings. Such covenants include restrictions on dividends and capital expenditures, as well as requirements regarding insurance, approval of operating budgets and commercial contracts. These covenants are not anticipated to materially restrict us from borrowing funds or obtaining letters of credit under our credit facilities. None of the above committed bank credit facilities have any defaults or prepayments triggered by changes in credit ratings, or in any way linked to the price of our common stock or any other traded instrument.

For additional information regarding the terms and related interest rates of these credit facilities, please read Note 8 of our consolidated financial statements.

Orion Power Credit Facilities. The credit facilities of Orion Power and its subsidiaries contain various business and financial covenants that are typical for limited or non-recourse project financings. Such covenants include restrictions on dividends and capital expenditures, as well as requirements regarding insurance, approval of operating budgets and commercial contracts. These include covenants that require two of Orion Power's significant subsidiaries which have credit facilities with outstanding borrowings of $1.6 billion as of December 31, 2001, to, among other things, maintain a debt service coverage ratio of at least 1.5 to 1.0 and for Orion Power, which has a $75 million credit facility, to, among other things, maintain a debt service coverage ratio of at least 1.4 to 1.0. One of the subsidiaries may not be able to meet this debt service coverage ratio for the quarter ended June 30, 2002, and Orion Power did not meet the debt service coverage ratio for the quarter ended March 31, 2002. In the event that Orion Power is unable to meet this financial covenant for a second consecutive fiscal quarter it would constitute a default under its credit facility. It is our current intention to arrange for the repayment, refinancing or amendment of these facilities prior to June 30, 2002. If these facilities are not repaid, refinanced or amended prior to that date, and if a waiver is required under either or both of these credit facilities, we believe that we will be able to obtain such a waiver on or prior to June 30, 2002. However, we currently have no assurance that we will be able to obtain such a waiver or amendment from the respective lender groups if required under either or both of these credit facilities.

Orion Bridge Facility. In November 2001, we entered into a $2.2 billion term loan facility to be utilized for the acquisition of Orion Power. In January 2002, the facility was increased to $2.9 billion. On February 19, 2002, in connection with the Orion Power acquisition we borrowed $2.9 billion under the Orion Bridge Facility, which is required to be repaid on or before February 19, 2003.

Potential Future Liquidity Sources. We are currently considering pursuing the following sources of cash to meet our future capital requirements.

Commercial Paper Program. We plan to commence a commercial paper program in 2002, which will be supported by our existing credit facilities. Although we have not yet determined the size of such program, we do not expect that it would exceed $300 million initially, due to market conditions and our current credit ratings. To the extent that we are not successful in placing commercial paper consistently, we will borrow directly under our existing credit facilities.

Debt Securities in the Capital Markets. As part of refinancing the Orion Bridge Facility, we currently expect that we will issue various fixed and floating rate debt securities in 2002 having maturities up to ten years or greater depending upon market conditions. We expect to offer debt securities in the amount of $2.5 to $3.0 billion, depending on market conditions. Our ability to complete such debt offerings in the capital markets will depend on

our future performance and prevailing market conditions. This Form 10-K does not constitute an offer to sell or the solicitation of an offer to buy our debt securities.

Settlement of Indemnification of REPGB Stranded Costs. In December 2001, REPGB and its former shareholders entered into a settlement agreement resolving the former shareholders' stranded cost indemnity obligations under the purchase agreement of REPGB. Under the settlement agreement, the former shareholders paid to REPGB NLG 500 million ($202 million based on an exchange rate of 2.48 NLG per U.S. dollar as of December 31, 2001) in January and February 2002. In addition, under the settlement agreement, the former shareholders waived all rights under the original indemnification agreement to claim distributions from NEA, a 22.5% owned equity investment. We estimate that there will be future distributions from 2002 through 2005 from NEA to REPGB totaling approximately $299 million. For additional information regarding the settlement agreement, our investment in NEA and indemnification of district heat contract obligations, please read Note 13(f) to our consolidated financial statements.

Factors Affecting Our Sources of Cash and Liquidity. As a result of several recent events, including the United States economic recession, the price decline of the common stock of participants in our industry sector and the downgrading of the credit ratings of several of our significant competitors, the availability and cost of capital for our business and the businesses of our competitors have been adversely affected. Any future acquisition or development projects will likely require us to access substantial amounts of capital from outside sources on acceptable terms. We may also 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 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. Increases in our debt levels may adversely affect our credit ratings thereby increasing the cost of our debt. In addition, the capital constraints currently impacting our industry may require our future indebtedness to include terms and or pricing that are more restrictive or burdensome than those of our current indebtedness. This may negatively impact our ability to operate our business, or severely restrict or prohibit distributions from our subsidiaries.

Our ability to arrange financing, including refinancing, and our cost of capital are dependent on the following factors:

- general economic and capital market conditions,
- maintenance of acceptable credit ratings,
- credit availability from banks and other financial institutions,
- investor 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,
- the success of current power generation projects,
- the perceived quality of new power generation projects, and
- provisions of relevant tax and securities laws.

Credit Ratings. Our credit ratings for our senior unsecured debt are as follows:

DATE ASSIGNED	RATING AGENCY	RATI
March 22, 2002	Moody's	Baa3, s
February 14, 2002	Fitch (1)	BBB, negati

March 21, 2002	Standard & Poor's	BBB, s

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(1) Fitch assigned a negative rating outlook to reflect its analysis of our plan for financing and integrating the acquisition of Orion Power.

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 rating agency. 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 commercial contracts and/or guarantees related to our trading, marketing and risk management and hedging operations that require us to maintain an investment grade credit rating. If our credit rating declines below investment grade, we estimate that we could be obligated to provide significant credit support to the counterparties in the form of a pledge of cash collateral, a letter of credit or other similar credit support.

Furthermore, if our credit ratings decline below an investment grade credit rating, our trading partners may refuse to trade with us or trade only on terms less favorable to us. As of December 31, 2001, we had $214 million of margin deposits on energy trading and hedging activities posted as collateral with counterparties. As of December 31, 2001, we had $1.5 billion available under our credit facilities to satisfy future commodity obligations.

OFF-BALANCE SHEET TRANSACTIONS

Construction Agency Agreements. 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. The special purpose entities are not consolidated by us. The special purpose entities have an aggregate financing commitment from equity and debt participants (Investors) of $2.5 billion of which the last $1.1 billion is currently available only if cash collateralized. The availability of the 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 27, 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, but we have generally limited our risk during construction to an amount not in excess of 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 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. We have guaranteed the performance and payment of our subsidiaries' obligations during the construction periods and, if the lease option is exercised, each lessee's obligations during the lease period. At anytime during the construction period or during the lease, we may purchase a facility by paying an amount approximately equal to the outstanding balance plus costs. As of December 31, 2001, the special purpose entities had property, plant and equipment of $428 million, net other assets of $52 million, which were primarily restricted cash, and debt obligations of $465 million. As of December 31, 2001, the special purpose entities had equity from unaffiliated third parties of $15 million. We currently estimate the aggregate cost of the three generating facilities that are currently under construction by the special purpose entities to be approximately $1.8 billon.

Equipment Financing Structure. We, through our subsidiary, REPG, have entered into an agreement with a bank whereby the bank, as owner, entered or will enter into contracts for the purchase and construction of power generation equipment and REPG, or its subagent, acts as the bank's agent in connection with administering the contracts for such equipment. Under the agreement, the bank has agreed to provide up to a maximum aggregate

amount of $650 million. REPG and its subagents must cash collateralize their obligation to administer the contracts. This cash collateral is approximately equivalent to the total payments by the bank for the equipment, interest and other fees. As of December 31, 2001, the bank had assumed contracts for the purchase of eleven turbines, two heat recovery steam generators and one air cooled condenser with an aggregate cost of $398 million. REPG, or its designee, has 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. All costs, including the purchase commitment on the turbines, are the responsibility of the bank. The cash collateral is deposited by REPG or an affiliate into a collateral account with the bank and earns interest at the London inter-bank offered rate (LIBOR) less 0.15%. Under certain circumstances, the collateral deposit or a portion of it will be returned to REPG or its designee. Otherwise, it will be retained by the bank. At December 31, 2001, REPG and its subsidiary had deposited $230 million into the collateral account. The bank's payments for equipment under the contracts totaled $227 million as of December 31, 2001. 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 our collateral deposits were returned to us. As of December 31, 2001, there were equipment contracts with a total contractual obligation of $140 million under which payments during construction totaled $83 million. Currently this equipment is not designated for current planned power generation construction projects. Therefore, we anticipate that we will either purchase the equipment, assist in the remarketing of the equipment or negotiate to cancel the related contracts.

NEW ACCOUNTING PRONOUNCEMENTS AND CRITICAL ACCOUNTING POLICIES

NEW ACCOUNTING PRONOUNCEMENTS

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141 "Business Combinations" (SFAS No. 141) and SFAS No. 142 "Goodwill and

Other Intangible Assets" (SFAS No. 142). 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. SFAS No. 142 provides for a nonamortization approach, whereby 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. We adopted the provisions of each 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. On January 1, 2002, we discontinued amortizing goodwill into our results of operations pursuant to SFAS No. 142. We recognized $32 million of goodwill amortization expense in our statement of consolidated income during 2001, excluding a $19 million write-off of our Communications business goodwill balance which was recorded as goodwill amortization expense (please read Note 16 to our consolidated financial statements). We are in the process of determining further effects of adoption of SFAS No. 142 on our consolidated financial statements, including the review of goodwill and certain intangibles for impairment. We have not completed our review pursuant to SFAS No. 142. However, based on our preliminary review, we believe an impairment of our European Energy segment goodwill is reasonably possible. As of December 31, 2001, net goodwill associated with our European Energy segment is $632 million. We anticipate finalizing our review of goodwill and certain intangibles for our reporting units during 2002. We do not believe impairments of goodwill and certain intangibles, if any, related to our other reporting units will have a material impact on our results of operations or financial position.

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 change in accounting principle in the income statement in the period of adoption. We

plan to adopt SFAS No. 143 on January 1, 2003 and are in the process of determining the effect of adoption on our consolidated 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 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 is not expected to 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 than is currently permitted. We adopted SFAS No. 144 on January 1, 2002.

Effective January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended. The application of SFAS No. 133 is still evolving as the FASB clears issues submitted to the Derivatives Implementation Group for consideration. During the second quarter of 2001, an issue that applies exclusively to the electric industry and allows the normal purchases and normal sales exception for option-type contracts if certain criteria are met was approved by the FASB with an effective date of July 1, 2001. The adoption of this cleared guidance had no impact on our results of operations. Certain criteria of this previously approved guidance were revised in October 2001 and December 2001 and will become effective on April 1, 2002. We are currently in the process of determining the effect of adoption of this revised guidance.

During the third quarter of 2001, the FASB cleared an issue related to application of the normal purchases and normal sales exception to contracts that combine forward and purchased option contracts. The effective date of this guidance is April 1, 2002, and we are currently assessing the impact of this recently cleared issue and do not believe it will have a material impact on our consolidated financial statements.

During the first quarter of 2002, the FASB considered proposed approaches related to identifying and accounting for special-purpose entities. The current proposal being considered by the FASB is likely to limit special purpose entities used by a company for financing and other purpose not being consolidated with its results of operations. One criterion being considered is to require consolidation of a special purposes entity if the equity investments held by third-party owners in the special purposes entity is less than 10% of total capitalization. The FASB likely will not grandfather special purpose entities existing at the date the final interpretation is issued. Special purpose entities in existence at the date of adoption of this interpretation will likely be consolidated by the primary beneficiary. For information regarding special purposes entities affiliated with us, please read " - Liquidity and Capital Resources - Off-Balance Sheet Transactions" and Notes 13(c) and (h) to our consolidated financial statements.

CRITICAL ACCOUNTING POLICIES

A critical accounting policy is one that is both important to the portrayal of our financial condition and results of operations and requires management to make difficult, subjective or complex judgments. The circumstances that make these judgments difficult, subjective and/or complex have to do with the need to make estimates about the effect of matters that are inherently uncertain. Estimates and assumptions about future events and their effects cannot be perceived with certainty. We base our estimates on historical experience and on various other assumptions that are believed to be 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 are the most significant estimates used in the preparation of our consolidated financial statements.

- determination of fair value of trading and marketing assets and liabilities for our energy trading, marketing and price risk management services operations, and non-trading derivative assets and liabilities, including stranded costs obligations related to our European Energy operations (please read " - Trading and Marketing Operations" and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K and Notes 2(d) and 6 to our consolidated financial statements); and

- impairment of long-lived assets and intangibles (please read "European Energy" and Notes 2(f) and 2(q) to our consolidated financial statements).

For a description of all significant accounting policies, please read Note 2 to our consolidated financial statements.

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 and income from our business activities are impacted by market risks. Categories of market risks include exposures to commodity prices through trading and marketing 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.

- 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 framework. We seek to manage our exposures through the use of derivative financial instruments and derivative commodity instruments. 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.

Derivative instruments are financial 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 operations enter into derivative instrument transactions as a means of risk management, optimization of our current power generation asset position, and to take a market position. Derivative instrument transactions are entered into in our non-trading operations to manage and hedge certain exposures, such as exposure to changes in electricity and fuel prices, exposure to interest rate risk on our floating-rate borrowings and foreign currency exposures 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.

TRADING MARKET RISK

Trading and marketing operations often involve market risk associated with managing energy commodities and establishing open positions in the energy markets, primarily on a short-term basis, through derivative instruments (Trading Energy Derivatives). Our trading and marketing businesses depend on price movements and volatility levels to create business opportunities, but these businesses must control risk within authorized limits.

We assess the risk of Trading Energy Derivatives using a value-at-risk (VAR) method, in order to maintain our total exposure within authorized limits. VAR 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 variance/covariance model of VAR, which relies on statistical relationships to describe how changes in different markets can affect a portfolio of instruments with different characteristics and market exposures.

For the VAR numbers reported below, a one-day holding period and a 95% confidence level were used, except for our European trading operations which uses a two-day to five-day holding period. This means that if VAR 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 portfolio in a one-day period would exceed $10 million.

The VAR methodology employs a seasonally adjusted volatility-based approach with the following critical parameters: forward prices and volatility estimates, appropriate market-oriented holding periods and seasonally adjusted correlation estimates. We use the delta approximation method for reporting option positions. The instruments being evaluated could have features that may trigger a potential loss in excess of calculated amounts if changes in commodity prices exceed the confidence level of the model used. An inherent limitation of VAR is that past changes in market risk may not produce accurate predictions of future market risk. Moreover, VAR calculated for a one-day holding period does not fully capture the market risk of positions that cannot be liquidated or offset with hedges within one day. We cannot assure you that market volatility, failure of counterparties to meet their contractual obligations, future transactions or a failure of risk controls will not lead to significant losses from our trading, marketing and risk management activities.

While we believe that our assumptions and approximations are reasonable for calculating VAR, there is no uniform industry methodology for estimating VAR, and different assumptions and/or approximations could produce materially different VAR estimates.

Our VAR limits are set by our Board of Directors, as further discussed below. Violations in overall VAR limits are required to be reported to the Audit Committee of our Board of Directors pursuant to our corporate-wide risk limit parameters. For further discussion on our risk management framework, please read " - Risk Management Structure" below.

The following presents the daily VAR for substantially all of our Trading Energy Derivative positions (in millions).

	2000	2001
As of December 31, ...	$ 15	$ 27
Year Ended December 31:		
Average	6	9
High	36	27
Low	1	3

The following chart presents the daily VAR for substantially all of our Trading Energy Derivatives during 2001 (in millions).

COMBINED DOMESTIC AND EUROPEAN VAR
FOR THE YEAR ENDED DECEMBER 31, 2001

[PERFORMANCE GRAPH]

	YEAR ENDED DECEMBER 31, 2001			
	WHOLESALE	EUROPE	RETAIL	TOTAL
First Quarter	5.040953	0.976000		6.016953
Second Quarter	7.938367	0.838000		8.776367
Third Quarter	4.785587	0.832000		5.617587
Fourth Quarter	8.714555	0.551000	17.785732	27.051287

During the beginning of 2001, the high VAR levels were due to high natural gas and power prices and volatility levels, which continued from late 2000. VAR exposure was lower in the second and third quarters of 2001 due to the significant decline in natural gas and power prices and volatility levels. During the fourth quarter of 2001, VAR levels increased due to increased power marketing activities in ERCOT related to our Retail Energy segment.

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 gross margin. During 2001, 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. 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. 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 Reliant Energy's electricity utility division who did not select another retail electric provider. For a discussion of risk factors affecting our Retail Energy operations, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Certain Factors Affecting Our Future Earnings - Factors Affecting the Results of Our Retail Energy Operations" in Item 7 of this Form 10-K.

Derivative instruments, which we use as economic hedges, create exposure to commodity prices, which we use to 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 derivatives (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, 2001 levels would have decreased the fair value of our Non-trading Energy Derivatives by $52 million, excluding non-trading derivatives liabilities associated with our European Energy segment's stranded cost import contracts.

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, excluding the stranded cost import contracts, 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, we recognized revenues of $8 million in our statement of consolidated income due to hedge ineffectiveness.

Our European Energy segment's stranded cost import contracts have exposure to commodity prices. For information regarding these contracts, please read Notes 6(b) and 13(f) our consolidated financial statements. A decrease of 10% in market prices of energy commodities from their December 31, 2001 levels would result in a loss of earnings of $98 million.

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. We utilize interest-rate swaps in order to hedge a portion of our floating-rate obligations.

Our floating-rate obligations borrowed from third parties aggregated $3.0 billion and $1.1 billion at December 31, 2000 and 2001, respectively. If the floating interest rates were to increase by 10% from December 31, 2001 rates, our combined interest expense to third parties would increase by a total of $0.4 million each month in which such increase continued.

At December 31, 2000 and 2001, we had issued fixed-rate debt to third parties aggregating $67 million and $121 million. As of December 31, 2000 and 2001, fair values were estimated to be equivalent to the carrying amounts of these instruments. 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 would increase by $3 million if interest rates were to decline by 10% from their rates at December 31, 2001.

During 2001, we have entered into interest-rate swaps in order to adjust the interest rate on some of our floating-rate debt to a fixed-rate. As of December 31, 2001, these interest rate swaps had an aggregate notional amount of $200 million and the fair value was a $4 million liability. A decrease of 10% in the interest rate level at December 31, 2001 would increase the fair value of the interest rate swaps by $4 million.

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 European currencies, although the majority of its business is conducted in the Euro and prior to January 2001, the Dutch Guilder. As of December 31, 2001, we had entered into foreign currency swaps and foreign currency forward contracts and had issued Euro-denominated borrowings to hedge our foreign currency exposure of our net European investment. Changes in the value of the foreign currency hedging instruments and Euro - denominated borrowings are recorded as foreign currency translation adjustments as a component of accumulated other comprehensive income (loss) in stockholders' equity. As of December 31, 2000 and 2001, we had recorded a loss of $2 million and $96 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.

As of December 31, 2001, our European Energy segment had entered into transactions to purchase $271 million at fixed exchange rates in order to hedge future fuel purchases payable in U.S. dollars. As of December 31, 2001, the fair value of these financial instruments was a $3 million asset. An increase in the value of the Euro of 10% compared to the U.S. dollar from its December 31, 2001 level would result in loss in the fair value of these foreign currency financial instruments of $27 million.

Our European Energy segment's stranded cost import contracts have foreign currency exposure. An increase of 10% in the U.S. dollar relative to the Euro from their December 31, 2001 levels would result in a loss of earnings of $6 million.

Equity Market Value Risk

We have equity investments, which are classified as "available-for-sale" under SFAS No. 115. As of December 31, 2001, the value of these securities was $12 million. A 10% decline in the market value per share of these securities from December 31, 2001 would result in a loss in fair value of $1 million.

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RISK MANAGEMENT STRUCTURE

We have a risk control framework to limit, monitor, measure and manage the risk in our existing portfolio of assets and contracts and to risk-measure and authorize new transactions. These risks include market, credit, liquidity and operational 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, VAR 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 assesses the adequacy of the risk control organization and policies. The Audit Committee of our Board of Directors meets at least three times a year to:

- approve the risk control organization structure,
- approve the corporate-wide risk control policy,
- monitor compliance with trading limits,

- review significant risk control issues, and
- recommend to our Board of Directors corporate-wide commodity risk limit parameters for trading and marketing activities.

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 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,
- reviews daily position reports for trading and marketing activities,
- recommends adjustments to trading limits, products and policies to the Audit Committee of our Board of Directors,
- approves business segment's detailed policies and procedures,
- allocates Board of Director-approved trading and marketing risk capital limits, including VAR 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, evaluates proposed 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 is headed by a chief risk control officer who has corporate-wide oversight for maintaining consistent application of corporate risk policies within individual business segments. 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 all significant valuation methodologies, assumptions and models;
- evaluates allocation of risk limits within our business segments;
- reviews daily position reports of trading and marketing activities; and
- reviews inherent risks in proposed transactions.

Business Segment Risk Control Organizations. Each of our business segments has a Business Segment Risk Control Organization, which is headed by a risk control officer who reports to the Corporate Risk Control Organization and the business segment's executive management outside of the commercial trading organization. The Business Segment Risk Control Organization:

- 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 Corporate Risk Control Organization, 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 VAR, are reported to the appropriate level of management in the business segment and corporate organizations, 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 the Internal Audit Department with their 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 bankruptcy of customers or counterparties.

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. Broad credit policies and parameters are set by the Risk Oversight Committee. The Business Segment Risk Control Organizations prepare daily analysis of credit exposures. We enter into derivative instruments primarily with counterparties having a minimum investment grade credit rating (i.e., a minimum credit rating for such entity's senior unsecured debt of BBB- for Standard & Poor's and Fitch or Baa3 for Moody's). In addition, we seek to enter into netting agreements that permit us to offset receivables and payables with a given counterparty. We also attempt to enter into agreements that enable us to obtain collateral from a counterparty or to terminate upon the occurrence of credit-related events. We are re-evaluating our current credit risk practices in light of changes in the marketplace, recent corporate failures and higher scrutiny of credit practices by the rating agencies.

It is our policy that all transactions must be within approved counterparty or customer credit limits. For each business segment, counterparty credit limits are established by the applicable segment's credit risk control group. We employ tiered levels of approval authority for counterparty credit limits, with authority increasing from the operating segment's credit analysts through the business segment's risk control officer, the Risk Oversight Committee and our executive management. The Business Segment Risk Control Organization monitors credit exposure daily. The mark-to-market values and cash settlement values for all transactions are compared to the authorized credit threshold for each counterparty. For long-term arrangements, we periodically review the financial condition of these counterparties in addition to monitoring the effectiveness of these contracts in achieving our objectives.

For information regarding our provision related to our energy sales in the California market, please read Note 13(i) to our consolidated financial statements. For information regarding our net provision related to energy sales to Enron which filed a voluntary petition for bankruptcy, please read Note 17 to our consolidated financial statements.

The following table presents the distribution by credit ratings of our total trading and marketing assets and total non-trading derivative assets as of December 31, 2001, after taking into consideration netting and set-off agreements with counterparties within each balance sheet caption (in millions).

CREDIT RATING EQUIVALENT	EXPOSURE	COLLATERAL HELD(3)	EXPOSURE NET OF COLLATERAL	PE EXP C
AAA/Aaa	$ 136	$ --	$ 136	
AA/Aa2	191	--	191	
A/A2	1,049	(4)	1,045	
BBB/Baa2	1,143	(137)	1,006	
BB/Ba2 or lower	251	(26)	225	
Unrated(1)(2)	49	--	49	
	2,819	(167)	2,652	
Less: Credit and other reserves	114	--	114	
	$ 2,705	$ (167)	$ 2,538	

The following table presents credit exposure by maturity for total trading and marketing assets and non-trading derivative assets, net of collateral, as of December 31, 2001 (in millions).

CREDIT RATING EQUIVALENT	0-12 MONTHS	1 YEAR OR GREATER	EXPOSURE NET OF COLLATERAL
AAA/Aaa	$ 95	$ 41	$ 136
AA/Aa2	142	49	191
A/A2	860	185	1,045
BBB/Baa2	653	353	1,006
BB/Ba2 or lower	125	100	225
Unrated(1)(2)	31	18	49
	1,906	746	2,652
Less: Credit and other reserves	69	45	114
	$ 1,837	$ 701	$ 2,538

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(1) For unrated counterparties, we perform financial statement analysis, considering contractual rights and restrictions, and collateral, to create a synthetic credit rating.

(2) 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.

(3) Collateral consists of cash and standby letters of credit.

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, 2000 and 2001, and the related consolidated statements of income, stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2001. Our audits also included the financial statement schedule listed in the Index at Item 14(a)(2). These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule 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, 2000 and 2001, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 6 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities in 2001.

As discussed in Note 1 to the consolidated financial statements, the accompanying consolidated financial statements have been restated.

DELOITTE & TOUCHE LLP

Houston, Texas
March 28, 2002
(July 3, 2002 as to the effects of the
restatement discussed in Note 1)

RELIANT RESOURCES, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED INCOME
(THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)
(AS RESTATED, SEE NOTE 1)

	YEAR ENDED DECEMBER	
	1999	2000
REVENUES	$ 6,539,202	$ 18,721,697
EXPENSES:		
Fuel and cost of gas sold	3,572,124	10,554,498

Purchased power	2,687,906	6,809,188
Operation and maintenance	135,620	435,006
General, administrative and development	100,480	291,661
Depreciation and amortization	28,584	193,682
Total	6,524,714	18,284,035
OPERATING INCOME	14,488	437,662
OTHER (EXPENSE) INCOME:		
Interest expense	(8,795)	(42,337)
Interest income	--	17,732
Interest (expense) income - affiliated companies, net	(9,802)	(172,269)
Gains (losses) from investments, net	15,972	(16,509)
Income of equity investment of unconsolidated subsidiaries	20,805	42,860
Gain on sale of development project	--	18,011
Other, net	(6,062)	5,963
Total other income (expense)	12,118	(146,549)
INCOME BEFORE INCOME TAXES, CUMULATIVE EFFECT OF ACCOUNTING CHANGE AND EXTRAORDINARY ITEM	26,606	291,113
INCOME TAX EXPENSE	2,560	88,593
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE AND EXTRAORDINARY ITEM	24,046	202,520
Cumulative effect of accounting change, net of tax	--	--
Extraordinary item, net of tax	--	7,445
NET INCOME	$ 24,046	$ 209,965
BASIC AND DILUTED EARNINGS PER SHARE:		
Income before cumulative effect of accounting change		
Cumulative effect of accounting change, net of tax		
Net income		

See Notes to the Company's Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(THOUSANDS OF DOLLARS)
(AS RESTATED, SEE NOTE 1)

	DECEMBE
	2000

ASSETS	
CURRENT ASSETS:	
Cash and cash equivalents	$ 89,755
Restricted cash	50,000
Accounts and notes receivable, principally customer, net	1,811,355
Accounts and notes receivable - affiliated companies, net	--
Inventory	99,445
Stranded costs settlement receivable	--
Trading and marketing assets	4,290,803
Non-trading derivative assets	--
Margin deposits on energy trading and hedging activities	521,004
Collateral for electric generating equipment	--
Prepayments and other current assets	206,334
Total current assets	7,068,696
PROPERTY, PLANT AND EQUIPMENT, NET	4,049,495
OTHER ASSETS:	
Goodwill, net	1,006,782
Air emissions regulatory allowances and other intangibles, net	283,952
Notes receivable - affiliated companies, net	--
Equity investments in unconsolidated subsidiaries	108,727
Trading and marketing assets	544,909
Non-trading derivative assets	--
Stranded costs indemnification receivable	--
Accumulated deferred income taxes	--
Collateral for electric generating equipment	84,879
Other	327,952
Total other assets	2,357,201
TOTAL ASSETS	$ 13,475,392
LIABILITIES AND STOCKHOLDERS' EQUITY	
CURRENT LIABILITIES:	
Current portion of long-term debt	$ 591
Short-term borrowings	126,175
Accounts payable, principally trade	2,083,556
Accounts and notes payable - affiliated companies, net	1,321,120
Trading and marketing liabilities	4,272,771
Non-trading derivative liabilities	--
Margin deposits from customers on energy trading and hedging activities	284,603
Accumulated deferred income taxes	--
Other	391,592
Total current liabilities	8,480,408
OTHER LIABILITIES:	
Accumulated deferred income taxes	31,181
Notes payable - affiliated companies, net	647,499
Trading and marketing liabilities	530,263
Non-trading derivative liabilities	--
Major maintenance reserve	19,899
Non-derivative stranded costs liability	--
Benefit obligations	44,413
Other	497,543

Total other liabilities	1,770,798
LONG-TERM DEBT	891,736
COMMITMENTS AND CONTINGENCIES (NOTE 13)	
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; 240,000,000 and 299,804,000 issued and outstanding, respectively)	1
Additional paid-in capital	2,336,993
Treasury stock at cost, 0 and 11,000,000 shares	--
Retained earnings	--
Accumulated other comprehensive loss	(4,544)
Stockholders' equity	2,332,450
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 13,475,392

See Notes to the Company's Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS
(THOUSANDS OF DOLLARS)

	YEAR ENDED DECEMBER	
	1999	2000
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 24,046	$ 209,965
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	28,583	193,682
Deferred income taxes	15,556	(27,476)
Net trading and marketing assets and liabilities	(11,703)	(3,984)
Net non-trading derivative assets and liabilities	--	--
Curtailment and related benefit enhancement	--	--
Contributions of marketable securities to charitable foundation	--	15,172
Impairment of marketable equity securities	--	26,504
Undistributed loss (income) of unconsolidated subsidiaries	793	(24,931)
Gain on sale of development project	--	(18,011)
Stranded cost indemnification settlement gain	--	--
Cumulative effect of accounting change	--	--
Extraordinary item	--	(7,445)
Other, net	(15,948)	(2,034)

Changes in other assets and liabilities:		
Restricted cash	--	(50,000)
Accounts and notes receivable, net	(225,257)	(1,174,918)
Accounts receivable/payable - affiliated companies, net	32,939	(168,692)
Inventory	69,076	(9,468)
Collateral for electric generating equipment, net	--	(84,879)
Margin deposits on energy trading and hedging activities, net	(59,467)	(206,480)
Prepaid lease obligation	--	--
Proceeds from sale of debt securities	--	123,428
Other current assets	(11,905)	(92,719)
Other assets	(8,199)	(103,692)
Accounts payable	274,054	1,485,925
Taxes accrued	(21,450)	49,716
Other current liabilities	23,974	209,216
Other liabilities	(80,038)	(11,337)
Net cash provided by (used in) operating activities	35,054	327,542
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(293,197)	(933,180)
Payment of business purchase obligation	--	(981,789)
Business acquisitions, net of cash acquired	(1,065,013)	(2,121,408)
Proceeds from sale-leaseback transactions	--	1,000,000
Investments in unconsolidated subsidiaries	(36,582)	(5,755)
Other, net	(11,680)	28,830
Net cash used in investing activities	(1,406,472)	(3,013,302)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term debt	61,601	770,009
Proceeds from issuance of stock, net	--	--
Purchase of treasury stock	--	--
Payments of long-term debt	--	(307,201)
(Decrease) increase in short-term borrowings, net	(18,591)	(31,906)
Increase (decrease) in notes with affiliated companies, net	1,306,576	1,219,946
Contributions from owner	235,877	1,094,259
Distribution to owner	(170,211)	--
Other, net	(7,691)	(23,951)
Net cash provided by financing activities	1,407,561	2,721,156
EFFECT OF EXCHANGE RATE CHANGES ON CASH AND CASH EQUIVALENTS	460	5,088
NET INCREASE IN CASH AND CASH EQUIVALENTS	36,603	40,484
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	12,668	49,271
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 49,271	$ 89,755
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash Payments:		
Interest (net of amounts capitalized)	$ 37,126	$ 205,103
Income taxes	16,496	72,784

See Notes to the Company's Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED
STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(THOUSANDS OF DOLLARS)
(AS RESTATED, SEE NOTE 1)

	COMMON STOCK	TREASURY STOCK	ADDITI PAID CAPI
BALANCE DECEMBER 31, 1998			
COMPREHENSIVE INCOME:			
Net income			
Contributions from owner			
Distribution to owner			
Other comprehensive loss:			
Unrealized loss on available-for-sale securities, net of tax of $0.4 million			
Foreign currency translation adjustments			
Comprehensive income			
BALANCE DECEMBER 31, 1999			
COMPREHENSIVE INCOME:			
Net income			
Contributions from owner			
Transfer to common stock and additional paid-in capital	$ 1		$ 2,33
Other comprehensive income (loss):			
Foreign currency translation adjustments			
Additional minimum non-qualified pension liability adjustment, net of tax of $0.4 million ...			
Reclassification adjustment for impairment loss on available-for-sale securities realized in net income, net of tax of $9 million			
Unrealized loss on available-for-sale securities, net of tax of $1 million			
Comprehensive income			
BALANCE DECEMBER 31, 2000	1		2,33
Net income			
Contributions from owner			1,78
Purchases of treasury stock		(189,460)	
Majority owner effect of treasury stock purchases			(4
IPO proceeds, net	60		1,69
Other comprehensive income (loss):			
Foreign currency translation adjustments, net of tax of $98 million			
Changes in minimum non-qualified pension liability, net of tax of $4 million			
Cumulative effect of adoption of SFAS No. 133, net of tax of $236 million			
Deferred gain from cash flow hedges, net of tax of $228 million			

Reclassification of net deferred gain from cash flow hedges into net income, net of tax of $24 million			
Unrealized gain on available-for-sale securities, net of tax of $9 million			
Reclassification adjustments for gains on sales of available-for-sale securities realized in income, net of tax of $5 million			
Comprehensive income			
BALANCE DECEMBER 31, 2001	$ 61	$ (189,460)	$ 5,77

	UNREALIZED (LOSS) GAIN ON AVAILABLE FOR SALE SECURITIES	DEFERRED DERIVATIVE GAINS (LOSSES)	FOREI CURRE TRANSL ADJUST
BALANCE DECEMBER 31, 1998	$ (16,004)		
COMPREHENSIVE INCOME:			
Net income			
Contributions from owner			
Distribution to owner			
Other comprehensive loss:			
Unrealized loss on available-for-sale securities, net of tax of $0.4 million	(1,224)		
Foreign currency translation adjustments			$
Comprehensive income			
BALANCE DECEMBER 31, 1999	(17,228)		
COMPREHENSIVE INCOME:			
Net income			
Contributions from owner			
Transfer to common stock and additional paid-in capital			
Other comprehensive income (loss):			
Foreign currency translation adjustments			(
Additional minimum non-qualified pension liability adjustment, net of tax of $0.4 million ...			
Reclassification adjustment for impairment loss on available-for-sale securities realized in net income, net of tax of $9 million	17,228		
Unrealized loss on available-for-sale securities, net of tax of $1 million	(2,264)		
Comprehensive income			
BALANCE DECEMBER 31, 2000	(2,264)		(
Net income			
Contributions from owner			
Purchases of treasury stock			
Majority owner effect of treasury stock purchases			
IPO proceeds, net			
Other comprehensive income (loss):			
Foreign currency translation adjustments, net of tax of $98 million			(9

Changes in minimum non-qualified pension liability, net of tax of $4 million			
Cumulative effect of adoption of SFAS No. 133, net of tax of $236 million		$ (459,944)	
Deferred gain from cash flow hedges, net of tax of $228 million		427,994	
Reclassification of net deferred gain from cash flow hedges into net income, net of tax of $24 million		(32,544)	
Unrealized gain on available-for-sale securities, net of tax of $9 million	16,984		
Reclassification adjustments for gains on sales of available-for-sale securities realized in income, net of tax of $5 million	(8,670)		
Comprehensive income			
BALANCE DECEMBER 31, 2001	$ 6,050	$ (64,494)	$ (9

	TOTAL ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	TOTAL STOCKHOLDER'S EQUITY	COMPREH INC (LO
BALANCE DECEMBER 31, 1998	$ (16,004)	$ 652,035	
COMPREHENSIVE INCOME:			
Net income		24,046	$
Contributions from owner		235,877	
Distribution to owner		(170,211)	
Other comprehensive loss:			
Unrealized loss on available-for-sale securities, net of tax of $0.4 million	(1,224)	(1,224)	
Foreign currency translation adjustments	162	162	
Comprehensive income			$
BALANCE DECEMBER 31, 1999	(17,066)	740,685	
COMPREHENSIVE INCOME:			
Net income		209,965	$ 2
Contributions from owner		1,369,278	
Transfer to common stock and additional paid-in capital		--	
Other comprehensive income (loss):			
Foreign currency translation adjustments	(1,726)	(1,726)	
Additional minimum non-qualified pension liability adjustment, net of tax of $0.4 million ...	(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	
Unrealized loss on available-for-sale securities, net of tax of $1 million	(2,264)	(2,264)	
Comprehensive income			$ 2
BALANCE DECEMBER 31, 2000	(4,544)	2,332,450	
Net income		557,451	$ 5

Contributions from owner		1,787,311	
Purchases of treasury stock		(189,460)	
Majority owner effect of treasury stock purchases		(43,149)	
IPO proceeds, net		1,696,074	
Other comprehensive income (loss):			
Foreign currency translation adjustments, net of tax of $98 million	(94,066)	(94,066)	(
Changes in minimum non-qualified pension liability, net of tax of $4 million	(6,799)	(6,799)	
Cumulative effect of adoption of SFAS No. 133, net of tax of $236 million	(459,944)	(459,944)	(4
Deferred gain from cash flow hedges, net of tax of $228 million	427,994	427,994	4
Reclassification of net deferred gain from cash flow hedges into net income, net of tax of $24 million	(32,544)	(32,544)	(
Unrealized gain on available-for-sale securities, net of tax of $9 million	16,984	16,984	
Reclassification adjustments for gains on sales of available-for-sale securities realized in income, net of tax of $5 million	(8,670)	(8,670)	
Comprehensive income			$ 4
BALANCE DECEMBER 31, 2001	$ (161,589)	$ 5,983,632	

See Notes to the Company's Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE THREE YEARS ENDED DECEMBER 31, 1999, 2000 AND 2001

(1) BACKGROUND AND BASIS OF PRESENTATION

On July 27, 2000, Reliant Energy, Incorporated (Reliant Energy) announced its intention to form a company, Reliant Resources, Inc. (Reliant Resources), to own and operate a substantial portion of its unregulated operations and to offer no more than 20% of the common stock of Reliant Resources in an initial public offering. Reliant Resources and its subsidiaries are collectively referred to herein as the "Company." 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. Reliant Energy expects to distribute the remaining common stock of Reliant Resources owned by Reliant Energy or its successors to its shareholders (Distribution) in the summer of 2002. The Distribution is subject to the declaration of the Distribution by the Board of Directors of Reliant Energy, market and other conditions, and government actions and approvals. There can be no assurances that the Distribution will be completed as described or within the periods outlined above. Reliant Energy, together with its subsidiaries, is a diversified international energy services company consisting of regulated and unregulated energy operations. For information regarding the IPO, see Note 9(a).

The unregulated operations included in the consolidated financial statements of Reliant Resources for 1999 and 2000 consist of Reliant Energy's, or its direct and indirect subsidiaries', unregulated power generation and related energy trading, marketing, power 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 1999 and 2000, these operations were conducted by Reliant Energy and its direct and indirect subsidiaries. On August 9, 2000, Reliant Energy formed Reliant Resources, a Delaware corporation, as a wholly owned subsidiary. Reliant Resources was incorporated with 1,000 shares of common stock. Effective December 31, 2000, Reliant Energy consolidated its unregulated operations under Reliant Resources (Consolidation). A subsidiary of Reliant Energy, Reliant Energy Resources Corp. (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, Reliant Energy 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 Reliant Energy were accounted for as a reorganization of entities under common control.

RESTATEMENT

On May 9, 2002, Reliant Resources determined that it had engaged in same-day commodity trading transactions involving purchases and sales with the same counterparty for the same volume at substantially the same price, which the personnel who effected these transactions apparently did so with the sole objective of increasing volumes. Reliant Resources commenced a review to quantify the amount and assess the impact of these trades (round trip trades). The Audit Committees of each of the Board of Directors of Reliant Resources and Reliant Energy (Audit Committees) also directed an internal investigation by outside legal counsel, with assistance by outside accountants, of the facts and circumstances relating to the round trip trades and related matters.

The Company currently reports all trading, marketing and risk management services transactions on a gross basis with such transactions being reported in revenues and expenses except primarily for financial gas transactions such as swaps. Therefore, the round trip trades were reflected in both the Company's revenues and expenses. The round trip trades should not have been recognized in revenues or expenses (i.e. they should have been reflected on a net basis). However, since the round trip trades were done at the same volume and substantially the same price, they had no impact on the Company's reported cash flows, operating income or net income.

Based on the Company's review, the Company determined that it engaged in such round trip trades in 1999, 2000 and 2001. The results of the Audit Committees' investigation were consistent with the results of the Company's review. The round trip trades were for 30 million megawatt hours (MWh) of power and 182 billion cubic feet (Bcf) in 1999, 30 million MWh of power in 2000, and 74 million MWh of power and 46 Bcf of natural gas in 2001. On May 13, 2002, the Company previously announced its preliminary findings of round trip trades which had identified 30 million MWh of power in 1999, 30 million MWh of power in 2000, and 78 million MWh of power and 45 Bcf of natural gas in 2001. In addition to the round trip trades reported on May 13, 2002, the Company's review, also identified an additional transaction in 1999 involving 182 Bcf of natural gas totaling $364 million, which based on available information, the Company believes was also recorded with the sole objective of increasing volumes but also resulted in increased revenues and fuel and cost of gas sold expense.

In the course of the Company's review, the Company also identified and determined to record on a net basis several transactions for energy related services (not involving round trip trades) that totaled $85 million over the three year period ended December 31, 2001. These transactions were originally recorded on a gross basis.

During 1999, 2000 and 2001, these transactions, referred to above, collectively had the effect of increasing revenues, fuel and cost of gas sold expense and purchased power expense as follows:

	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
		(IN MILLIONS)	
Revenues	$ 1,417	$ 1,070	$ 3,902
Fuel and cost of gas sold expense	376	27	208
Purchase power expense	1,041	1,043	3,694

In addition, during the May 2001 through September 2001 time frame, the Company entered into four structured transactions involving a series of forward or swap contracts to buy and sell an energy commodity in 2001 and to buy and sell an energy commodity in 2002 or 2003 (four structured transactions). The four structured transactions were intended to increase future cash flow and earnings and to increase certainty associated with future cash flow and earnings, albeit at the expense of 2001 cash flow and earnings. Each series of contracts in a structure were executed contemporaneously with the same counterparty and were for the same commodities, quantities and locations. The contracts in each structure were offsetting in terms of physical attributes. The transactions that settled in 2001 were previously recorded on a gross basis with such transactions being reported in revenues and expenses which resulted in $1.5 billion of revenues, $364 million in fuel and cost of gas sold and $1.2 billion of purchased power expense being recognized during the period from May 2001 through December 31, 2001. Having further reviewed the transactions, the Company now believes these transactions should have been accounted for on a net basis.

During the fourth quarter of 2000, two power generation swap contracts with a fair value of $261 million were terminated and replaced with a substantially similar contract providing for physical delivery and designated to hedge electric generation. The termination of the original contracts and execution of the replacement contract represented a substantive modification to the original contract. As a result, upon termination of the original contracts, a contractual liability representing the fair value of the original contracts and a deferred asset of equal amount should have been recorded. As of January 1, 2001, in connection with the adoption of Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended, the deferred asset should have been recorded as a transition adjustment to other comprehensive loss. The liability and transition adjustment should have been amortized on a straight-line basis over the term of the power generation contract replacing the terminated power generation contracts (through May 2004). The Company previously did not give accounting recognition to these transactions. As a result, the Company has restated its Consolidated Balance Sheets as of December 31, 2000 and 2001 and the Statement of Consolidated Stockholders' Equity and Comprehensive Income for the year ended December 31, 2001, to appropriately account for these transactions as described above. The restatement had no impact on the Company's reported consolidated cash flows, operating income or net income.

The consolidated financial statements for 1999, 2000 and 2001 have been restated from amounts previously reported to reflect all of the transactions described herein. In addition, the unaudited quarterly financial data for the interim periods ended March 31, 2001, June 30, 2000 and 2001, and September 30, 2000 and 2001 have been restated from amounts previously reported to reflect all of the transactions described herein. The unaudited restated condensed quarterly financial statement information for the quarters ended March 31, 2001, June 30, 2000 and 2001, September 30, 2000 and 2001, and December 31, 2000 and 2001 have been included in Note 15. The restatement had no impact on previously reported consolidated cash flows, operating income or net income. A summary of the principal effects of the restatement are as follows for 1999, 2000 and 2001: (Note - Those line items for which no change in amounts are shown were not affected by the restatement.)

	YEAR ENDED DECEMBER 31, 1999	
	AS RESTATED	AS PREVIOUSLY REPORTED
	(IN MILLIONS)	
Revenues................................	$ 6,539	$ 7,956
Expenses:		
Fuel and cost of gas sold...........	3,572	3,948
Purchased power.....................	2,688	3,729
Other expenses......................	265	265
Total............................	6,525	7,942
Operating Income........................	14	14
Other Income, net.......................	12	12
Income Tax Expense......................	(2)	(2)
Net Income..............................	$ 24	$ 24

	YEAR ENDED DECEMBER 31, 2000	
		AS PREVIOUSLY

	AS RESTATED	REPORTED
	(IN MILLIONS)	
Revenues	$ 18,722	$ 19,792
Expenses:		
Fuel and cost of gas sold	10,555	10,582
Purchased power	6,809	7,852
Other expenses	920	920
Total	18,284	19,354
Operating Income	438	438
Other Expense, net	(147)	(147)
Income Tax Expense	(88)	(88)
Income Before Extraordinary Gain	203	203
Extraordinary Gain	7	7
Net Income	$ 210	$ 210

	DECEMBER 31, 2000	
	AS RESTATED	AS PREVIOUSLY REPORTED
	(IN MILLIONS)	
ASSETS		
CURRENT ASSETS:		
Other current assets	$ 206	$ 130
Other	6,863	6,863
Total current assets	7,069	6,993
OTHER ASSETS:		
Other noncurrent assets	328	143
Property, plant and equipment and other	6,078	6,078
Total other assets	6,406	6,221
TOTAL ASSETS	$ 13,475	$ 13,214
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Other current liabilities	$ 392	$ 316
Other	8,088	8,088
Total current liabilities	8,480	8,404
OTHER LIABILITIES:		
Other noncurrent liabilities	498	313
Other	1,273	1,273

Total other liabilities	1,771	1,586
LONG-TERM DEBT	892	892
STOCKHOLDERS' EQUITY	2,332	2,332
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 13,475	$ 13,214

	YEAR ENDED DECEMBER 31, 2001	
	AS RESTATED	AS PREVIOUSLY REPORTED
	(IN MILLIONS)	
Revenues	$ 31,130	$ 36,546
Expenses:		
Fuel and cost of gas sold	15,234	15,805
Purchased power	13,889	18,734
Other expenses	1,245	1,245
Total	30,368	35,784
Operating Income	762	762
Other Income, net	64	64
Income Tax Expense	(272)	(272)
Income Before Cumulative Effect of Accounting Change	554	554
Cumulative effect of accounting change, net of tax	3	3
Net Income	$ 557	$ 557

	DECEMBER 31, 2001	
	AS RESTATED	AS PREVIOUSLY REPORTED
	(IN MILLIONS)	
ASSETS		
CURRENT ASSETS	$ 4,745	$ 4,745
OTHER ASSETS:		
Accumulated deferred income taxes	46	8
Property, plant and equipment and other	7,501	7,501

Total other assets	7,547	7,509
TOTAL ASSETS	$ 12,292	$ 12,254
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Non-trading derivative liabilities	$ 399	$ 323
Accumulated deferred income taxes	37	64
Other	3,200	3,200
Total current liabilities	3,636	3,587
OTHER LIABILITIES:		
Non-trading derivative liabilities	639	530
Other	1,165	1,165
Total other liabilities	1,804	1,695
LONG-TERM DEBT	868	868
STOCKHOLDERS' EQUITY:		
Preferred stock	-	-
Common Stock	-	-
Additional paid-in capital	5,777	5,777
Treasury stock	(189)	(189)
Retained earnings	557	557
Accumulated other comprehensive income	(161)	(41)
Stockholders' equity	5,984	6,104
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 12,292	$ 12,254

The restatement did not impact earnings per share for 2001 or the Statements of Consolidated Cash Flows for 1999, 2000 and 2001.

In addition to the round trip trades described above, the Company's review and the Audit Committees' investigation also considered other transactions executed on the same day at the same volume, price and delivery terms and with the same counterparty. These transactions were executed in the normal course of the Company's trading and marketing activities, and were historically reported on a gross basis, and were not material.

Beginning with the quarter ended September 30, 2002, the Company will report all energy trading and marketing activities on a net basis in the Statements of Consolidated Income pursuant to Emerging Issues Task Force Issue No. 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities".

BASIS OF PRESENTATION

The accompanying consolidated financial statements for 1999 and 2000 are presented on a carve-out basis and include the historical operations of the Company. These financial statements have been prepared from Reliant Energy's historical accounting records.

The Statements of Consolidated Income include all revenues and costs directly attributable to the Company, including costs for facilities and costs for functions and services performed by centralized Reliant Energy organizations and directly charged to the Company based on usage or other allocation factors. The results of operations in these Consolidated Financial Statements also include general corporate expenses allocated by Reliant Energy to the Company. 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 the Company had been operated as a separate entity.

The Company's financial reporting segments include the following: Wholesale Energy, European Energy, Retail Energy and Other Operations. 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, which was formed in the fourth quarter of 1999, operates power generation facilities in the Netherlands and conducts wholesale energy trading and power origination activities in Europe. The Retail Energy segment includes the Company's retail electric operations. This segment provides customized, integrated energy services to large commercial, industrial and institutional customers and electricity and related services to residential and small commercial customers in Texas. In addition, Retail Energy historically included billing and remittance services provided to Reliant Energy's regulated electric utility and two of its natural gas utilities. Such services will not be provided to Reliant Energy's electric utility and its natural gas utilities after December 31, 2001. Retail Energy charged the regulated electric and gas utilities for the services provided to these utilities at the Company's cost. The Other Operations segment includes unallocated general corporate expenses and non-operating investments.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) RECLASSIFICATIONS AND USE OF ESTIMATES.

Some amounts from the previous years have been reclassified to conform to the 2001 presentation of financial statements. These reclassifications do not affect earnings.

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.

(b) 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 Notes 6, 13(i) and 17. The Company is also subject to risks, among others, relating to the timing of the implementation of the business separation plan of Reliant Energy, supply and prices of fuel and electricity, effects of competition, changes in interest rates, results of financing efforts, operation of deregulating power markets, seasonal weather patterns, technological obsolescence and the regulatory environment in the United States and Europe. In addition, the Company is subject to risks relating to the reliability of the systems, procedures and other infrastructure necessary to operate the Company's retail electric business.

(c) PRINCIPLES OF CONSOLIDATION.

The accounts of the Company and its wholly owned and majority owned subsidiaries are included in the Consolidated Financial Statements. All significant intercompany transactions and balances are eliminated in consolidation. The Company uses the equity method of accounting for investments in entities in which the Company has an ownership interest between 20% and 50% and exercises significant influence. For additional information regarding investments recorded using the equity method of accounting, see Note 7. Other investments, excluding marketable securities, are generally carried at cost. The results of the Company's European Energy segment are consolidated on a one-month-lag basis due to the availability of financial information. The Company has made adjustments to the European Energy segment's accounts to include the effect for the settlement of an indemnity for certain energy obligations in December 2001 (see Note 13(f)).

(d) REVENUES.

The Company records gross revenue for energy sales and services related to its electric power generation facilities under the accrual method and these revenues generally are recognized upon delivery. Energy sales and services related to its electric power generation facilities not billed by month-end are accrued based upon estimated energy and services delivered. Domestic electric power and other energy services are sold at market-based prices through existing power exchanges or through third-party contracts. Prior to January 1, 2001, energy revenues related to the Company's power generation facilities in Europe were determined under a regulated pricing structure, which included compensation for the cost of fuel, capital and operation and maintenance expenses. The wholesale electric

market in the Netherlands opened to competition on January 1, 2001. Accordingly, beginning in 2001, electric power and other energy services in Europe are sold at market-based prices or through third-party contracts.

The Company records gross revenue for energy sales and services to retail customers except, for sales to large contracted commercial, industrial and institutional customers, under the accrual method and these revenues generally are recognized upon delivery.

The Company's energy trading, marketing, power origination and risk management services activities and contracted sales of electricity to large commercial, industrial and institutional customers 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 market value in revenues upon contract execution. The net changes in their fair values are recognized in the Statement of Consolidated Income as revenues in the period of change. Trading and marketing revenues related to the physical sale of natural gas, electric power and other energy related commodities are recorded on a gross basis in the delivery period. 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 6.

The gains and losses related to financial instruments and contractual commitments qualifying and designated as hedges related to the sale of electric power and purchase of fuel are recognized in the same period as the settlement of the underlying physical transaction. These realized gains and losses are included in operating revenues and operating expenses in the Statements of Consolidated Income. For additional discussion, see Note 6.

(e) GENERAL, ADMINISTRATIVE AND DEVELOPMENT EXPENSES.

The general, administrative and development expenses in the Statements of Consolidated Income include employee related costs of the trading, marketing, power origination and risk management services operations, corporate and administrative services (including management services, financial and tax accounting, cash management and treasury support, legal, information technology system support, office management and human resources); business development costs; and certain benefit costs.

(f) LONG-LIVED ASSETS AND INTANGIBLES.

The Company records property, plant and equipment at historical cost. The Company recognizes repair and maintenance costs incurred in connection with planned major maintenance, such as turbine and generator overhauls, control system upgrades and air conditioner replacements, under the "accrue in advance" method for its 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, the Company estimates the costs of planned major maintenance and accrues the related expense over the maintenance cycle. As of December 31, 2000 and 2001, the Company's major maintenance reserve was $27 million and $19 million, respectively, of which $7 million and $2 million, respectively, were included in other current liabilities. The Company expenses all other repair and maintenance costs as incurred. For power generation operations acquired or developed subsequent to January 1, 2000, the Company expenses all repair and maintenance costs as incurred, including planned major maintenance. Property, plant and equipment includes the following:

	ESTIMATED USEFUL LIVES (YEARS)	DECEMBER 31, 2000	DECEMBER 31, 2001
		(IN MILLIONS)	
Electric generation facilities	10 - 40	$ 2,794	$ 2,828
Building and building improvements	15 - 20	12	14
Other	3 - 10	76	164
Land and land improvements		141	147
Assets under construction		1,177	1,682
Total		4,200	4,835
Accumulated depreciation		(151)	(276)

Property, plant and equipment, net	$ 4,049	$ 4,559

The Company records goodwill for the excess of the purchase price over the fair value assigned to the net assets of an acquisition. Historically, goodwill is amortized on a straight-line basis over 5 to 40 years. See Notes 2(q) and 5 and the following table for additional information regarding goodwill and the related amortization periods.

ACQUISITION	AMORTIZATION PERIOD (YEARS)	DECEMBER 31, 2000	2001
		(IN MILLIONS)	
Reliant Energy Mid-Atlantic Power Holdings, LLC	35	$ 7	$
Reliant Energy Power Generation Benelux N.V	30	897	8
Florida Generation Plant	35	2	
California Generation Plants	30	70	
Reliant Energy Services, Inc.	40	131	1
Other	5 - 15	59	
Total		1,166	1,1
Accumulated amortization		(52)	(
Foreign currency exchange impact		(107)	(1
Total goodwill, net		$ 1,007	$ 8

The Company recognizes specifically identifiable intangibles, including air emissions regulatory allowances, water rights and permits, when specific rights and contracts are acquired. The Company amortizes air emissions regulatory allowances primarily on a units-of-production basis as utilized. The Company amortizes other acquired intangibles on a straight-line basis over the lesser of their contractual or estimated useful lives that range between 20 and 35 years.

The Company periodically evaluates long-lived assets, including property, plant and equipment, goodwill and specifically identifiable 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 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. During 2001, the Company determined equipment and goodwill associated with the Communications business was impaired and accordingly recognized $22 million of fixed asset impairments and $19 million of goodwill impairments (see Note 16). For discussion of goodwill impairment analysis in 2002, see Note 2(q).

During December 2001, the Company evaluated its European Energy business segment's long-lived assets and goodwill for impairment. As of December 31, 2001, pursuant to Statement of Financial Accounting Standards (SFAS) No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" (SFAS No. 121), no impairment had been indicated. For discussion of goodwill impairment analysis in 2002, see Note 2(q).

(g) DEPRECIATION AND AMORTIZATION EXPENSE.

Depreciation is computed using the straight-line method based on economic lives. Other amortization expense includes amortization of air emissions regulatory allowances and other intangibles. The 2001 goodwill amortization expense includes the $19 million in goodwill impairment related to the Communications business (see Note 16). The following table presents depreciation, goodwill amortization and other amortization expense for 1999, 2000 and 2001.

	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
		(IN MILLIONS)	
Depreciation expense	$ 18	$ 105	$ 15
Goodwill amortization expense	11	35	5
Other amortization expense	--	54	4
Total depreciation and amortization expense	$ 29	$ 194	$ 24

(h) 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 1999, 2000 and 2001, the Company capitalized interest of $8 million, $35 million and $59 million, respectively.

(i) INCOME TAXES.

The Company is included in the consolidated income tax returns of Reliant Energy. The Company calculates its income tax provision on a separate return basis under a tax sharing agreement with Reliant 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 some state income taxes are payable to or receivable from Reliant Energy. Unremitted earnings from the Company's foreign operations are deemed to be permanently reinvested in foreign operations. For additional information regarding income taxes, see Note 12.

(j) CASH AND RESTRICTED CASH.

The Company records as cash and cash equivalents all highly liquid short-term investments with original maturities of three months or less. As of December 31, 2001, the Company has 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. For additional discussion regarding REMA's lease transactions, see Note 13(c).

(k) ALLOWANCE FOR DOUBTFUL ACCOUNTS.

Accounts and notes receivable, principally from customers, on the Consolidated Balance Sheets are net of an allowance for doubtful accounts of $51 million and $90 million at December 31, 2000 and 2001, respectively. The provision for doubtful accounts in the Statements of Consolidated Income for 1999, 2000 and 2001 was $1 million, $43 million and $38 million, respectively. In addition, during 2001, the Company wrote-off $15 million of receivables for refunds related to energy sales in California and $88 million related to energy sales to Enron Corp. and its affiliates (Enron) which filed a voluntary petition for bankruptcy during the fourth quarter of 2001. For information regarding the provision against receivable balances related to energy sales in the California market and to Enron, see Notes 13(i) and 17, respectively.

(l) 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 as discussed in Note 6. Below is a detail of inventory:

	DECEMBER 31,	
	2000	2001
	(IN MILLIONS)	
Materials and supplies	$ 44	$ 65
Coal	10	35
Natural gas	16	41
Heating oil	29	33
Total inventory	$ 99	$ 174

(m) INVESTMENT IN OTHER DEBT AND EQUITY SECURITIES.

As of December 31, 2000 and 2001, the Company held marketable equity securities of $5 million and $12 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), the Company reports "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, 2000, the accumulated unrealized loss, net of tax, relating to these equity securities was $2 million. At December 31, 2001, the Company had an accumulated unrealized gain, net of tax, relating to these securities of $6 million.

During 2000, pursuant to SFAS No. 115, the Company 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 determination 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 the Company's investment in these securities continuing to be below the Company's cost basis, caused management to believe the decline in fair value of these "available-for-sale" securities to be other than temporary.

In addition, the Company has held debt and equity securities classified as "trading." In accordance with SFAS No. 115, the Company reports "trading" securities at estimated fair value in the Company's Consolidated Balance Sheets and any unrealized holding gains and losses are recorded as gains (losses) from investments in the Statements of Consolidated Income. As of December 31, 2000, the Company did not hold debt or equity securities that are classified as "trading." As of December 31, 2001, the Company held equity securities classified as "trading" totaling $1 million. The Company recorded unrealized holding gains on "trading" securities included in gains from investments in the Statements of Consolidated Income of $16 million, $4 million and $5 million during 1999, 2000 and 2001, respectively.

(n) PROJECT DEVELOPMENT COSTS.

Project development costs include costs for professional services, permits and other items that are incurred incidental to a particular project. The Company expenses these costs as incurred until the project is considered probable. After a project is considered probable, capitalizable costs incurred are capitalized to the project. When project operations begin, the Company begins to amortize these costs on a straight-line basis over the life of the facility. As of December 31, 2000 and 2001, the Company had recorded in the Consolidated Balance Sheets project development costs of $7 million and $9 million, respectively.

(o) ENVIRONMENTAL COSTS.

The Company expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Company expenses amounts that relate to an existing condition caused by past operations and that do not have future economic benefit. The Company records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

(p) FOREIGN CURRENCY ADJUSTMENTS.

Local currencies are the functional currency of the Company's 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.

(q) CHANGES IN ACCOUNTING PRINCIPLES AND NEW ACCOUNTING PRONOUNCEMENTS.

Staff Accounting Bulletin No. 101, "Revenue Recognition" (SAB No. 101), was issued by the Securities and Exchange Commission (SEC) staff on December 3, 1999. SAB No. 101 summarizes certain of the SEC staff's views in applying generally accepted accounting principles to revenue recognition in financial statements. The Consolidated Financial Statements reflect the accounting guidance provided in SAB No. 101.

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141 "Business Combinations" (SFAS No. 141) and SFAS No. 142 "Goodwill and Other Intangible Assets" (SFAS No. 142). 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. SFAS No. 142 provides for a nonamortization approach, whereby 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. The Company adopted the provisions of each 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 the Company's historical results of operations or financial position. On January 1, 2002, the Company discontinued amortizing goodwill into its results of operations pursuant to SFAS No. 142. The Company recognized $32 million of goodwill amortization expense in the Statement of Consolidated Income during 2001, excluding a $19 million write-off of a Communications business goodwill balance which was recorded as goodwill amortization expense (see Note 16). The Company is in the process of determining further effects of adoption of SFAS No. 142 on its Consolidated Financial Statements, including the review of goodwill and certain intangibles for impairment. The Company has not completed its review pursuant to SFAS No. 142. However, based on the Company's preliminary review, the Company believes an impairment of its European Energy segment goodwill is reasonably possible. As of December 31, 2001, net goodwill associated with the European Energy segment is $632 million. The Company anticipates finalizing its review of goodwill and certain intangibles for its reporting units during 2002. The Company does not believe impairments of goodwill and certain intangibles, if any, related to the Company's other reporting units will have a material impact on the Company's results of operations or financial position.

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 change in accounting principle in the income statement in the period of adoption. The Company plans to adopt SFAS No. 143 on January 1, 2003, and is in the process of determining the effect of adoption on its Consolidated 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 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 is not expected to materially change the methods used by the Company to measure impairment losses on long-lived assets, but may result in additional future dispositions being reported as discontinued operations than is currently permitted. The Company adopted SFAS No. 144 on January 1, 2002.

See Note 6 for the Company's adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133) on January 1, 2001 and adoption of subsequent cleared guidance.

(3) HISTORICAL RELATED PARTY TRANSACTIONS

The Consolidated Financial Statements include significant transactions between the Company and Reliant Energy involving 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 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 and allocations are not necessarily indicative of what would have been incurred had the Company been a separate entity. Amounts charged and allocated to the Company for these services were $11 million, $34 million and $9 million for 1999, 2000 and 2001, respectively, and are included primarily in operation and maintenance expenses and general and administrative expenses. In addition, during 2001, the Company incurred costs primarily related to corporate support services which were billed to Reliant Energy and its affiliates of $27 million. Some subsidiaries of the Company have entered into office rental agreements with Reliant Energy. During 1999, 2000 and 2001, the Company incurred $1 million, $4 million and $16 million, respectively, of rent expense to Reliant Energy.

Certain of these services and the office space lease arrangements between the Company and Reliant Energy will 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 would have a material effect on the Company's consolidated results of operations, cash flows or financial position. For additional information regarding these services and office space lease arrangements between the Company and Reliant Energy, see Note 4(a).

Below is a detail of accounts and notes receivable (payable) to affiliated companies that are not part of the Company:

	DE
	2000
	(IN
Net accounts receivable - affiliated companies	$ 94
Net short-term notes (payable) receivable - affiliated companies	(1,415
Net long-term notes (payable) receivable - affiliated companies	(648
Total net accounts and notes (payable) receivable - affiliated companies ...	$ (1,969

Net accounts receivable - affiliated companies, representing primarily current month balances of transactions between the Company and Reliant Energy or its subsidiaries, relate primarily to natural gas purchases and sales, interest, charges for services and office space rental. Net short-term notes payable/receivable - affiliated companies represent the accumulation of a variety of cash transfers and operating transactions and specific negotiated financing transactions with Reliant Energy or its subsidiaries and generally bear interest at market-based rates. Net long-term notes payable/receivable - affiliated companies primarily relate to specific negotiated financing transactions with Reliant Energy or its subsidiaries that bear interest at market-based rates. See the discussion below for information regarding the notes payable entered into by the Company with Reliant Energy during 2000 related to the acquisition of Reliant Energy Power Generation Benelux, N.V. (REPGB), a Dutch power generation company, and the acquisition of certain assets and operations held by REMA during May 2000. Net interest expense related to these net borrowings/receivables was $10 million and $172 million during 1999 and 2000, respectively. Net interest income related to these net borrowings/receivables was $12 million during 2001.

Funds for the acquisition of REMA were made available through loans from Reliant Energy. In May 2000, $1.0 billion of these loans were converted to equity and $1.0 billion of these loans were repaid in August 2000 from proceeds received from the sale-leaseback transactions (see Note 5(a)). The loans bore interest at 9.4%.

In connection with funding its purchase of REPGB (see Note 5(b)), a subsidiary of the Company entered into a 560 million Euro-denominated note (approximately $528 million based on the December 31, 2000, exchange rate of 1.0616 Euros per U.S. dollar) with Reliant Energy, which matured on July 1, 2001. At December 31, 2000, the entire Euro 560 million was outstanding on this note. Outstanding indebtedness under the note bore interest at the inter-bank offered rate for Euros (EURIBOR) plus 0.75% per annum. The applicable interest rate was 5.7% at December 31, 2000. In March 2001, the Company paid $236 million of the debt owed to Reliant Energy, along with the accrued interest on the amount. The repayment was made with general corporate funds of the Company, including amounts borrowed under the Company's credit facilities.

In May 2001, Reliant Energy converted or contributed an aggregate of $1.7 billion of the indebtedness owed by the Company to Reliant Energy and its subsidiaries to equity without the issuance of any additional shares of common stock of the Company, pursuant to the master separation agreement by recording an increase to additional paid-in capital of the Company. In addition, the Company used $147 million of the net proceeds of the IPO to repay certain indebtedness owed to Reliant Energy in May 2001.

During 2001, proceeds not initially utilized from the IPO were advanced to a subsidiary of Reliant Energy (the Reliant Energy money fund) on a short-term basis. The Company has reduced its advance to the Reliant Energy money fund following the IPO to fund capital expenditures and to meet its working capital needs. As of December 31, 2001, the Company had outstanding advances to the Reliant Energy money fund of $390 million which is included in accounts and notes receivable in the Company's Consolidated Balance Sheet.

The Company purchases natural gas and transportation services from, supplies natural gas to, and provides marketing and risk management services to affiliates of Reliant Energy that are not part of the Company. Purchases of transportation services and natural gas from Reliant Energy and its subsidiaries were $200 million, $178 million and $188 million in 1999, 2000 and 2001, respectively. During 1999, 2000 and 2001, the sales and services to Reliant Energy and its subsidiaries totaled $330 million, $601 million and $701 million, respectively.

During 2001, REPGB received efficiency and energy payments from BV Nederlands Elektriciteit Administratiekantoor (NEA), an equity investment (see Note 7), 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.

Pursuant to the provisions of the master separation agreement between the Company and Reliant Energy, during 2001 the Company has participated in generation capacity auctions by Reliant Energy's electric utility generation assets (Texas Genco). The Company has also exercised its option included in the master separation agreement to purchase 50% of the capacity, energy and ancillary services of Texas Genco not auctioned in the aforementioned auctions, at the prices established in these auctions. As of December 31, 2001, the Company has minimum commitments to purchase capacity of Texas Genco averaging 6,471 megawatts (MW) per month in 2002 and 775 MW per month in 2003. The Company has no minimum obligations for energy or ancillary services under the master separation agreement. The Company's anticipated payments related to these minimum obligations are $213 million in 2002 and $58 million in 2003. For additional information regarding agreements relating to Texas Genco, see Note 4(b).

During 1999, 2000 and 2001, Reliant Energy or its subsidiaries made equity contributions to the Company of $236 million, $1.4 billion and $1.8 billion, respectively. During 1999, the Company made distributions to a subsidiary of Reliant Energy of $170 million. The contributions received by the Company in 1999 primarily related to cash contributions used to fund (a) the acquisition of a generating facility in Florida (see Note 5(c)) and (b) general operating costs. In addition, during 1999, Arkla Finance Corporation, a subsidiary of the Company, received payment of $170 million on a long-term note receivable from an affiliate. Arkla Finance Corporation distributed the $170 million to its parent company, RERC Corp. The contributions in 2000 primarily related to (a) conversion of $1 billion of the borrowings from Reliant Energy used to fund the acquisition of REMA (see Note 5(a)), (b) the forgiveness of $284 million of debt held by subsidiaries that were transferred from RERC Corp. to the Company (see Note 1) and (c) general operating costs. The contributions in 2001, primarily related to the conversion into equity of debt owed to Reliant Energy and its subsidiaries and some related interest expense totaling $1.7 billion and the contribution of net benefit assets and liabilities, net of deferred income taxes.

(4) RELATED PARTY TRANSACTIONS - AGREEMENTS BETWEEN RELIANT ENERGY AND THE COMPANY

(a) SERVICES AGREEMENTS.

The Company has entered into agreements with Reliant Energy under which Reliant Energy will provide the Company, 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 and payroll, office support services and purchasing and logistics.

These arrangements will continue under a transition services agreement providing for their continuation until December 31, 2004, or, in the case of some corporate support services, until the Distribution. The charges the Company will pay Reliant Energy for these services are generally intended to allow Reliant Energy to recover its fully allocated costs of providing the services, plus out-of-pocket costs and expenses. In each case, the Company will have the right to terminate categories of services at an earlier date. It is not anticipated that termination of these service arrangements will have a material effect on the Company's financial position, results of operations or cash flows.

Pursuant to lease agreements, Reliant Energy will lease the Company office space in its headquarters building and in various other locations in Houston, Texas, for an interim period.

Under a service agreement, the Company provided customer service call center operations, credit and collections and revenue accounting services for Reliant Energy's electric utility division and received and processed payments for the accounts of Reliant Energy's electric utility division and two of Reliant Energy's natural gas distribution divisions. Reliant Energy provided the office space and equipment for the Company to perform these services. The charges Reliant Energy paid the Company for these services were generally intended to allow the Company to recover its fully allocated costs of providing the services, plus out-of-pocket costs and expenses. The service agreement governing these services terminated on December 31, 2001.

(b) AGREEMENTS RELATING TO TEXAS GENCO.

Pursuant to the Texas electric restructuring law, Texas Genco, as the affiliated power generator of Reliant Energy's transmission and distribution utility, is required to sell at auction 15% of the output of its installed generating capacity. This obligation continues until January 1, 2007, unless before that date the Public Utility Commission of Texas (Texas Utility Commission) determines at least 40% of the quantity of electric power consumed in 2000 by residential and small commercial customers in the utility's service area is being served by retail electric providers other than us. The master separation agreement requires Texas Genco to auction all of its capacity that remains subsequent to capacity auctioned pursuant to Texas Utility Commission rules and after certain other deductions (Texas Genco remaining capacity). The Company has the right to purchase 50% (but not less than 50%) of Texas Genco's remaining capacity at the prices to be established in the auction. For a discussion of the Company's purchases of capacity from Texas Genco in 2001, see Note 3. It is expected that Texas Genco will have a total of six auctions in 2002 and 2003.

In connection with the separation of the Company's businesses from those of Reliant Energy, Reliant Energy has agreed either to issue and sell in an initial public offering or to distribute no more than 20% of the common stock of Texas Genco by December 31, 2002. Reliant Energy has granted the Company an option to purchase, subject to the completion of the Distribution, all of the shares of capital stock of Texas Genco that will hold the Texas generating assets of Reliant Energy's electric utility division that will be owned by Reliant Energy after the initial public offering or distribution noted below. The Texas Genco option may be exercised 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 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 Texas Genco's common stock equity. 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. If the disposition to the public of common stock of Texas Genco is by means of a primary or secondary public offering, the public offering may be of as little as 17% of Texas Genco's outstanding common stock, in which case Reliant Energy will have the right to subsequently reduce its interest to a level not less than 80%. The Company has agreed that if it exercises the Texas Genco option and purchases the shares of Texas Genco common stock, the Company will also purchase all notes and other receivables from Texas Genco then held by Reliant Energy, at their principal amount plus accrued interest. Similarly, if Texas Genco holds notes or receivables from Reliant Energy, the Company will assume Reliant Energy's obligations in exchange for a payment to the Company by Reliant Energy of an amount equal to the principal plus accrued interest.

The Company has entered into a support agreement with Reliant Energy, pursuant to which the Company will provide engineering and technical support services and environmental, safety and industrial health services to support operations and maintenance of Texas Genco's facilities. The Company will 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 charged for these services will be designed to allow the Company to recover its 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 the Company's facilities in other regions will be allocated on an installed megawatt basis. The term of this agreement will end on the first to occur of (a) the closing date of the Texas Genco option, (b) Reliant Energy's sale of Texas Genco, or all or substantially all of the assets of Texas Genco, if the Company does not exercise the Texas Genco option, or (c) May 31, 2005, provided the Texas Genco option is not exercised; however, Texas Genco may extend the term of this agreement until December 31, 2005.

When Texas Genco is organized, it will become the beneficiary of the decommissioning trust that has been established to provide funding for decontamination and decommissioning of a nuclear electric generation station in which Reliant Energy owns a 30.8% interest. The master separation agreement provides that Reliant Energy will collect through rates or other authorized charges to its electric utility customers amounts designated for funding the decommissioning trust, and will pay the amounts to Texas Genco. Texas Genco will in turn be required to deposit these amounts received from Reliant Energy into the decommissioning trust. Upon decommissioning of the facility, in the event funds from the trust are inadequate, Reliant Energy 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 Texas Genco'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 Reliant Energy's ratepayers.

(c) OTHER AGREEMENTS.

In connection with the separation of the Company's businesses from those of Reliant Energy, the Company has also entered into other agreements providing for, among other things, mutual indemnities and releases with respect to the Company's 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, the Company and Reliant Energy 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.

The Company has guaranteed, in the event Reliant Energy becomes insolvent, certain non-qualified benefits of Reliant Energy's and its subsidiaries' existing retirees at the Distribution totaling approximately $55 million.

(5) BUSINESS ACQUISITIONS

(a) RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC.

On May 12, 2000, a subsidiary of the Company 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 of the Company 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, the Company made an $8 million payment to the prior owner for post-closing adjustments which resulted in an adjustment to purchase price. The Company accounted for the acquisition as a purchase with assets and liabilities of REMA reflected at their estimated fair values. The

Company's 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 which 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 $5 million was recorded as goodwill and historically was amortized over 35 years.

The Company 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 Reliant Energy. 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	5	(146)
Other intangibles	196	33
Other assets	3	(5)
Current liabilities	(50)	(13)
Other liabilities	(39)	(15)
Total	$ 2,098	$ 454

Adjustments to property, plant and equipment, other intangibles which includes 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, the Company entered into separate sale-leaseback transactions with each of three owner-lessors covering the Company's 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, the Company leases an interest in each facility from each owner-lessor under a leveraged facility lease agreement. As consideration for the sale of the Company's interest in the facilities, the Company received $1.0 billion in cash. The Company used the $1.0 billion of sale proceeds to repay intercompany indebtedness owed by the Company to Reliant Energy.

The Company's results of operations include the results of REMA only for the period beginning May 12, 2000. The following table presents selected actual financial information and unaudited pro forma information for 1999 and 2000, as if the acquisition had occurred on November 24, 1999 and January 1, 2000, as applicable. Pro forma information for operations prior to November 24, 1999 would not be meaningful since historical financial results of the business and the revenue generating activities underlying that period are substantially different from the wholesale generation activities that REMA has been engaged in after November 24, 1999. Pro forma amounts also give effect to the sale and leaseback of interests in three of the REMA generating plants, which were consummated in August 2000.

	YEAR ENDED DECEMBER 31,		
	1999		200
	ACTUAL	PRO FORMA	ACTUAL
	(IN MILLIONS)		
Revenues	$ 6,539	$ 6,569	$ 18,722
Income after tax and before extraordinary item ...	24	14	203
Net income	24	14	210

These unaudited pro forma results, based on assumptions deemed appropriate by the Company's 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 November 24, 1999 and January 1, 2000, as applicable. Purchase-related adjustments to the results of operations include the effects on depreciation and amortization, interest expense and income taxes.

(b) RELIANT ENERGY POWER GENERATION BENELUX N.V.

Effective October 7, 1999, the Company 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 the Company consisted of $833 million in cash. On March 1, 2000, under the terms of the acquisition agreement, the Company funded the remaining purchase obligation for $982 million. A portion ($596 million) of this obligation was financed with a three-year term loan facility obtained in the first quarter of 2000 (see Note 8(a)).

For the two month period ended November 30, 1999, the Company accounted for its interest in REPGB using the equity method rather than the consolidation method. This resulted in income of equity investment of unconsolidated subsidiaries of $22 million for the year ended December 31, 1999.

The Company recorded the REPGB acquisition under the purchase method of accounting, with assets and liabilities of REPGB reflected at their estimated fair values. As outlined in the table below, the Company's fair value adjustments related to the acquisition of REPGB primarily included increases in property, plant and equipment, long-term debt, severance liabilities, post-employment benefit liabilities and deferred foreign taxes. Additionally, a $19 million receivable was recorded in connection with the acquisition as the selling shareholders agreed to reimburse REPGB for some obligations incurred prior to the purchase of REPGB. Adjustments to property, plant and equipment are based on valuation reports prepared by independent appraisers and consultants. The excess of the purchase price over the fair value of net assets acquired of $877 million was recorded as goodwill and was historically amortized on a straight-line basis over 30 years. The Company finalized these fair value adjustments in September 2000. The Company finalized a severance plan (REPGB Plan) in connection with the REPGB acquisition in September 2000 (commitment date) and in accordance with EITF 95-3 "Recognition of Liabilities in Connection with a Purchase Business Combination," recorded this liability of $19 million in the third quarter of 2000. During 2001, the Company utilized $8 million of the reserve for the REPGB Plan. As of December 31, 2001, the remaining severance liability is $11 million. The majority of the $11 million of remaining severance liability will be disbursed in accordance with the terms and conditions outlined by a collective labor bargaining agreement regarding employees near retirement age (Social Plan) in accordance with applicable Dutch labor law. The Social Plan, which by formula defines termination benefits, prescribes a payout period for up to 5 years for an employee subsequent to termination date. In the fourth quarter of 2001, the Dutch taxing authority finalized REPGB's tax basis of property, plant and equipment as of October 1999. As a result, the Company recorded an adjustment to decrease goodwill and accumulated deferred tax liability by $5 million in the fourth quarter of 2001. As of December 31, 2001, the tax basis of other certain assets and liabilities has not been finalized.

In connection with the acquisition of REPGB, the Company developed a comprehensive business process reengineering and employee severance plan intended to make REPGB competitive in the deregulated Dutch electricity market that began January 1, 2001. The REPGB Plan's initial conceptual formulation was initiated prior to the acquisition of REPGB in October 1999. The finalization of the REPGB Plan was approved and completed in September 2000. The Company identified 195 employees who were involuntarily terminated in REPGB's following functional areas: plant operations and maintenance, procurement, inventory, general and administrative, legal, finance and support. The Company has notified all employees identified under the severance component of the REPGB Plan that they are subject to involuntary termination and the majority of terminations occurred during 2001. The termination benefits under the REPGB Plan are governed by REPGB's Social Plan, a collective bargaining agreement between REPGB and its various representative labor unions signed in 1998. The Social Plan provides defined benefits for involuntarily severed employees depending upon age, tenure and other factors, and was agreed to by the management of REPGB as a result of the anticipated deregulation of the Dutch electricity market. The Social Plan is still in force and binding on the current management of the Company and REPGB. The Company is still executing the REPGB Plan as of the date of these Consolidated Financial Statements.

The net purchase price of REPGB 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	$ 244	$ 34
Property, plant and equipment	1,899	719
Goodwill	877	877
Current liabilities	(336)	--
Deferred taxes	(76)	(76)
Long-term debt	(422)	(87)
Other long-term liabilities	(244)	(35)
Total	$ 1,942	$ 1,432

The following table presents selected actual financial information for 1999 and unaudited pro forma information for 1999, as if the acquisition of REPGB had occurred on January 1, 1999. The pro forma results are based on assumptions deemed appropriate by the Company's management, have been prepared for informational purposes only and are not necessarily indicative of the consolidated results that would have resulted if the acquisition of REPGB had occurred on January 1, 1999. Purchase related adjustments to results of operations include amortization of goodwill, interest expense and the effects on depreciation and amortization of the assessed fair value of some of REPGB's net assets and liabilities.

	1999	
	ACTUAL	PRO FORMA
	(IN MILLIONS)	
Revenues	$ 6,539	$ 7,116
Net income (loss)	24	(3)

(c) FLORIDA GENERATION PLANT PURCHASE.

On October 6, 1999, the Company purchased a steam turbine generation plant (Indian River) with a net generating capacity of 619 MW from a Florida municipality (Municipality) for a net purchase price of $188 million. Indian River, located near Titusville, Florida, consists of three conventional steam generation units fueled by both oil and natural gas. Under the Company's ownership, the units will sell up to 578 MW of power generation from Indian River to the Municipality through a power purchase agreement that was originally scheduled to expire in September 2003, but has been extended through September 2007. During the option period, the Municipality has the right to purchase up to 500 MW for the first two years of the option period and 300 MW for the final two years. Any excess power generated by the plant may be sold to other utilities and rural electric cooperatives within the state and other entities within the Florida wholesale market. The Company recorded the acquisition under the purchase method of accounting. The purchase price has been allocated to assets acquired and liabilities assumed based on their estimated fair market values at the date of acquisition. The Company's fair value adjustments related to the acquisition of Indian River primarily included increases in property, plant and equipment, specific intangibles related to water rights and permits, major maintenance reserves and related deferred taxes. The specific intangibles of $112 million are being amortized over their contractual lives of 35 years. The Company finalized these fair value adjustments during September 2000. There were no material adjustments made to the purchase allocation subsequent to December 31, 1999.

Net purchase price of Indian River was allocated as follows (in millions):

Current assets	$ 15
Property, plant and equipment	93
Goodwill	2
Other intangibles	112
Major maintenance reserve	(3)
Other long-term liabilities	(31)
Total	$ 188

The Company's results of operations include Indian River's results of operations only for the period beginning with the October 6, 1999 acquisition date. Pro forma information has not been presented for Indian River for 1999. Pro forma information would not be meaningful since historical financial results of the business and the revenue generating activities underlying that period as described below are substantially different from the wholesale generation activities that Indian River has been engaged in after October 6, 1999. Prior to the Company's acquisition, the acquired Indian River generation operations were fully integrated with, and its results of operations were consolidated into, the Municipality's vertically integrated utility operations. In addition, prior to the Company's acquisition, the electric output of these facilities was sold based on rates set by regulatory authorities and are not indicative of these assets' future operating results as a wholesale electricity provider.

(6) DERIVATIVE INSTRUMENTS

Effective January 1, 2001, the Company 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 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 (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.

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 the Company's Consolidated Balance Sheet. During the year ended December 31, 2001, $249 million of the initial after-tax transition adjustment recognized in other comprehensive income was recognized in net income.

The application of SFAS No. 133 is still evolving as the FASB clears issues submitted to the Derivatives Implementation Group for consideration. During the second quarter of 2001, an issue that applies exclusively to the electric industry and allows the normal purchases and normal sales exception for option-type contracts if certain criteria are met was approved by the FASB with an effective date of July 1, 2001. The adoption of this cleared guidance had no impact on the Company's results of operations. Certain criteria of this previously approved guidance were revised in October and December 2001 and will become effective on April 1, 2002. The Company is currently in the process of determining the effect of adoption of the revised guidance.

During the third quarter of 2001, the FASB cleared an issue related to application of the normal purchases and normal sales exception to contracts that combine forward and purchased option contracts. The effective date of this guidance is April 1, 2002, and the Company is currently assessing the impact of this cleared issue and does not believe it will have a material impact on the Company's consolidated financial statements.

The Company is exposed to various market risks. These risks arise from transactions entered into in the normal course of business and are inherent in the Company's consolidated financial statements. The Company utilizes 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 its operating results and cash flows. The

Company utilizes cross-currency swaps, forward contracts and options to hedge its net investments in and cash flows of its foreign subsidiaries, interest rate swaps to mitigate the impact of changes in interest rates and other financial instruments to manage various other market risks.

Trading and marketing operations often involve risk associated with managing energy commodities and 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. The Company routinely enters into Energy Derivatives to hedge sale commitments, fuel requirements and inventories of natural gas, coal, electricity, crude oil and products, emission allowances and other commodities and to minimize the risk of market fluctuations in its trading, marketing, power origination and risk management services operations.

Energy Derivatives primarily used by the Company 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, POWER ORIGINATION AND PRICE RISK MANAGEMENT SERVICES ACTIVITIES.

The Company offers energy price risk management services primarily related to natural gas, electric power and other energy related commodities. These activities also include the establishing of open positions in the energy markets, primarily on a short-term basis, and transactions intended to optimize the Company's power generation portfolio, but which do not qualify for hedge accounting. The Company provides these services by utilizing a variety of derivative instruments (Trading Energy Derivatives).

The Company applies mark-to-market accounting for all of its energy trading, marketing, power origination and price risk management services operations in North America and Europe, as well as to retail contracted sales to large commercial, industrial and institutional customers. Accordingly, these Trading Energy Derivatives 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.

	FAIR VALUE	
	ASSETS	LIABILITIES
	(IN MILLIONS)	
DECEMBER 31, 2000		
Natural gas	$ 3,823	$ 3,818
Electricity	974	946
Oil and other	39	39
	$ 4,836	$ 4,803
DECEMBER 31, 2001		
Natural gas	$ 1,389	$ 1,303
Electricity	648	517
Oil and other	21	20
	$ 2,058	$ 1,840

All of the fair values shown in the table above at December 31, 2000 and

2001 have been recognized in income. The fair values as of December 31, 2000 and 2001, are estimated by using quoted prices where available, other valuation techniques when market data is not available, for example in illiquid markets, and other factors such as the time value and volatility factor for the underlying commitment. The Company's 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 the position.

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, power origination, marketing 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 estimates 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.

The weighted-average term of the trading portfolio, based on volumes, is less than one year. The maximum term of the trading portfolio is 17 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 the Company's 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, the Company 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.

The Company applies hedge accounting for its 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 120% for hedge designation. If and when correlation ceases to exist at an acceptable level, hedge accounting ceases and mark-to-market accounting is applied. During 2001, the amount of hedge ineffectiveness recognized in earnings from derivatives that are designated and qualify as Cash Flow Hedges was a gain of $8 million. 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, the Company realizes in net income the deferred gains and losses recognized in accumulated other comprehensive loss. During 2001, there were no deferred gains or 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. Once the anticipated transaction occurs, the accumulated deferred gain or loss recognized in accumulated other comprehensive income (loss) is reclassified and included in the Company's Statements of Consolidated Income 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. Cash flows resulting from these transactions in Non-trading Energy Derivatives are included in the Statements of Consolidated Cash Flows in the same category as the item being hedged. As of December 31, 2001, the Company's current non-trading-derivative assets and liabilities and corresponding amounts in accumulated other comprehensive loss were expected to be reclassified into net income during the next twelve months.

The maximum length of time the Company is hedging its exposure to the variability in future cash flows for forecasted transactions excluding the payment of variable interest on existing financial instruments is eleven years.

The maximum length of time the Company is hedging its exposure to the payment of variable interest rates is four years.

During the year ended December 31, 2001, the Company entered into interest-rate swaps in order to adjust the interest rate on $200 million of its floating rate debt. In addition, as of December 31, 2001, European Energy has entered into transactions to purchase $271 million 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. The Company has substantially hedged the foreign currency exposure of its net investment in its European subsidiaries through a combination of Euro-denominated borrowings, foreign currency swaps and foreign currency forward contracts to reduce the Company's exposure to changes in foreign currency rates. During the normal course of business, the Company reviews its currency hedging strategies and determines the hedging approach deemed appropriate based upon the circumstances of each situation.

The Company records 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 the Company's net investment in its European subsidiaries. These amounts generally offset amounts recorded in stockholders' equity as adjustments resulting from translation of the hedged investment into U.S. dollars. During 2001, the derivative and non-derivative instruments designated as hedging the net investment in the Company's European subsidiaries resulted in a gain of $31 million, which is 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. The legislation became effective in all material respects on January 1, 2001. 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. These contracts are derivatives pursuant to SFAS No. 133. As of December 31, 2001, the Company had recognized $369 million in short-term and long-term non-trading derivative liabilities for REPGB's portion of these stranded costs contracts. Future changes in the valuation of these stranded cost import contracts which remain an obligation of REPGB will be recorded as adjustments to the Company's Statement of Consolidated Income. The valuation of the contracts could be affected by, among other things, changes in the price of electric power, coal, low sulfur fuel oil and the value of the United States dollar and British pound relative to the Euro. For additional information regarding REPGB's stranded costs and the related indemnification by former shareholders of these stranded costs during 2001, see Note 13(f).

During 2001, the Company entered into two structured transactions which were recorded on the 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 or 2003. The change in fair value of these derivative assets and liabilities must be recorded in the statement of income for each reporting period. During 2001, $117 million of net non-trading derivative liabilities were settled related to these transactions, and a $1 million pre-tax unrealized gain was recognized. As of December 31, 2001, the Company has recognized $221 million of non-trading derivative assets and $103 million of non-trading derivative liabilities related to these transactions.

(c) CREDIT RISKS.

In addition to the risk associated with price movements, credit risk is inherent in the Company's risk management activities and hedging activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. The Company has off-balance sheet risk to the extent that the counterparties to these transactions may fail to perform as required by the terms of each contract. The Company enters into derivative instruments primarily with counterparties having at least a minimum investment grade credit rating (i.e., a minimum credit rating for such entity's senior unsecured debt of BBB- for Standard & Poor's and Fitch or Baa3 for Moody's). In addition, the Company seeks to enter into netting agreements that permit us to offset receivables and payables with a given counterparty. The Company also attempts to enter into agreements that enable the Company to obtain collateral from a counterparty or to terminate upon the occurrence of credit-related

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events. For long-term arrangements, the Company periodically reviews the financial condition of these counterparties in addition to monitoring the effectiveness of these financial contracts in achieving the Company's objectives. If the counterparties to these arrangements fail to perform, the Company would seek to compel performance at law or otherwise obtain compensatory damages. The Company might be forced to acquire alternative hedging arrangements or be required to replace the underlying commitment at then-current market prices. In this event, the Company 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 13(i). For information regarding the net provision recorded in 2001 related to energy sales to Enron, see Note 17.

The following tables show the composition of the trading and marketing assets of the Company as of December 31, 2000 and 2001 and the non-trading derivative assets as of December 31, 2001.

	DECEMBER 31, 2000		D
TRADING AND MARKETING ASSETS	INVESTMENT GRADE (1)(2)	TOTAL	INVES GRADE
		(IN MILLIONS)	
Energy marketers	$ 2,291	$ 2,481	$
Financial institutions	1,099	1,228	
Gas and electric utilities	472	542	
Oil and gas producers	474	566	
Commercial, industrial and institutional customers	73	85	
Total	$ 4,409	4,902	$
Credit and other reserves		(66)	
Trading and marketing assets		$ 4,836	

	DECEMBER 31, 2001	
NON-TRADING DERIVATIVE ASSETS	INVESTMENT GRADE (1)(2)	TOTAL
	(IN MILLIONS)	
Energy marketers	$ 371	$ 408
Financial institutions	76	76
Gas and electric utilities	89	90
Oil and gas producers	8	76
Commercial, industrial and institutional customers	7	8
Others	5	5
Total	$ 556	663
Credit and other reserves		(16)
Non-trading derivative assets		$ 647

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(1) "Investment Grade" is primarily determined using publicly available credit ratings along with the consideration of credit support (such as parent company guarantees) and collateral, which encompass cash and standby letters of credit.

(2) For unrated counterparties, the Company performs financial statement analysis, considering contractual rights and restrictions, and collateral, to create a synthetic credit rating.

(d) TRADING AND NON-TRADING - GENERAL POLICY.

The Company has established a Risk Oversight Committee comprised of corporate and business segment officers that oversees all commodity price, foreign currency and credit risk activities, including the Company's trading, marketing, power origination, risk management services and hedging activities. The committee's duties are to approve the Company's commodity risk policies, allocate risk capital within limits established by the Company's board of directors, approve trading of new products and commodities, monitor risk positions and monitor compliance with the Company's risk management policies and procedures and trading limits established by the Company's board of directors.

The Company's 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.

(7) EQUITY INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

The Company has a 50% interest in a 490 MW electric generation plant in Boulder City, Nevada. The plant became operational in May 2000. The Company has a 50% partnership interest in a 100 MW cogeneration plant in Orange, Texas which began commercial operations in December 1999. In addition, the Company, through REPGB, has a 22.5% interest in NEA, which was formerly the coordinating body for the Dutch electricity generating sector. For information regarding the Company's investment in NEA and financial impacts, see Note 13(f). See Note 5(b) for a description of 1999 equity accounting related to REPGB during 1999.

The Company's equity investments in unconsolidated subsidiaries are as follows:

	AS OF DECEMBER 31, 2000	AS OF DECEMBER 31, 2001
	(IN MILLIONS)	
Nevada generation plant	$ 77	$ 57
Texas cogeneration plant	32	31
NEA	--	299
Equity investments in unconsolidated subsidiaries	$ 109	$ 387

The Company's income (loss) from equity investments of unconsolidated subsidiaries is as follow:

	YEAR ENDED DECEMBER 31, 1999	2000	2001

	(IN MILLIONS)		
Nevada generation plant	$ (1)	$ 42	$
Texas cogeneration plant	--	1	
NEA	--	--	
REPGB	22	--	
Income from equity investments in unconsolidated subsidiaries	$ 21	$ 43	$

During 1999, there were no distributions from these investments. During 2000 and 2001, $18 million and $27 million, respectively, were the net distributions from these investments.

(8) SHORT-TERM BORROWINGS AND LONG-TERM DEBT TO THIRD PARTIES

The following table presents the components of short-term borrowings and long-term debt to third parties as of December 31, 2000 and 2001.

	2000		
	LONG-TERM	CURRENT (1)	LONG-TER
		(IN MILLIONS)	
Total short-term borrowings (2)	$ --	$ 126	$
Long-term debt:			
Reliant Energy Power Generation, Inc. notes payable	260	--	
European Energy (2)(3)	631	1	
Debentures unamortized premium (3)	1	--	
Total long-term borrowings	892	1	
Total borrowings	$ 892	$ 127	$

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(1) Includes amounts due within one year of the date noted.

(2) Borrowings were primarily denominated in Euros and the assumed exchange rate was 1.0616 Euros per U.S. dollar and 1.1242 Euros per U.S. dollar at December 31, 2000 and 2001, respectively, except for $92 million included in short-term borrowings at December 31, 2001.

(3) REPGB debt was adjusted to fair market value as of the acquisition date. The unamortized premium is related to these fair value adjustments and was amortized over the respective remaining term of the related long-term debt.

(a) SHORT-TERM BORROWINGS.

As of December 31, 2001, the Company had $5.6 billion in committed credit facilities, including facilities of subsidiaries of REPG and REPGB, of which $4.1 billion remained unused. These facilities expire as follows: $1.1 billion in 2002, $3.3 billion in 2003 and $800 million in 2004. These expirations exclude $383 million of facilities that will be converted to long-term loans in 2002, as further discussed below. 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.

As of December 31, 2000, the Company had $1.8 billion of committed credit facilities in effect, which included facilities of subsidiaries of REPG and REPGB. As of December 31, 2000, $470 million was unused. As of December 31, 2000, letters of credit outstanding under two of the facilities aggregated $384 million. As of December 31, 2000, borrowings of $825 million were outstanding under these facilities that were classified as long-term debt, based upon the availability of committed credit facilities with expiration dates exceeding one year and management's intention to maintain these amounts in excess of one year.

In 2001, the Company entered into two syndicated revolving credit facilities with financial institutions, which provide for $800 million each or an aggregate of $1.6 billion in committed credit. As of December 31, 2001, letters of credit outstanding under these two facilities aggregated $51 million. At December 31, 2001, there were no outstanding borrowings under these facilities. One of these facilities expires on August 22, 2002, with any outstanding loans on such date being converted at the Company's option to term loans with a maturity of one year from the date of conversion, provided the Company meets certain conditions. The other facility has a maturity date of August 22, 2004. Interest rates on the borrowings are based on the London inter-bank offered rate (LIBOR) plus a margin, a base rate or a rate determined through a bidding process. The credit facilities are subject to facility and usage fees that are calculated based on the amount of the facility commitments and on the amounts outstanding under the facilities, respectively.

During the fourth quarter of 2001 the Company also entered into a term loan facility that provided for $2.2 billion in funding to finance the purchase of Orion Power Holdings, Inc. (Orion Power). Interest rates on the borrowings are based on LIBOR plus a margin or a base rate. The facility was subject to commitment fees that were calculated based on the amount of the unused facility. In January 2002, the facility was increased to $2.9 billion. This facility was funded on February 19, 2002 for $2.9 billion. This term loan must be repaid within one year from the date on which it was funded. For discussion of the acquisition of Orion Power, see Note 19. At December 31, 2001, there were no outstanding borrowings under this facility.

The three facilities, as discussed above, contain various business and financial covenants requiring us to, among other things, maintain a ratio of net balance sheet debt to the sum of net balance sheet debt, subordinated affiliate balance sheet debt and stockholders' equity not to exceed 0.60 to 1.00. These covenants are not anticipated to materially restrict us from borrowing funds or, in the case of the revolvers, obtaining letters of credit under these facilities.

In July 2000, REPGB entered into two credit facilities which include (a) a 364-day revolving credit facility for Euro 250 million ($222 million assuming the December 31, 2001 exchange rate of 1.1242 Euros per U.S. dollar), which was 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 13(d)). Under the two facilities, there is no recourse to any affiliate of the Company other than REPGB. The 364-day revolving credit facility for Euro 250 million bears interest at EURIBOR plus a margin. A commitment fee of 0.175% per annum was payable on the average daily unused portion of the

Euro 250 million facility. At December 31, 2000 and 2001, borrowings of $126 million and $155 million, respectively, were outstanding under the REPGB facility. The weighted-average interest rate on these short-term borrowings as of December 31, 2000 and 2001 was 5.65% and 4.18%, respectively. Under the letter of credit facility, a fee is payable by the Company on each letter of credit that is outstanding based on REPGB's credit rating. A commitment fee of 0.25% per annum is payable on the average daily unused portion of the $420 million letter of credit facility. At December 31, 2000 and 2001, letters of credit of $274 million and $272 million were outstanding under this facility. These facilities contain covenants and requirements that must be met by REPGB to borrow funds or obtain letters of credit, 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 the Company from borrowing funds or obtaining letters of credit, as applicable, under these facilities.

As of December 31, 2001, the Company, through REPGB, has $50 million (assuming the exchange rate of 1.1242 Euros per U.S. dollar at December 31, 2001) 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.

(b) LONG-TERM DEBT.

In February 2000, a subsidiary of the Company established a Euro 600 million term loan facility ($534 million assuming the December 31, 2001 exchange rate of 1.1242 Euros per U.S. dollar) that terminates in March 2003. The facility bears interest at EURIBOR plus a margin. At December 31, 2000 and 2001, $565 million and $534 million (assuming the exchange rate of 1.0616 and 1.1242 Euros per U.S. dollar, respectively) under this facility was outstanding at an interest rate of 5.873% and 4.6396%, respectively. This facility is secured by a pledge of the shares of REPGB's indirect holding company. This facility contains covenants that require the Company's subsidiary 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.

On December 15, 1999, a special purpose project subsidiary of REPG 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 is (a) $92 million in equity bridge loans for the purpose of paying or reimbursing project costs, (b) $369 million in non-recourse loans to finance the construction of the project and (c) $14 million in revolving loans for general working capital purposes. As of December 31, 2000 and 2001, the project subsidiary had drawn $260 million and $389 million in equity bridge and construction loans, respectively. As of December 31, 2001, $92 million related to the equity bridge loan is classified in short-term borrowings and $2 million is classified in current portion of long-term debt. The loans bear interest at either (a) at the borrower's option (i) a base rate or (ii) a Euro dollar rate plus a margin, or (b) a fixed rate of 9.547%. The applicable interest rate was 7.9466% and 5.6565% at December 31, 2000 and 2001, respectively. Notes issued under the facility are pre-payable at any time and are due at various expiration dates beginning November 2002 through August 2024. Amounts drawn under the construction loan facility is convertible into term loans at project completion. Under the credit agreement, the equity bridge loans will be repaid no later than November 2002 and the construction loans will be converted into term loans at completion. Final maturities of the term loans range from 15 to 22 years following the plant's commercial operation. Commercial operation is expected no later than November 2002. Advances under the working capital facility mature five years after the plant begins commercial operations. A commitment fee of 0.35% per annum is payable on the average daily unused portions of the equity and construction loan commitments and working capital commitment once available. The Company incurred $7 million in debt financing costs in 1999 associated with this project financing. These costs are being amortized over the term of the facility. Obligations under the construction and term loans and revolving credit facility are secured by a first priority security interest in the assets and future revenues of the plant and a pledge of the ownership interest in the plant. Although the loans are non-recourse in nature, an indemnification agreement exists that may require REPG, in some circumstances, to reimburse the lenders for amounts up to the total contract price for the construction of the plant (approximately $331 million). This indemnity agreement terminates upon achievement of certain performance standards under the construction agreement. The $475 million credit facility contains covenants and requirements that must be met by the project subsidiary to borrow funds. These covenants are not anticipated to materially restrict the borrowing of funds under the facility.

Outstanding long-term indebtedness of REPGB of $67 million and $61 million at December 31, 2000 and 2001, respectively, consisted primarily of loans maturing through 2006. Some covenants under these loans restrict some

actions by REPGB. The weighted-average interest rate of these loans at December 31, 2000 and 2001 was 7.93% and 7.35%, respectively. 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.

As of December 31, 2001, maturities of borrowings classified as long-term debt were $24 million in 2002, $539 million in 2003, $42 million in 2004, $12 million in 2005, $12 million in 2006 and $263 million in 2007 and beyond.

(c) OFF-BALANCE SHEET FINANCINGS.

For information regarding off-balance sheet financings and REMA sale-leaseback transactions, see Notes 13(c) and 13(h).

(9) 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 between Reliant Energy and Reliant Resources, the Company used $147 million of the net proceeds to repay certain indebtedness owed to Reliant Energy. The Company used the remainder of the net proceeds of the IPO for repayment of third party borrowings, capital expenditures, repurchases of common stock and to increase the Company's working capital.

(b) TREASURY STOCK PURCHASES.

In July 2001, the Board of Directors authorized the Company to purchase up to one million shares of its common stock in anticipation of funding benefit plan obligations expected to be funded prior to the Distribution. On September 18, 2001, the Board of Directors authorized the Company to purchase up to 10 million additional shares of common stock through February 2003, and on December 6, 2001, the Board of Directors authorized the Company to purchase up to an additional 10 million shares of its common stock through June 2003. During 2001, the Company purchased 11 million shares of its 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 Reliant Energy's percentage ownership in the Company from approximately 80% to approximately 83%. Reliant Energy recorded the acquisition of treasury shares under the purchase method of accounting and pushed-down the effect to the Company. As such, the Company recorded a decrease in property, plant and equipment related to REPGB and additional paid-in capital of $43 million.

(10) EARNINGS PER SHARE

The following table presents Reliant Resources' basic and diluted earnings per share (EPS) calculation for the year ended December 31, 2001 (shares in thousands). There were no dilutive reconciling items to net income.

Diluted Weighted Average Shares Calculation:	
Weighted average shares outstanding	277,144
Plus: Incremental shares from assumed conversions:	
Stock options	2
Restricted stock	244
Employee stock purchase plan	83
Weighted average shares assuming dilution	277,473
Basic and Diluted EPS:	
Income before cumulative effect of accounting change	$ 2.00
Cumulative effect of accounting change, net of tax	0.01
Net income	$ 2.01

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.

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 effect a 240,000 to 1 stock split of Reliant Resources' common stock on January 5, 2001.

(11) STOCK-BASED INCENTIVE COMPENSATION PLANS AND RETIREMENT PLANS

(a) STOCK-BASED INCENTIVE COMPENSATION PLANS.

Subsequent to the IPO, the Company's eligible employees and non-employee directors began participating in Reliant Resources' Long-Term Incentive Plan (LTIP) that provides for the issuance of stock-based incentives, including performance-based shares or units, restricted shares, stock options and stock appreciation rights, to key employees of the Company, including officers.

Prior to the IPO, the Company's eligible employees participated in Reliant Energy's Long-Term Incentive Compensation Plan (Reliant Energy LICP) and other incentive compensation plans that provide for the issuance of stock-based incentives, including performance-based shares, restricted shares, stock options and stock appreciation rights, to key employees of the Company, including officers. No stock appreciation rights have ever been issued under the Reliant Energy LICP. Stock-based incentive grants and expense information presented herein represents the Company's portion of the overall plans.

Performance-based shares and restricted shares have been granted to employees without cost to the participants under the Reliant Energy LICP and the LTIP. 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 six-year period. Upon vesting, the shares are issued to the plans' participants. During 1999, 2000 and 2001, the Company recorded compensation expense of $0.9 million, $6.7 million and $8.2 million, respectively, related to performance-based shares and restricted share grants. The following table summarizes performance-based shares and restricted share grant activity related to the Company for the years 1999 through 2001:

	RELIANT ENERGY		RELIANT
	NUMBER OF PERFORMANCE-BASED SHARES	NUMBER OF RESTRICTED SHARES	NUMBER OF PERFORMANCE-BASED SHARES
Outstanding at December 31, 1998	135,301	8,626	
Granted	115,501	87,429	
Released to participants	(14,764)	(2,869)	

Outstanding at December 31, 1999	236,038	93,186	
Granted	106,125	143,727	
Released to participants	(16,225)	(3,473)	
Canceled	(40,610)	--	
Outstanding at December 31, 2000	285,328	233,440	
Shares relating to transferred employees	224,325	72,390	
Granted	--	--	693,135
Released to participants	(57,735)	(99,561)	--
Canceled	(26,843)	(330)	--
Outstanding at December 31, 2001	425,075	205,939	693,135
Weighted average fair value of performance and restricted stock granted for 1999	$ 26.16	$ 26.97	
Weighted average fair value of performance and restricted stock granted for 2000	$ 24.18	$ 30.87	
Weighted average fair value of performance and restricted stock granted for 2001			$ 22.50

Assuming the Distribution occurs during 2002, as of the Distribution, Reliant Energy's compensation committee will convert outstanding performance shares under the Reliant Energy LICP for the performance cycle ending December 31, 2002 to a number of time-based restricted shares of Reliant Energy's common stock equal to the number of performance-based shares that would have vested if the performance objectives for the performance cycle were achieved at the maximum level. These time-based restricted shares will vest if the participant holding the shares remains employed with Reliant Energy or with the Company through December 31, 2002. On the date of the Distribution, holders of these time-based restricted shares will receive shares of the Company's common stock in the same manner as other holders of Reliant Energy common stock, but these shares of the Company's common stock will be subject to the same time-based vesting schedule, as well as to the terms and conditions of the plan under which the original performance-based shares were granted. Thus, following the Distribution, employees who held performance-based shares under Reliant Energy's LICP for the performance cycle ending December 31, 2002 will hold time-based restricted shares of Reliant Energy's common stock and time-based restricted shares of the Company's common stock which will vest following continuous employment through December 31, 2002.

In 2001, some employees of Reliant Energy, primarily corporate support and executive officers, transferred to the Company. These employees held Reliant Energy performance-based shares and restricted shares of approximately 224,000 and approximately 72,000, respectively.

Under both Reliant Energy's and the Company's plans, stock options generally become exercisable in one-third increments on each of the first through third anniversaries of the grant date. The exercise price is based on the average of the high and low sales price of the applicable common stock on the New York Stock Exchange on the grant date. The Company applies Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB No. 25), and related interpretations in accounting for its stock option plans. Accordingly, no compensation expense has been recognized for these fixed stock options. The following table summarizes stock option activity related to the Company for the years 1999 through 2001:

	RELIANT ENERGY	
	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at December 31, 1998	681,109	$ 25.11
Options granted	1,311,657	27.06
Options exercised	(21,836)	14.47
Options canceled	(145,345)	
Outstanding at December 31, 1999	1,825,585	26.47
Options granted	2,100,239	23.33
Options exercised	(700,863)	21.67
Options canceled	(128,706)	
Outstanding at December 31, 2000	3,096,255	24.71
Options relating to transferred employees	3,714,223	24.31
Options granted	116,492	41.62
Options exercised	(817,563)	24.06
Options canceled	(223,288)	
Outstanding at December 31, 2001	5,886,119	24.81
Options exercisable at December 31, 1999	256,958	24.92
Options exercisable at December 31, 2000	458,659	26.64
Options exercisable at December 31, 2001	2,683,755	25.62

Exercise prices for Reliant Energy stock options outstanding and held by Company employees ranged from $17.75 to $50.00. Exercise prices for Reliant Resources stock options outstanding held by Company employees ranged from $15.65 to $34.03. The following tables provide information with respect to outstanding Reliant Energy and Reliant Resources stock options held by the Company's employees at December 31, 2001:

	RELIANT ENERGY		
	OPTIONS OUTSTANDING	AVERAGE EXERCISE PRICE	REMAINING AVERAGE CONTRACTUAL LIFE (YEARS)
Ranges of Exercise Prices			
Exercisable at:			
$17.75-$26.00	3,586,020	$ 21.46	7.7

$26.01-$50.00	2,300,099	30.03	7.6
Total	5,886,119	24.81	7.7

	RELIANT RESOURCES		
	OPTIONS OUTSTANDING	AVERAGE EXERCISE PRICE	REMAINING AVERAGE CONTRACTUAL LIFE (YEARS)
Ranges of Exercise Prices Exercisable at:			
$15.65 - $23.50	95,436	$ 20.62	9.7
$23.51 - $34.03	8,485,166	29.97	9.2
Total	8,580,602	29.86	9.2

The following table provides information with respect to exercisable Reliant Energy stock options held by the Company's employees at December 31, 2001:

	RELIANT ENERGY	
	OPTIONS EXERCISABLE	AVERAGE EXERCISE PRICE
Ranges of Exercise Prices Exercisable at:		
$17.75 - $26.00	1,413,013	$ 22.69
$26.01 - $47.22	1,270,742	28.88
Total	2,683,755	25.62

At December 31, 2001, there were 6,500 exercisable Reliant Resources stock options with an exercise price of $30.00 and a remaining contractual life of 9.2 years.

In accordance with SFAS No. 123, "Accounting for Stock-Based Compensation," the Company applies the guidance contained in APB No. 25 and discloses the required pro forma effect on net income of the fair value based method of accounting for stock compensation. The weighted average fair values at date of grant for Reliant Energy options granted during 1999, 2000 and 2001 were $3.13, $5.07 and $9.25, respectively. The weighted average fair value at date of grant for Reliant Resources options granted during 2001 was $13.35. The fair values were estimated using the Black-Scholes option valuation model with the following weighted-average assumptions:

	RELIANT ENERGY		
	1999	2000	2001
Expected life in years	5	5	5
Interest rate	5.10%	6.57%	4.87%
Volatility	21.23%	24.00%	31.91%
Expected common stock dividend	$ 1.50	$ 1.50	$ 1.50

	RELIANT RESOURCES
	2001
Expected life in years	5
Interest rate	4.94%
Volatility	42.65%

Pro forma information for 1999, 2000 and 2001 is provided below to take into account the amortization of stock-based compensation to expense on a straight-line basis over the vesting period. Had compensation costs been determined as prescribed by SFAS No. 123, the Company's net income would have been reduced by $1.3 million, $2.6 million and $22.5 million in 1999, 2000 and 2001, respectively.

Subject to the Distribution, Reliant Energy expects to convert all outstanding Reliant Energy stock options granted prior to May 4, 2001 to a combination of adjusted Reliant Energy stock options and Company stock options. For the converted stock options, the sum of the intrinsic value of Reliant Energy stock options immediately prior to the record date of the Distribution will equal the sum of the intrinsic values of the adjusted Reliant Energy stock options and the Company stock options granted immediately after the record date of the Distribution. As such, Reliant Energy employees who do not work for the Company will hold stock options of the Company.

(b) PENSION.

Effective March 1, 2001, the Company no longer accrued benefits under a noncontributory pension plan for its domestic non-union employees (Resources Participants). Effective March 1, 2001, each Resources Participant's unvested accrued benefit was fully vested and a one-time benefit enhancement was provided to some qualifying participants. After the Distribution, each Resources Participant may elect to have his accrued benefit (a) left in the Reliant Energy pension plan, (b) rolled over to a new Company savings plan or an individual IRA account, or (c) paid in a lump-sum or annuity distribution. During 2001, the Company incurred a charge to earnings of approximately $83 million (pre-tax) for the one-time benefit enhancement discussed above and a gain of $23 million (pre-tax) related to the curtailment of Reliant Energy's noncontributory and non-qualified pension plans. In connection with the Distribution, the Company expects to incur a loss of $57 million (pre-tax) related to the settlement of Reliant Energy's pension plan and non-qualified pension plans. These charges include costs incurred for former employees of Reliant Energy, primarily corporate support and executive officers, who transferred to the Company on January 1, 2001.

Except for its foreign subsidiaries and REMA union employees, prior to March 1, 2001, the Company participated in Reliant Energy's noncontributory pension plan. REMA union employees participate in a REMA noncontributory pension plan. Effective January 1, 1999, Reliant Energy amended and restated its pension plan and converted the present value of the accrued benefits under the existing pension plan into a cash balance pension plan. Under the cash balance formula, each participant has an account, for recordkeeping purposes only, to which credits are allocated annually based on a percentage of the participant's pay. The applicable percentage for 1999, 2000 and first two months of 2001 was 4% in each period.

Reliant Energy's 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 common stocks and high-quality, interest-bearing obligations. As of December 31, 2001, approximately 9% of the Reliant Energy noncontributory pension plan assets was an investment in Reliant Energy common stock.

REPGB is a foreign subsidiary of the Company and participates along with other companies in the Netherlands in making payments to pension funds which are not administered by the Company. The Company treats these as a defined contribution pension plan which provides retirement benefits for most of its employees. The contributions are principally based on a percentage of the employee's base compensation and charged against income as incurred. This expense was $1.7 million for the three months ended December 31, 1999, and $6.4 million and $5.6 million for 2000 and 2001, respectively.

Net pension cost for the Company (excluding REPGB) includes the following components:

	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
		(IN MILLIONS)	
Service cost - benefits earned during the period	$ 1.8	$ 3.6	$ 3.5
Interest cost on projected benefit obligation ..	1.8	2.1	8.2
Expected return on plan assets	(2.3)	(3.3)	(11.9)
Curtailment and benefits enhancements	--	--	44.9
Net amortization	0.1	(0.3)	0.6
Net pension cost	$ 1.4	$ 2.1	$ 45.3

Following are reconciliations of the Company's beginning and ending balances of its retirement plan benefit obligation, plans assets and funded status for 2000 and 2001 (excluding REPGB). The prepaid pension asset is primarily recorded in other long-term assets.

	YEAR ENDED DECEMBER 31, 2000	YEAR ENDED DECEMBER 31, 2001
	(IN MILLIONS)	
CHANGE IN BENEFIT OBLIGATION		
Benefit obligation, beginning of year	$ 24.0	$ 28.7
Service cost	3.6	3.5
Interest cost	2.1	8.2
Curtailments and benefits enhancement	--	55.8
Transfers from affiliates	--	35.4
Acquisitions	1.0	--
Actuarial (gain) loss	(2.0)	6.0
Benefit obligation, end of year	$ 28.7	$ 137.6
CHANGE IN PLANS ASSETS		
Plans assets, beginning of year	$ 31.0	$ 27.3
Transfers/allocations from affiliates	--	124.8
Employer contributions	--	0.7
Acquisitions	1.0	--
Actual investment return	(4.7)	--
Plans assets, end of year	$ 27.3	$ 152.8
RECONCILIATION OF FUNDED STATUS		
Funded status	$ (1.4)	$ 15.2
Unrecognized transition asset	--	(0.2)
Unrecognized prior service cost	(2.8)	--
Unrecognized actuarial loss	4.6	14.8
Net amount recognized at end of year	$ 0.4	$ 29.8
ACTUARIAL ASSUMPTIONS		
Discount rate	7.5%	7.25%
Rate of increase in compensation levels	3.5 - 5.5%	3.5 - 5.5%
Expected long-term rate of return on assets ..	10.0%	9.5%

As all distributions from the Reliant Energy noncontributory plan to Resources Participants after the Distribution will be made from Reliant Energy plan assets, actual investment returns on plan assets above or below expected returns on plan assets are included in "transfers/allocations from affiliates" in the above reconciliation in 2001.

The accumulated benefit obligation and fair value of plan assets for the REMA noncontributory pension plan were $4.7 million and $1.7 million, respectively, as of December 31, 2001.

The actuarial loss during 2001 was primarily due to the decrease in discount rate and changes in demographics of the participants.

In addition to the noncontributory pension plans discussed above, the Company participates in Reliant Energy's non-qualified pension plans which allow participants to retain the benefits to which they would have been entitled under Reliant Energy'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. The expense associated with these non-qualified plans was $2 million in 2001 and was immaterial in 1999 and 2000. The accrued benefit liability for the nonqualified pension plan was $1 million and $30 million as of December 31, 2000 and December 31, 2001, respectively. In addition, the accrued benefit liabilities as of December 31, 2001 include the recognition of minimum liability adjustments of $11 million, which is reported as a component of comprehensive income net of income tax effects. Effective March 1, 2001, the Company no longer provides future non-qualified pension benefits to its employees.

(c) SAVINGS PLAN.

Except for its foreign subsidiaries and REMA employees, the Company participates in Reliant Energy's employee savings plan that is a tax qualified plan under Section 401(a) of the Internal Revenue Code of 1986, as amended (Code), and includes a cash or deferred arrangement under Section 401(k) of the Code. REMA employees participate in REMA employee savings plans that are tax-qualified plans under Section 401(a) of the Code and include cash or deferred arrangements under Section 401(k) of the Code. Under the plans, participating employees may contribute a portion of their compensation, pre-tax or after-tax, generally up to a maximum of 16% of compensation. The Company matches a portion of each employee's compensation contributed, with some matching contributions subject to a vesting schedule. Through March 1, 2001, a substantial portion of Reliant Energy's employee savings plan match was made in Reliant Energy common stock.

Effective March 1, 2001, Reliant Energy amended its savings plan and REMA's non-union employee savings plan to generally provide for (a) employer matching contributions equal to 100% of the first 6% of each employee's contributions to the plan, (b) a 2% employer contribution on a payroll basis for 2002, limited to the first $85,000 of compensation, and (c) discretionary employer contributions up to 3% at the end of the plan year based on each employee's eligible compensation. Effective March 1, 2001, all prior and future employer contributions on behalf of such employees are fully vested.

The Company's savings plan benefit expense was $2 million, $6 million and $20 million in 1999, 2000 and 2001, respectively.

On February 1, 2002, the Company established an employee savings plan that is a tax-qualified plan under Section 401(a) of the Code and includes a cash or deferred arrangement under Section 401(k) of the Code for substantially all its non-union employees except for its foreign subsidiaries' employees. The Company savings plan match and any payroll period discretionary employer contribution will be made in cash; any discretionary annual employer contribution may be made in the Company's common stock, cash or both. Beginning January 1, 2002, the Company established a separate savings plan for its union employees.

(d) POSTRETIREMENT BENEFITS.

Effective March 1, 2001, the Company discontinued providing subsidized postretirement benefits to its domestic non-union employees. The Company incurred a pre-tax loss of $40 million during the first quarter of 2001 related to the curtailment of the Company's postretirement obligation. In connection with the Distribution, the Company expects to incur a pre-tax gain of $21 million related to the settlement of the postretirement benefit obligation. These charges include the effect of the curtailment and settlement of the postretirement obligation for former employees of Reliant Energy, primarily corporate support and executive officers, who transferred to the Company on January 1, 2001. Prior to March 1, 2001, through a Reliant Energy subsidized postretirement plan, the Company provided some postretirement benefits for substantially all of its retired employees. The Company continues to provide subsidized postretirement benefits to certain union employees.

REPGB provides some postretirement benefits (primarily medical care and life insurance benefits) for its retired employees, substantially all of whom may become eligible for these benefits when they retire.

Under SFAS No. 106, "Employer's Accounting for Postretirement Benefits Other Than Pensions" (SFAS No. 106), postretirement benefits are accounted for on an accrual basis using a specified actuarial method based on benefits and years of service. The Company was amortizing over a 20-year period approximately $4 million to cover the "transition cost" of adopting SFAS No. 106. Upon curtailment of the plan, the remaining transition cost was recognized. The Company funds its portion of the postretirement benefits on a pay-as-you-go basis.

Net postretirement benefit cost for the Company includes the following components:

	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
		(IN MILLIONS)	
Service cost - benefits earned during the period	$ 0.5	$ 1.4	$
Interest cost on projected benefit obligation	1.0	2.0	
Curtailment	--	--	3
Net amortization	0.4	0.4	
Net postretirement benefit cost	$ 1.9	$ 3.8	$ 4

Following are reconciliations of the Company's beginning and ending balances of its postretirement benefit plans' benefit obligation and funded status for 2000 and 2001:

	YEAR ENDED DECEMBER 31, 2000	YEAR ENDED DECEMBER 31, 2001
	(IN MILLIONS)	
CHANGE IN BENEFIT OBLIGATION		
Benefit obligation, beginning of year	$ 31.5	$ 35.0
Service cost	1.4	2.0
Interest cost	2.0	2.7
Benefit payments	(1.0)	(1.4)
Transfers from affiliates	--	9.8
Acquisitions	2.2	--
Foreign exchange impact	(1.4)	(2.5)
Actuarial loss	0.3	2.9
Benefit obligation, end of year	$ 35.0	$ 48.5
RECONCILIATION OF FUNDED STATUS		
Funded status	$ (35.0)	$ (48.5)
Unrecognized transition obligation	2.7	--
Unrecognized prior service cost	2.9	--
Unrecognized actuarial loss	1.2	5.7
Net amount recognized at end of year	$ (28.2)	$ (42.8)
ACTUARIAL ASSUMPTIONS		
Discount rate	6.6 - 7.5%	6.6 - 7.25%
Rate of increase in compensation levels ...	2.0%	2.0%

(e) POSTEMPLOYMENT BENEFITS.

The Company records 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 not material in 1999, 2000 and 2001.

(f) EMPLOYEE STOCK PURCHASE PLAN.

In the second quarter 2001, the Company established the Employee Stock Purchase Plan (ESPP). Under the ESPP, employees may contribute up to 15% of their compensation, as defined, towards the purchase of shares of the Company's common stock at a price of 85% of the lower of the market value at the beginning of the purchase period or end of each six-month purchase period. The initial purchase period began on the date of the IPO and ended December 31, 2001. The market value of the shares acquired by a participant in any year may not exceed $25,000. In January 2002, 550,781 shares were sold to employees under the ESPP at a price of $14.07 per share, related to the initial purchase period.

(g) OTHER NON-QUALIFIED PLANS.

Through December 31, 2001, certain eligible employees participated in Reliant Energy's deferred compensation plans, which permit participants to elect each year to defer a percentage of that year's salary (up to 100%) and up to 100% of that year's annual bonus. In general, employees who attain the age of 60 during employment and participate in Reliant Energy's deferred compensation plans may elect to have their deferred compensation amounts repaid in (a) fifteen equal annual installments commencing at the later of age 65 or termination of employment or (b) a lump-sum distribution following termination of employment. Interest generally accrues 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. On January 1, 2001, some employees of Reliant Energy, primarily corporate support and executive officers, transferred to the Company. As of January 1, 2001, the discounted deferred compensation obligation of $13 million attributable to these employees was transferred to the Company. The Company recorded interest expense related to its deferred compensation obligation of approximately $1 million during 1999 and 2000 and $4 million during 2001. The discounted deferred compensation obligation recorded by the Company was $7 million and $29 million as of December 31, 2000 and 2001, respectively. Each Reliant Resources participant has elected to have his non-qualified deferred compensation plan account balance, after the Distribution: (a) placed in a new Reliant Resources deferred compensation plan, which generally mirrors the former Reliant Energy deferred compensation plans, or (b) rolled over to the new non-qualified deferred compensation plan discussed below.

Effective January 1, 2002, select key and highly compensated employees were eligible to participate in a new Company nonqualified 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 Reliant Resources' 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. The Company funds 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 the Company's designated investment funds within the rabbi trust.

(h) OTHER EMPLOYEE MATTERS.

As of December 31, 2001, approximately 31% of the Company's employees are subject to collective bargaining arrangements, of which contracts covering 17% of the Company's employees will expire prior to December 31, 2002. Of these employees subject to collective bargaining agreements, 48% are employed by REPGB in the Netherlands.

(12) INCOME TAXES

The components of income before taxes are as follows:

	YEAR ENDED DECEMBER 31,		
	1999	2000	2001

		(IN MILLIONS)	
United States	$ 0.3	$ 178.5	$ 720.5
Foreign	26.3	112.6	105.5
Income before income taxes	$ 26.6	$ 291.1	$ 826.0

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

	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
		(IN MILLIONS)	
Current			
Federal	$ (13.6)	$ 99.7	$ 247.6
State	0.6	16.4	4.3
Foreign	--	--	(2.7)
Total current	(13.0)	116.1	249.2
Deferred			
Federal	16.4	(28.2)	10.7
State	(0.8)	0.7	15.7
Foreign	--	--	(4.0)
Total deferred	15.6	(27.5)	22.4
Income tax expense	$ 2.6	$ 88.6	$ 271.6

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

	YEAR ENDED DECEMBER 31,		
	1999	2000	
		(IN MILLIONS)	
Income before income taxes	$ 26.6	$ 291.1	$
Federal statutory rate	35%	35%	
Income tax expense at statutory rate	9.3	101.9	
Net addition (reduction) in taxes resulting from:			

State income taxes, net of valuation allowances and federal income tax benefit	(0.1)	11.1	
REPGB tax holiday	(10.1)	(37.8)	
Goodwill amortization	1.4	2.1	
Federal and foreign valuation allowance	1.6	12.8	
Other, net	0.5	(1.5)	
Total	(6.7)	(13.3)	
Income tax expense	$ 2.6	$ 88.6	$
Effective rate	9.6%	30.4%	

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%. The effect of the change in the enacted tax rate was not material to the Company's results of operations.

Undistributed Earnings of Foreign Subsidiaries. The undistributed earnings of foreign subsidiaries aggregated $266 million as of December 31, 2001, which, under existing tax law, will not be subject to U.S. income tax until distributed. Provisions for U.S. 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, the Company will be subject to U.S. income taxes net of allowable foreign tax credits.

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:

	YEAR ENDED DECEMBER 31,	
	2000	2001
	(IN MILLIONS)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts and credit provisions	$ 16.0	$ 59.5
Other	--	4.8
Total current deferred tax assets	16.0	64.3
Non-current:		
Employee benefits	17.8	44.3
Operating loss carryforwards	21.8	18.1
Environmental reserves	19.5	15.0
Foreign exchange gains	11.5	11.1

Non-trading derivative liabilities, net	--	133.7
Non-derivative stranded costs liability	--	73.1
Other	34.7	30.1
Valuation allowance	(20.3)	(15.6)
Total non-current deferred tax assets	85.0	309.8
Total deferred tax assets	$ 101.0	$ 374.1
Deferred tax liabilities:		
Current:		
Trading and marketing assets, net	$ 16.0	$ 48.4
Non-trading derivative assets, net	--	0.8
Hedges of net investment in foreign subsidiaries	--	52.1
Total current deferred tax liabilities	16.0	101.3
Non-current:		
Depreciation	108.5	133.6
Trading and marketing assets, net	--	27.5
Stranded costs indemnification receivable	--	73.1
Other	7.7	29.3
Total non-current deferred tax liabilities	116.2	263.5
Total deferred tax liabilities	$ 132.2	$ 364.8
Accumulated deferred income taxes, net	$ 31.2	$ 9.3

Tax Attribute Carryforwards. At December 31, 2001, the Company had approximately $6 million, $132 million and $45 million of federal, state and foreign net operating loss carryforwards, respectively. The federal and state loss carryforwards can be carried forward to offset future income through the year 2021. The foreign losses can be carried forward indefinitely.

The valuation allowance reflects a net increase of $17 million in 2000 and a $5 million net decrease in 2001. These net changes resulted from a reassessment of the Company's future ability to use federal, state and foreign tax net operating loss carryforwards.

As discussed in Note 13(f), 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 of the above, the Company 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 the Company's statutorily allocated share of these gas supply and electricity contracts. The Company believes that the costs incurred by REPGB subsequent to the tax holiday ending in 2001 related to these contracts will be deductible for Dutch tax purposes. However, due to the uncertainties related to the deductibility of these costs, the Company has recorded an offsetting liability in other liabilities of $127 million as of December 31, 2001.

(13) COMMITMENTS AND CONTINGENCIES

(a) COMMITMENTS AND GUARANTEES.

As of December 31, 2001, the Company's Wholesale Energy segment had entered into commitments associated with various non-rate regulated electric generating projects, including commitments for the purchase of combustion turbines, aggregating $440 million. In addition, Wholesale Energy has options to purchase additional generating equipment for a total estimated cost of $42 million for future generation projects. The Company is actively attempting to remarket this equipment.

The Company is 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 the Company's Consolidated Balance Sheet as of December 31, 2001 as these contracts meet the SFAS No. 133 exception to be classified as "normal purcha