RELIANT ENERGY INC
Form 10-K
March 15, 2006

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PART IV

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2005

or

o **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 Energy, Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**76-0655566**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
1000 Main Street **Houston, Texas 77002**	**(713) 497-3000**
(Address and Zip Code of Principal Executive Offices)	(Registrant's Telephone Number, Including Area Code)

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý

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 ý No o

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. ý

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. Large accelerated filer ý Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No ý

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was $3,320,080,867 (computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on June 30, 2005, the last business day of the registrant's most recently completed second fiscal quarter).

As of March 1, 2006, the registrant had 305,417,242 shares of common stock outstanding and no shares of common stock were held by the registrant as treasury stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for its 2006 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2005, are incorporated by reference into Part III of this Form 10-K.

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Forward-Looking Information

Projections, estimates or assumptions about revenues, costs, income, cash flow and other future events are called "forward-looking statements." In some cases, you can identify forward-looking statements by words like "anticipate," "estimate," "believe," "intend," "may," "expect" or similar words. Forward-looking statements are not guarantees of future performance. Actual results may differ from forward-looking statements. Each forward-looking statement speaks only as of its date and we are under no obligation to update these statements. For information about factors that could cause our actual results to differ from forward-looking statements, see "Risk Factors" in Item 1A of this report.

GLOSSARY OF TECHNICAL TERMS

Cal ISO	California Independent System Operator.
capacity factor	The ratio of actual net electricity generated to energy that could have been generated at continuous full-power operation during the year.
CenterPoint	CenterPoint Energy, Inc. and its subsidiaries, on and after August 31, 2002, and Reliant Energy, Incorporated and its subsidiaries, prior to August 31, 2002.
CO_2	Carbon dioxide.
Commercial capacity factor	The percentage of the number of hours that our plants run divided by the number of hours that would be dispatched based on the market demand.
contribution margin	Revenues less (a) purchased power, fuel and cost of gas sold, (b) operation and maintenance, (c) selling and marketing and (d) bad debt expense.
EBITDA	Earnings (loss) before interest expense, interest income, income taxes, depreciation and amortization expense.
EITF	Emerging Issues Task Force.
EITF No. 02-03	EITF Issue No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities."
EITF No. 03-11	EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' as Defined in EITF No. 02-03."
EPA	United States Environmental Protection Agency.
ERCOT	Electric Reliability Council of Texas.
ERCOT ISO	ERCOT Independent System Operator.
ERCOT Region	The electric market operated by ERCOT.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
gross margin	Revenues less purchased power, fuel and cost of gas sold.
GWh	Gigawatt hour.
ISO	Independent system operator.
KWh	Kilowatt hour.
LIBOR	London Inter Bank Offering Rate.
MISO	Midwest Independent Transmission System Operator.
MMbtu	One million British thermal units.
MW	Megawatt.
MWh	Megawatt hour.
net generating capacity	The average of a facility's summer and winter generating capacities, net of auxiliary power.
NO_x	Nitrogen oxide.
NYMEX	New York Mercantile Exchange.
Orion Power	Orion Power Holdings, Inc. and its subsidiaries.
PEDFA	Pennsylvania Economic Development Financing Authority.
PJM	PJM Interconnection, LLC.
PJM Market	The wholesale and retail electric market operated by PJM primarily in all or parts of Delaware, the District of Columbia, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia.
PUCT	Public Utility Commission of Texas.
REMA	Reliant Energy Mid-Atlantic Power Holdings, LLC and its subsidiaries.
RTO	Regional transmission organization.
SEC	United States Securities and Exchange Commission.
SO_2	Sulfur dioxide.
Texas GENCO	Texas Genco Holdings, Inc. and its subsidiaries.

PART I

Item 1. *Business*.

General

We provide electricity and energy services to retail and wholesale customers through two business segments.

Retail energy provides electricity and energy services to approximately 1.9 million retail electricity customers in Texas, including residential and small business customers and large commercial, industrial and governmental/institutional customers. We also serve commercial, industrial and governmental/ institutional customers in the PJM Market.

Wholesale energy provides electricity and energy services in the competitive wholesale energy markets in the United States. In this connection, we own and operate or contract for power generation capacity. As of December 31, 2005, we had approximately 15,956 MW of owned or leased generation capacity in operation.

For information about our corporate history, business segments and disposition activities, see notes 1, 17, 19 and 20 to our consolidated financial statements and "Selected Financial Data" in Item 6 of this Form 10-K.

Retail Energy

Our retail energy segment provides electricity and energy services to customers primarily in Texas. We also have retail energy operations in the PJM Market, and we regularly evaluate entering other markets.

As a retail electricity provider, we are responsible for arranging for the transmission and delivery of electricity to our customers, billing customers and collecting payment for electricity sold, and maintaining 24-hour call centers to provide customer service. We purchase the electricity we sell to customers from generation companies, utilities, power marketers and other retail energy companies. As of December 31, 2005, we had contracts to purchase generation capacity for our Texas retail customers averaging 9,166 MW per month in 2006, 5,965 MW per month in 2007 and 1,395 MW per month in 2008. These amounts exclude commitments as of December 31, 2005, related to a contract terminated in early January 2006. Based on current market conditions, existing retail sales commitments and current load forecasts, we estimate that these contracts will supply approximately 97% of our retail energy segment's current capacity requirements for 2006 for our Texas retail customers.

Residential and Small Business Customers

Our retail business for residential and small business customers is primarily concentrated in Texas. Based on metered locations, as of December 31, 2005, we had approximately 1.7 million residential and 203,000 small business customers, making us the second largest residential electricity provider in Texas. Approximately 75% of our customers are in the Houston area. We also have customers in other Texas cities, including Dallas, Ft. Worth and Corpus Christi.

Commercial, Industrial and Governmental/Institutional Customers

In Texas and the PJM Market, we market electricity and energy services to large commercial, industrial and governmental/institutional customers. These customers include refineries, chemical plants, manufacturing facilities, hospitals, universities, governmental agencies, restaurants and other facilities. Based on metered locations, as of December 31, 2005, we had approximately 36,000 commercial, industrial and governmental/institutional customers.

Operations Data

The following tables present information about our retail electricity sales and customers in various markets:

	2005	2004	2003
		(GWh)	
Electricity Sales to End-Use Retail Customers:			
Texas:			
Residential:			
Price-to-beat	17,981	19,315	20,738
Non price-to-beat	6,470	4,516	2,070
Total residential	24,451	23,831	22,808
Small business:[1]			
Price-to-beat	5,183	7,166	10,845
Non price-to-beat	2,882	1,924	1,053
Total small business	8,065	9,090	11,898
Large commercial, industrial and governmental/institutional[2][3]	28,604	31,278	28,788
Total Texas	61,120	64,199	63,494
Outside of Texas:			
Commercial, industrial and governmental/institutional	6,155	3,635	785
Total Outside of Texas	6,155	3,635	785
Total	67,275	67,834	64,279

(1) "Small business" customers are our retail commercial customers that have a peak demand of less than one MW.

(2) "Large commercial, industrial and governmental/institutional" customers are our retail commercial customers that have a peak demand of more than one MW.

(3) These volumes include customers of the General Land Office for whom we provide services.

	December 31,	
	2005	2004
	(in thousands, metered locations)	
Retail Customers:		
Texas:		
Residential:		

	December 31,	
Price-to-beat	1,191	1,313
Non price-to-beat	483	334
Total residential	1,674	1,647
Small business:		
Price-to-beat	137	163
Non price-to-beat	66	30
Total small business	203	193
Large commercial, industrial and governmental/institutional[1]	34	40
Total Texas	1,911	1,880
Outside of Texas:		
Commercial, industrial and governmental/institutional	2	1
Total Outside of Texas	2	1
Total	1,913	1,881

(1) These volumes include customers of the General Land Office for whom we provide services.

	2005	2004	2003
	(in thousands, metered locations)		
Weighted Average Retail Customer Count:			
Texas:			
Residential:			
Price-to-beat	1,250	1,360	1,408
Non price-to-beat	396	271	117
Total residential	1,646	1,631	1,525
Small business:			
Price-to-beat	147	174	194
Non price-to-beat	43	26	17
Total small business	190	200	211
Large commercial, industrial and governmental/institutional(1)	36	40	33
Total Texas	1,872	1,871	1,769
Outside of Texas:			
Commercial, industrial and governmental/institutional(2)	2	1	
Total Outside of Texas	2	1	
Total	1,874	1,872	1,769

(1) These amounts include volumes of customers of the General Land Office for whom we provide services.

(2) For 2003, our weighted average retail customer count was 165.

Wholesale Energy

As of December 31, 2005, we owned, had an interest in or leased 36 operating electric power generation facilities with an aggregate net generating capacity of 15,956 MW in five regions of the United States. The net generating capacity of these facilities consists of approximately 38% base-load, 35% intermediate and 27% peaking capacity.

We sell electricity and energy services from our generation portfolio to investor-owned utilities, municipalities, cooperatives and other companies that serve end users or purchase power at wholesale for resale. We also sell these products in hour-ahead, day-ahead, forward, bilateral and ISO markets. Because our facilities are not subject to traditional cost-based regulation, we can generally sell electricity at market-determined prices. The following table identifies the principal markets where we own, lease and have under contract wholesale generation assets:

Region	Principal Markets
PJM	Illinois, New Jersey and Pennsylvania
MISO	Illinois, western Pennsylvania and Ohio
Southeast	Florida, Mississippi and Texas (non-ERCOT)
West	California and Nevada
ERCOT	ERCOT

We also lease transportation and storage capacity in the Eastern and Western United States to provide natural gas to our generation assets.

In the fourth quarter of 2005, we commenced an evaluation of our wholesale energy segment's hedging strategy and use of capital. In February 2006, we decided to substantially reduce new hedges of our generation. For additional information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Business Overview" in Item 7 of this Form 10-K.

Operations Data

The following table presents information about our wholesale power generation, purchase and sales volumes:

	2005	2004	2003
		(GWh)	
Power Generation:[1]			
Wholesale net power generation volumes	33,709	32,562	35,135
Wholesale power purchase volumes	1,838	1,840	60,983
Wholesale power sales volumes[2]	35,547	34,402	96,118

(1) These amounts include physically delivered volumes, hedge activity related to our power generation portfolio and volumes associated with our legacy trading activities. These amounts exclude (a) volumes associated with our discontinued operations (see note 20 to our consolidated financial statements), (b) generation from facilities where the generation is sold by a third party pursuant to a tolling agreement, (c) generation from facilities that are accounted for as an equity method investment and (d) physical transactions that are settled prior to delivery.

(2) For 2005, 2004 and 2003, these amounts include sales to our retail energy segment of 11,780 GWh, 8,909 GWh and 2,003 GWh, respectively.

The following table presents information about our wholesale natural gas sales volumes:

	2005	2004	2003
		(MMbtu)	
Net natural gas sales volumes	146	80	

The following table describes our electric power generation facilities and net generating capacity by region as of December 31, 2005 (excluding generation facilities included in discontinued operations and facilities subsequently sold or retired from service):

Region	Number of Generation Facilities	Net Generating Capacity (MW)	Fuel Type	Dispatch Type
PJM				
Operating[1]	20	7,264	Coal/Gas/Oil/Dual	Base-load/Intermediate/Peaking
Mothballed	1	68	Dual	Peaking
Combined	21	7,332		
MISO				
Operating	4	1,671	Coal/Gas/Oil	Base-load/Intermediate/Peaking
Southeast				
Operating[2][3]	5	2,215	Gas/Dual	Base-load/Intermediate/Peaking
Mothballed	1	800	Gas	Intermediate
Combined	6	3,015		
West				
Operating	6	3,976	Gas/Dual	Base-load/Intermediate/Peaking
ERCOT				
Operating	1	830	Gas	Base-load
Total				
Operating	36	15,956		
Mothballed	2	868		
Combined	38	16,824		

(1) We lease a 100%, 16.67% and 16.45% interest in three Pennsylvania facilities having 614 MW, 1,711 MW and 1,712 MW of net generating capacity, respectively, through facility lease agreements expiring in 2026, 2034 and 2034, respectively. The table includes our share of the capacity of these facilities.

(2) We own a 50% interest in one of these facilities having a net generating capacity of 108 MW. An unaffiliated party owns the other 50%. The table includes our proportionate share of the capacity of this facility.

(3) We are party to tolling agreements entitling us to 100% of the capacity of two Florida facilities having 630 MW and 474 MW of net generating capacity, respectively. These tolling agreements expire in 2012 and 2007, respectively, and are treated as operating leases for accounting purposes.

The following table provides information regarding generation output:

	2005	%	Capacity Factor	2004	%	Capacity Factor
Dispatch Type (GWh):[1]						
Base-load	33,301	87%	63%	30,985	84%	58%
Intermediate	3,610	9	6%	4,922	13	3%
Peaking	1,495	4	4%	1,140	3	9%
Total	38,406	100%	26%	37,047	100%	25%
Fuel Type (GWh):[1]						
Coal	24,144	63%	60%	21,229	57%	53%
Natural gas	12,195	32	17%	13,473	37	19%
Oil	24		1%	59		2%
Dual	1,919	5	6%	2,027	6	7%
Hydro	42		11%	109		28%
Renewables	82		36%	150		66%
Total	38,406	100%	26%	37,047	100%	25%

(1) Excludes operations classified as discontinued operations. See note 20 to our consolidated financial statements.

Regulation

Texas

We are certified by the PUCT to provide retail electric service in Texas. Outside Houston, we sell electricity at unregulated prices. In Houston, we can also sell electricity without pricing restrictions. However, until January 1, 2007, we must continue to make electricity available to residential and small business customers at the PUCT-approved "price-to-beat." As of December 31, 2005, the average "price-to-beat" was 16.3 cents per KWh for residential customers using 1,000 KWh per month and 13.6 cents per KWh for small business customers using 15,000 KWh per month.

From November 3 through December 31, 2005, we did not charge the full amount of the approved "price-to-beat" rate to our "price-to-beat" customers. Instead, we charged a price based on an imputed natural gas price of $9.74/MMbtu. In addition, from January 1 through March 15, 2006, we committed to the PUCT to charge existing residential "price-to-beat" customers a price based on an imputed natural gas price of $10.78/MMbtu rather than the current "price-to-beat" rate, which is based on a gas price of $11.387/MMbtu. From March 16 through June 30, 2006, we committed to the PUCT to not charge these residential customers a price higher than the "price-to-beat" rate based on an imputed gas price of $11.387/MMbtu.

Under current PUCT rules, we can request an adjustment to the fuel factor component of the "price-to-beat" twice a year based on significant changes in natural gas prices and purchased energy. The following table shows historical adjustments to our "price-to-beat" fuel factor:

Date Requested	Date Granted	Natural Gas Price in Fuel Factor Before Request (per MMbtu)	Natural Gas Price in Fuel Factor After Request (per MMbtu)
January 2003	March 2003	$ 4.017	$ 4.956
June 2003	July 2003	$ 4.956	$ 6.100
November 2004	December 2004	$ 6.100	$ 7.499
October 2005	November 2005	$ 7.499	$ 11.387[(1)]

(1) See discussion above regarding discounts.

In addition to the PUCT, our activities in Texas are subject to standards and regulations adopted by ERCOT. See "Risk Factors" in Item 1A of this Form 10-K.

Other States

We operate electric generation facilities in regions administered by the following ISOs/RTOs: PJM, Cal ISO and MISO, which operate under FERC-established tariffs and regulations. In each of these regions, the market rules include price limits or caps applicable to all generators. In addition, at the request of the local system operator, we may be required to operate our plants at fixed prices or subject to temporary price caps to maintain the reliability of the local grid system. The ISOs also impose numerous other requirements relative to the manner in which we must operate our plants.

Federal Energy Regulatory Commission

A number of our subsidiaries are public utilities under the Federal Power Act. As public utilities, these entities must sell power at either cost-based rates or market-based rates, if market-based rates authority has been granted by FERC. Each of our FERC-jurisdictional subsidiaries has been granted market-based rate authority, although some services sold by some of these entities are sold at cost-based rates. These subsidiaries are subject to FERC rules and oversight regulations.

Seasonality and Competition

The retail and wholesale energy industries are intensely competitive. Our competitors include merchant energy companies, utilities, retail electric service providers and other companies, including in recent years companies owned by investment banking firms, hedge funds and private equity funds. Our principal competitors in the retail electricity markets outside of Houston are typically incumbent utility companies or their affiliates, which have the advantage of long-standing relationships with customers. In general, competition in the retail and wholesale energy markets is on the basis of price, service and product offerings, as well as market perceptions of creditworthiness. For a discussion of how seasonality impacts our business and for additional information on the effect of competition, see "Risk Factors" in Item 1A of this Form 10-K and note 16 to our consolidated financial statements.

Environmental Matters

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 compounds into the 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.

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For the continued economic operation of our plants, we will construct, modify and retrofit equipment and clean up or decommission our disposal or fuel storage areas and other locations. Based on existing regulations, we estimate that we will spend approximately $50 million to $70 million in 2006, $85 million to $120 million in 2007 and $270 million to $515 million in 2008 through 2011. The above amounts include $8 million for environmental capitalized maintenance projects in 2006 and $20 million for future ash landfill expansions from 2007 through 2011. In addition, $7 million will be spent for remediation of four New Jersey plants through 2011.

Our estimates for compliance with new and emerging environmental regulations are based on our current assessment of items such as the cost of labor and materials and the current state of evolving technologies. Changes to the preceding factors, revisions of regulations, litigation and legislation, as well as other factors, could cause the actual costs to vary outside the range of these estimates.

Air Quality Matters

The Clean Air Act requires the EPA to define standards for air quality that are protective of public health and welfare. The 1990 amendments to the Clean Air Act directed the EPA to implement programs to control ambient ozone, acidic deposition (acid rain) and ozone depleting chemicals, improve visibility in the United States' pristine areas and national parks (regional haze) and reduce emissions of hazardous air pollutants. As a result of these mandates, the EPA implemented a number of emission control programs that affect industrial sources, including power plants, by limiting emissions of NO_x and SO_2, both of which are compounds that result from the combustion of fossil fuels. NO_x and SO_2 are precursors to the formation of acid rain, fine particulate matter and regional haze. NO_x is also a precursor to the formation of ozone.

To comply with these regulations, we must purchase emission allowances and/or upgrade the emissions controls at some of our facilities. As part of our effort to operate our business efficiently, we concluded that since our generating assets dispatch based on market prices, we should maintain an emission allowances inventory that corresponds with forward power sales. We plan to sell some excess emission allowances inventory if the price is equal to or above our fundamental view. See "Risk Factors" in Item 1A and "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources" in Item 7 of this Form 10-K and notes 4 and 19 to our consolidated financial statements.

Regulation of NO_x and SO_2 Emissions

In March 2005, the EPA finalized a regulation, referred to as the Clean Air Interstate Rule, to further reduce emissions of NO_x and SO_2 in the eastern United States in two phases. The first phase, which takes effect in 2009 for NO_x and 2010 for SO_2, requires approximately a 50% reduction in NO_x and SO_2 emissions on an annual basis. The second phase, which takes effect in 2015, requires additional reductions of approximately 10% for a 60% total reduction in NO_x and 15% for a 65% reduction in SO_2. The EPA regulations include the use of cap-and-trade programs to achieve these reductions.

We have undertaken studies to evaluate possible impacts of the Clean Air Interstate Rule and similar legislative and regulatory proposals, which will primarily affect our coal-fired facilities in the eastern United States. Our preliminary estimates of the required capital expenditures, based on an economic analysis that includes plant operability, changes in the emission allowances market and potential impact of state-imposed regulations, range from approximately $295 million to $545 million through 2011 for SO_2 and NO_x. We anticipate that these expenditures would be made over time, with the majority of the expenditures being incurred in 2008 and 2009.

Regulation of Emissions of Mercury and Other Hazardous Air Pollutants

In March 2005, the EPA adopted a national cap-and-trade rule that requires mercury emission reductions in two phases, in 2010 and 2018, with reduction levels set at approximately 30% and 70%, respectively. Despite the finalization of these mercury control regulations, several issues remain that affect the ultimate requirement to control mercury. First, litigation has commenced over the final form of the rule. The outcome of this litigation is uncertain, and could result in a requirement to control mercury on a facility-by-facility basis, instead of under a cap-and-trade program. Second, states are free to adopt their own mercury regulations that are stricter than those finalized by EPA. Several states, including Pennsylvania, are considering adopting stricter regulations for mercury.

Given the uncertainty around the final outcome of state efforts to regulate mercury and litigation surrounding the federal mercury regulations, preliminary estimates indicate that our emission control expenditures for mercury compliance could range between $35 million and $80 million through 2009. We anticipate that these expenditures would be made over time, with the majority of the expenditures being incurred in 2008 and 2009. These estimates are incremental to the overall capital expenditures range for SO_2 and NO_x.

Greenhouse Gas Emissions

The Kyoto Protocol, which became effective in February 2005, requires ratifying countries to achieve substantial reductions of CO_2 and other greenhouse gases between 2008 and 2012. In December 2005, the United Nations Climate Change Conference in Montreal, Canada adopted over 40 provisions to implement this treaty. Although the United States Congress indicated that it does not intend to ratify the treaty at this time, any future limitations on power plant CO_2 emissions could have a material impact on all fossil fuel-fired facilities, including those belonging to us.

There continues to be a debate within the United States over the direction of domestic climate change policy. The United States Congress is currently considering several bills that would impose mandatory limitation of CO_2 emissions for the domestic power generation sector; and several states, primarily in the northeastern and coastal western United States, are actively developing or considering state-specific or regional regulatory initiatives to stimulate CO_2 emission reductions in the electric utility industry. The specific impact on our business will depend upon the form of emissions-related legislation or regulations ultimately adopted by the federal government or states in which our facilities are located.

Water Quality Matters

In July 2004, the EPA promulgated final regulations relating to the design and operation of cooling water intake structures at existing power plants. The regulations establish "best technology available" standards to protect aquatic organisms in the vicinity of our plant intakes. In 2004, we initiated site-specific evaluations to determine our practicable compliance options and the associated costs. The EPA developed facility-specific cost assumptions that provide an interim means to benchmark our future compliance expenditures. Using these assumptions, we anticipate capital expenditures of approximately $50 million between 2008 and 2010. Several environmental organizations and Attorneys General of six northeastern states have filed lawsuits against the EPA alleging the regulations are insufficient for protection of the state waters and fisheries. The outcome of this litigation on the regulations cannot be determined at this time, but it could significantly affect the final costs of our compliance.

Other

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. We have accounted for the proper management, abatement and disposal of asbestos and lead-based paint at our facilities in our financial planning. See note 2(q) to our consolidated financial statements.

Under the Comprehensive Environmental Response Corporation and Liability Act of 1980 and similar state laws, owners and operators of facilities from or at which there has been a release or threatened release of hazardous substances, together with those who have transported or arranged for the disposal of those substances, are liable for the costs of responding to that release or threatened release, and the restoration of natural resources damaged by any such release. We are not aware of any liabilities under the Act that would have a material adverse effect on our results of operations, financial position or cash flows.

For additional information regarding environmental matters, see "Risk Factors" in Item 1A of this Form 10-K and note 12(b) to our consolidated financial statements.

Employees

As of December 31, 2005, we had 3,675 full-time and part-time employees. Of these employees, 1,205 are covered by collective bargaining agreements, which expire on various dates through September 2009. We are currently negotiating an agreement with the representative for an additional 49 employees. The following table sets forth the number of our employees by business segment as of December 31, 2005:

Segment	
Retail energy	831
Wholesale energy	2,144
Other operations	700
Total	3,675

Executive Officers

The following table lists our executive officers:

Name	Age[1]	Present Position
Joel V. Staff	62	Chairman and Chief Executive Officer
Mark M. Jacobs	43	Executive Vice President and Chief Financial Officer
Brian Landrum	43	Executive Vice President, Operations
Jerry J. Langdon	54	Executive Vice President, Public and Regulatory Affairs and Corporate Compliance Officer
Michael L. Jines	47	Senior Vice President, General Counsel and Corporate Secretary
Suzanne L. Kupiec	39	Senior Vice President, Risk and Structuring
Karen D. Taylor	48	Senior Vice President, Human Resources and Chief Diversity Officer
Thomas C. Livengood	50	Senior Vice President and Controller

(1) Age is as of February 1, 2006.

Joel V. Staff has served as our Chairman and Chief Executive Officer since April 2003. He was Executive Chairman of National-Oilwell, Inc. (now National Oilwell Varco, Inc.), an international oil and gas services and equipment company, from May 2001 to May 2002 and Chairman, President and Chief Executive Officer from July 1993 to May 2001. He also serves on the Board of Directors of ENSCO International Incorporated and is a member of its Nominating, Governance and Compensation Committee.

Mark M. Jacobs has served as our Executive Vice President and Chief Financial Officer since July 2002. He served as Executive Vice President and Chief Financial Officer of CenterPoint from July 2002 until our separation from it and Managing Director in the Natural Resources Group of Goldman, Sachs & Co., a global investment banking, securities and investment management firm, from 1989 to 2002.

Brian Landrum has served as our Executive Vice President, Operations since February 2006. He was Senior Vice President, Commercial and Retail Operations, IT from February 2005 to February 2006; Senior Vice President, Customer Operations and Information Technology from January 2004 to February 2005; President, Reliant Energy Retail Services from June 2003 to January 2004; Senior Vice President, Retail Operations from August 2001 to May 2003; and Vice President, Internet and E-business from November 1999 to August 2001.

Jerry J. Langdon has served as our Executive Vice President, Public and Regulatory Affairs and Corporate Compliance Officer since January 2004. He was our Executive Vice President and Chief Administrative Officer from May 2003 to January 2004. Before joining us, Mr. Langdon served as President of EPGT Texas Pipeline, L.P., an El Paso Corporation affiliate that provided gas transportation and storage services, from June 2001 until May 2003 and the Managing Partner and Chief Operating Officer of CARLANG Partners, L.P., an investment firm directed toward the energy transportation industry, and President and Chief Executive Officer of CARLANG Inc. from December 1999 to July 2001.

Michael L. Jines has served as our Senior Vice President, General Counsel and Corporate Secretary since May 2003. He was our Deputy General Counsel and Senior Vice President and General Counsel, Wholesale Group from March 2002 to May 2003. Previously, Mr. Jines served as Deputy General Counsel of CenterPoint and Senior Vice President and General Counsel of its Wholesale Group from 1999 until our separation from it.

Suzanne L. Kupiec has served as our Senior Vice President, Risk and Structuring since January 2004. She was our Vice President and Chief Risk and Corporate Compliance Officer from June 2003 to January 2004. Before joining us, Ms. Kupiec was a partner at Ernst & Young LLP, where she led its Energy Trading and Risk Management Practice serving both audit and advisory service clients.

Karen D. Taylor has served as our Senior Vice President, Human Resources since December 2003. In November 2005, she was appointed as our Chief Diversity Officer. Ms. Taylor was Vice President, Human Resources from February 2003 to December 2003 and Vice President, Administration, Wholesale Group from October 1998 to February 2003.

Thomas C. Livengood has served as our Senior Vice President and Controller since May 2005. He was Vice President and Controller from August 2002 to May 2005. From 1996 to August 2002, Mr. Livengood served as Executive Vice President and Chief Financial Officer of Carriage Services, Inc., a consumer services company.

Available Information

Our principal offices are at 1000 Main, Houston, Texas 77002 (713-497-7000). You can find on our website (http://www.reliant.com):

Our corporate governance guidelines and board committee charters;

As soon as reasonably practicable after they are filed or furnished to the SEC, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to these reports; and

Our business ethics policy.

You can request a free copy of these documents by contacting our investor relations department. In addition, these materials are available on the SEC's website at (http://www.sec.gov) or at its public reference room: 100 F Street, NE, Room 1580, Washington, D.C. 20549 (1-800-SEC-0330).

Certifications

We will timely provide the annual certification of our Chief Executive Officer to the New York Stock Exchange. We filed last year's certification in July 2005. In addition, our Chief Executive Officer and Chief Financial Officer each have signed and filed the certifications under Section 302 of the Sarbanes-Oxley Act of 2002 with this Form 10-K.

Item 1A. ***Risk Factors*.**

Risks Related to the Retail and Wholesale Energy Industries

The financial results of our wholesale and retail energy segments are subject to market risks beyond our control.

Our results of operations, financial condition and cash flows are significantly impacted by the prevailing demand and market prices for electricity, purchased power, fuel and emission allowances over which we have no control. Market prices can fluctuate dramatically in response to many factors, including weather conditions; changes in the prices of related commodities; changes in law and regulation; regulatory intervention (including the imposition of price limitations, bidding rules or similar mechanisms); market illiquidity; transmission constraints; environmental limitations; generation unit outages; fuel supply issues; and other events.

The wholesale and retail electricity markets in which we operate are relatively immature markets that are characterized by elements of both deregulated and regulated markets.

The introduction of competition into the United States electricity market is a relatively recent development. As a result, the market is characterized by elements of both a regulated electricity market and a deregulated electricity market. Consequently, our ability to set rates at market prices may be constrained by regulatory restrictions or possible regulatory or political intervention. In many instances, the regulatory structures governing these markets are still evolving, creating gaps in the regulatory framework and associated uncertainty. The new competitive market has attracted a number of new participants. Many of these companies are larger than us and possess stronger balance sheets. The emergence of aggressive competitors may put downward pressure on our retail margins and sales volumes over time. Other competitors are smaller, less well-capitalized entities that may default on their obligations to the market. These defaults may impose costs and burdens on the remaining market participants such as us. As an emerging market, a significant potential for industry consolidation exists as companies seek to expand and grow their operations, which may lead to stronger, more well-capitalized competitors in the industry.

Our operations are subject to extensive regulations. Changes in these regulations could adversely affect the cost, manner or feasibility of conducting our business.

We operate in a regulatory environment that is undergoing significant changes as a result of varying restructuring initiatives at both state and federal levels. We cannot predict the future direction of these initiatives or the ultimate effect that this changing regulatory environment will have on our business. Moreover, existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to our facilities or our commercial activities. Such future changes in laws and regulations may have an adverse effect on business. See "Business Regulation" in Item 1 of this Form 10-K.

We depend on facilities and systems that we do not own or control for our fuel and fuel supply and to deliver electricity to and bill our customers. Any disruption in these facilities or systems could have an adverse effect on our business.

We depend on (a) fuel sources and fuel supply facilities owned and operated by third parties to supply our generation plants and (b) power transmission, distribution facilities and metering systems owned and operated by third parties to deliver electricity to our customers and provide energy usage data. If these facilities or systems, over which we have no control, fail, we may be unable to generate and/or deliver electricity. In addition, inaccurate or untimely information from third parties could hinder our ability to bill customers and collect amounts owed.

The operation of generation facilities involves significant risks that could interrupt operations and increase our costs.

Ownership of generation assets exposes us to risks relating to the breakdown of equipment or processes, fuel supply or transportation interruptions, shortages of equipment, material and labor, operational restrictions resulting from environmental limitations and governmental interventions, as well as other operational risks. In addition, many of our facilities are old and require significant maintenance expenditures. We are party to collective bargaining agreements with labor unions at several of our plants. If (a) our workers were to engage in a strike, work stoppage or other slowdown, (b) other employees were to become unionized or (c) the terms and conditions in future labor agreements were renegotiated, we could experience a significant disruption in our operations and higher ongoing labor costs. Similarly, we have an aging workforce at a number of our plants creating potential knowledge and expertise gaps as those workers retire. If we are unable to secure fuel, we will not be able to run our generation units. If a generation unit fails, we may have to purchase replacement power from third parties at higher prices. We have insurance, subject to limits and deductibles, covering some types of physical damage and business interruption related to our generation units. However, this insurance may not always be available on commercially reasonable terms. In addition, there is no assurance that (a) insurance proceeds will be sufficient to cover all losses, (b) insurance payments will be timely made or (c) the policies themselves will be free of substantial deductibles.

Our business operations expose us to the risk of loss if third parties fail to perform their contractual obligations.

We may incur losses if third parties default on their obligations to pay us money; buy or sell electricity, fuel, emission allowances and other commodities; or provide us with fuel transportation services, power transmission or distribution services. For additional information about third party default risk, including our efforts to mitigate against this risk, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Risk" in Item 7 of this Form 10-K and note 2(e) to our consolidated financial statements.

We have a substantial coal- and oil-fired generation portfolio that poses environmental issues. Our costs of compliance with environmental laws are significant and can affect our future financial results.

Our wholesale energy segment is subject to extensive and evolving environmental regulations, particularly our coal- and oil-fired generation units. We incur significant costs in complying with these regulations and, if we fail to comply, could incur significant penalties. In addition, failure to comply with environmental requirements could require us to shut down or reduce production on our generation units or create liability exposure. New environmental laws or regulations may be adopted that would further constrain our operations or increase our environmental compliance costs. We also may be responsible for the environmental liabilities associated with generation units even if a prior owner caused the liabilities. We concluded that since our generating assets dispatch based on market prices, we should maintain an emission allowances inventory that corresponds with forward power sales. We plan to sell some excess emission allowances inventory if the price is equal to or above our fundamental view. To the extent allowances are required in the future to operate our facilities, such allowances may be unavailable or only available at costs exceeding our sales price. See "Business Environmental Matters" in Item 1 of this Form 10-K and note 12(b) to our consolidated financial statements.

Failure to obtain or maintain any required permits or approvals could prevent or limit us from operating our business.

To operate our generating units and retail electric business, we must obtain and maintain various permits, approvals and certificates from governmental agencies. In some jurisdictions, we must also meet minimum requirements for customer service and comply with local consumer protection and other laws. Our failure to obtain or maintain any necessary governmental permits or to satisfy these legal requirements, including environmental compliance provisions, could limit our ability to operate our business or create liability exposure.

Significant events beyond our control, such as hurricanes and other weather-related problems or acts of terrorism, could have a material adverse effect on our businesses.

The uncertainty associated with events beyond our control, such as significant weather events and the risk of future terrorist activity, may affect our results of operations and financial condition in unpredictable ways. These events could result in adverse changes in the insurance markets and disruptions of power and fuel markets. In addition, terrorist actions could damage or shut down our generation facilities or the fuel and fuel supply facilities or the power transmission and distribution facilities upon which our generation and retail businesses are dependent. These events could also adversely affect the United States economy, create instability in the financial markets and, as a result, have an adverse effect on our ability to access capital on terms and conditions acceptable to us.

Special Risks Relating to Our Texas Retail Operations

We depend on third parties to provide electricity to supply our Texas retail customers.

We own a very limited amount of generation capacity in Texas, which is insufficient to supply the electricity requirements of our Texas retail operations. We purchase substantially all of our Texas supply requirements from third parties. As a result, our financial performance depends on our ability to obtain adequate supplies of electric generation from third parties at prices below the prices we charge our customers.

Initiatives undertaken by the PUCT may negatively impact the wholesale cost of power.

The PUCT is expected to propose a new rule on resource adequacy and market power in the ERCOT Region. In this rule, the PUCT is considering an increase to the current price cap applicable

to generation bids into the ERCOT energy market, elimination of current market power mitigation measures and adoption of new market power guidelines. It is expected that these rules will be implemented sometime after the summer of 2006. If market power abuses are not adequately monitored and mitigated, these rules may have the impact of increasing the wholesale cost of power, which could adversely impact our gross margins in the Texas retail market.

The financial performance of our Texas retail electric operations depends on the amount of gross margin, or headroom, available in the "price-to-beat" tariff.

Our retail energy segment derives a significant portion of its revenue from sales to "price-to-beat" customers. The "price-to-beat" includes a component (fuel factor) that, subject to PUCT approval, can be adjusted to reflect changes in the market price of natural gas and purchased power costs. Under PUCT rules, we can request this adjustment twice a year. However, the PUCT or government officials may seek to (a) limit these adjustments in periods of concern over price levels or (b) change the existing rules for adjusting the "price-to-beat" rates.

The price of natural gas embedded in power supply purchases associated with our "price-to-beat" energy commitments can be different than that reflected in the fuel factor due to:

- varying supply procurement strategies used and the timing of entering into related contracts;
- subsequent changes in the overall price of natural gas;
- daily, monthly or seasonal fluctuations in the price of natural gas relative to the 12-month forward prices;
- changes in market heat rate (i.e., the relationship between power and natural gas prices);
- timing of prospective fuel factor adjustments; and
- other factors.

Our earnings could be adversely affected in any period in which our power supply costs rise at a greater rate than our "price-to-beat" fuel factor.

The declines we have experienced in our Houston retail gross margins may continue or accelerate.

In recent years, we have experienced significant declines in our gross margins in the Houston retail market. This trend could continue and be exacerbated by regulatory intervention. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Business Overview Factors Affecting Future Performance."

We may lose further market share in the Houston retail electricity market, which is a significant contributor of income to our consolidated results.

In recent years, we have experienced declines in our share of the Houston retail electricity market, which represents approximately 75% of our customer base. This trend could continue if competition increases. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Business Overview Factors Affecting Future Performance."

Our ability to set rates at market prices in Texas may be constrained by new legislative or regulatory restrictions.

The PUCT is evaluating the retail electric service provided after January 2007 by incumbent providers, such as us, to customers who have not selected a non "price-to-beat" product since the Texas retail electricity market opened to competition. In addition, the Texas Legislature is studying the effects of competition in the Texas retail electricity market. New legislation or rules governing the retail

electric prices we are allowed to charge after January 2007 could have an adverse effect on our financial condition, results of operations and cash flows.

We depend on the ERCOT ISO to communicate operating and system information in a timely and accurate manner. Corrections to prior estimated billing and other information can have an impact on our future reported financial results.

The ERCOT ISO communicates information relating to a customer's choice of retail electric provider and other data needed for servicing of customer accounts to utilities and retail electric providers. Any failure to perform these tasks will result in delays and other problems in enrolling, switching and billing customers. The ERCOT ISO is also responsible for settling all electricity supply volumes in the ERCOT Region. Information that is not accurate or timely may result in incorrect estimates of our settled volumes and supply costs that would need to be corrected when such information is received. See "Management's Discussion and Analysis of Financial Condition and Results of Operations New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates Critical Accounting Estimates" in Item 7 of this Form 10-K.

We could be liable for a share of the payment defaults of other retail electric providers within the ERCOT market.

If a retail electric provider defaults on its payment obligations to ERCOT, we, together with other ERCOT market participants, are liable for a portion of the defaulted amount based on our respective share of the total load. As of December 31, 2005, we accounted for approximately 20% of the total ERCOT load.

Risks Related to Our Company

Our borrowing levels and debt service obligations may adversely affect our business.

As of December 31, 2005, we had total debt from continuing operations of $5.1 billion:

- We must dedicate a substantial portion of our cash flows to pay debt service requirements, which reduces the amount of cash available for other business purposes;

- The covenants in our debt agreements restrict our ability to, among other things, (a) obtain additional financing, (b) make investments or acquisitions, (c) create additional liens on our assets and (d) take other actions to react to changes in our business;

- If we do not comply with the payment and other material covenants, including the financial ratios, under our debt agreements, our debt holders could require us to repay our debt immediately and, in the case of our revolving credit facilities and receivables facility, terminate their commitment to lend us money;

- So long as our debt remains at current levels, and substantially all our assets are pledged to secure repayment of our debt, we are unlikely to obtain an investment grade credit rating;

- Our debt levels and credit ratings may affect the evaluation of our creditworthiness by customers, which could put us at a competitive disadvantage to competitors with less debt;

- We have to post collateral with substantially all of our commercial counterparties and levels of our collateral postings are impacted by changes in commodity prices. A significant change in commodity prices could significantly increase our collateral posting obligations and require us to seek additional sources of liquidity, including additional debt; and

- We may be more vulnerable to adverse economic and industry conditions, including changes in short-term interest rates.

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Although we have taken steps to achieve greater financial flexibility, there is no assurance that we will be successful in achieving this goal.

In February 2004, we announced a goal of achieving, by the end of 2006, an adjusted net debt-to-adjusted EBITDA ratio of 3.0. Although we have taken steps to repay debt and implement other measures intended to improve our financial flexibility, we do not believe that we will achieve this goal in 2006. Even if we achieve our goal, or otherwise obtain credit metrics similar to those held by entities traditionally assigned investment grade credit ratings, there is no assurance credit rating agencies will improve our credit ratings.

Because of our debt levels and the capital-intensive nature of our business, we are vulnerable to reductions in our cash flows or liquidity.

If we were unable to generate sufficient cash flows, access funds from operations or raise cash from other sources, we would not be able to meet our debt service, collateral postings and other obligations. This situation could result from adverse developments in the energy, fuel or capital markets, a disruption in our operations or those of third parties or other events adversely affecting our cash flows and financial performance. We could experience reductions in liquidity if changes in commodity prices trigger our contractual obligations to pledge additional collateral under commodity contracts. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources" in Item 7 of this Form 10-K.

Our hedging and other risk management activities may not work as planned.

Our hedges may not be effective as a result of basis price differences, transmission issues, price correlation, volume variations or other factors. See "Quantitative and Qualitative Disclosures about Non-Trading and Trading Activities and Related Market Risks" in Item 7A of this Form 10-K.

Changes in the wholesale energy market or sales of generation assets could result in impairments.

If our outlook for the wholesale energy market changes negatively, or if our ongoing evaluation of our wholesale energy segment results in decisions to mothball, retire or dispose of generation assets, we could have impairment charges related to goodwill or our fixed assets. See notes 2(h) and 4 to our consolidated financial statements.

Lawsuits and regulatory proceedings could adversely affect our business.

From time to time, we are named as a party to lawsuits and regulatory proceedings. Litigation can involve complex factual and legal questions and its outcome is uncertain. Any claim that is successfully asserted against us could result in significant damage claims and other losses. Even if we were to prevail, any litigation could be costly and time-consuming and would divert the attention of our management and key personnel from our business operations, which could adversely affect our financial condition, results of operations or cash flows. See notes 12 and 13 to our consolidated financial statements.

We have entered into outsourcing arrangements with third party service providers. In addition, our retail and other commercial operations are highly dependent on computer and other operating systems, including telecommunications systems. Any interruptions in these arrangements or systems could significantly disrupt our business operations.

In recent years, we have entered into outsourcing arrangements, such as information technology production software, infrastructure and development and certain functions within customer operations, with third party service providers. If these service providers do not perform their obligations, we may incur significant costs and experience interruptions in our business operations in connection with

switching to other service providers or assuming these obligations ourselves. We are also highly dependent on our specialized computer and communications systems, the operation of which could be interrupted by fire, flood, power loss, computer viruses and similar disruptions. Although we have some backup systems and disaster recovery plans, there is no guarantee that these systems and plans will be effective.

If we acquire or develop additional generation assets, or dispose of existing generation assets, we may incur additional costs and risks.

Subject to restrictions in our debt agreements and available capital resources, we may seek to purchase or develop additional generation units or dispose of existing generation units. There is no assurance that our efforts to identify and acquire additional generation units or to dispose of existing generation assets will be successful. In the sale of generation units, we may be required to indemnify a purchaser against certain liabilities. To finance future acquisitions, we may be required to issue additional equity securities or incur additional debt.

Other Risks

For other company risks, see "Business" in Item 1 and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this Form 10-K.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

Our principal executive offices are leased through 2018, subject to two five-year renewal options. Our principal generation facilities are described under "Business Wholesale Energy" in Item 1 of this Form 10-K. We believe that our properties are adequate for our present needs. We have satisfactory title to our owned facilities, subject to exceptions, which, in our opinion, would not have a material adverse effect on the use or value of the facilities.

Item 3. ***Legal Proceedings.***

For a description of our material pending legal and regulatory proceedings and settlements, see notes 12 and 13 to our consolidated financial statements.

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

None.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Our common stock trades on the New York Stock Exchange under the ticker symbol "RRI." On March 1, 2006, we had 41,372 stockholders of record.

The closing price of our common stock on December 31, 2005 was $10.32.

	Market Price	
	High	**Low**
2005:		
First Quarter	$ 13.75	$ 10.97
Second Quarter	$ 13.00	$ 9.70
Third Quarter	$ 15.52	$ 12.20
Fourth Quarter	$ 15.65	$ 8.65
2004:		
First Quarter	$ 8.43	$ 6.61
Second Quarter	$ 10.97	$ 7.75
Third Quarter	$ 11.60	$ 8.81
Fourth Quarter	$ 13.94	$ 9.40

We have never paid dividends. Our debt agreements restrict the payment of dividends. See note 6 to our consolidated financial statements.

Sales of Unregistered Securities. During the fourth quarter of 2005, we issued 61,996 shares of unregistered common stock for warrants and 140,227 shares of unregistered common stock for $713,755 in cash pursuant to warrant exercises under an exemption pursuant to Section 4(2) of the Securities Act of 1933, as amended.

Item 6. *Selected Financial Data.*

	2005 (1)(2)(3)	2004 (1)(3)(4)(7)	2003 (1)(3)(4)(5)(6)(7)	2002 (1)(4)(7)(8)(9)(10)	2001 (1)
			(in millions)		
Statements of Operations Data:					
Revenues	$ 9,712	$ 8,098	$ 10,097	$ 10,230	$ 5,739
Operating income (loss)	(321)	(13)	(476)	249	701
Income (loss) from continuing operations	(441)	(276)	(916)	29	461
Cumulative effect of accounting changes, net of tax	(1)	7	(24)	(234)	3
Net income (loss)	(331)	(29)	(1,342)	(560)	563

	2005 (1)(2)	2004 (1)(7)	2003 (1)(4)(5)(7)	2002 (1)(4)(7)(8)(9)(10)	2001 (1)
Diluted Earnings (Loss) per Share:					
Income (loss) from continuing operations	$ (1.46)	$ (0.93)	$ (3.12)	$ 0.10	$ 1.66

	2005 (1)	2004 (1)(7)	2003 (1)	2002 (1)(8)(10)	2001 (1)
			(in millions)		
Statements of Cash Flow Data:					
Cash flows from operating activities	$ (917)	$ 106	$ 994	$ 234	$ (9)
Cash flows from investing activities	306	900	917	(3,204)	(981)
Cash flows from financing activities	594	(1,047)	(2,889)	3,985	1,000

	December 31,				
	2005 (1)(11)	2004 (1)	2003 (1)(5)(6)	2002 (1)(8)(9)(10)	2001 (1)
			(in millions)		
Balance Sheet Data:					
Net margin deposits on energy trading and hedging activities	$ 1,700	$ 487	$ 36	$ 259	$ 69
Total assets	13,569	12,194	13,297	17,219	11,726
Current portion of long-term debt and short-term borrowings	789	619	129	518	94
Long-term debt to third parties	4,317	3,939	4,276	4,555	295
Stockholders' equity	3,864	4,386	4,372	5,653	5,984

(1) Our results of operations include Orion Power since its acquisition in February 2002. We sold or transferred the following operations, which have been classified as discontinued operations: Desert Basin, European energy, Orion Power's hydropower plants, Liberty, Ceredo and Orion Power's New York plants. We sold the following operations, which are included in continuing operations: REMA hydropower plants in April 2005, landfill-gas fueled power plants in July 2005 and our El Dorado investment in July 2005. See notes 19 and 20 to our consolidated financial statements.

(2) During 2005, we recorded charges of $359 million relating to various settlements associated with the western energy crisis. See note 13(a) to our consolidated financial statements.

(3) Effective October 1, 2003, we adopted EITF No. 03-11 and began prospectively reporting the settlement of sales and purchases of fuel and purchased power related to our non-trading commodity derivative activities that were not physically delivered on a net basis in our results of operations in the same line as the item hedged. This resulted in decreased revenues and decreased purchased power, fuel and cost of gas sold of $4.2 billion, $2.4 billion and $834 million for 2005, 2004 and the fourth quarter of 2003, respectively. We did not reclassify amounts for periods prior to October 1, 2003. See note 2(d) to our consolidated financial statements.

(4) We adopted EITF No. 02-03 effective January 1, 2003, which affected our accounting for electricity sales to large commercial, industrial and governmental/institutional customers under executed contracts and our accounting for trading and hedging activities. It also impacted these contracts executed after October 25, 2002 in 2002. See note 2(c) to our consolidated financial statements.

(5) During 2003, we recorded a goodwill impairment charge of $985 million. See note 4 to our consolidated financial statements.

(6) We adopted FASB Interpretation No. 46 on January 1, 2003, as it related to our variable interests in three power generation projects that were being constructed by off-balance sheet entities, which pursuant to this guidance required consolidation upon adoption. As a result, we increased our property,

plant and equipment and our secured debt obligations by $1.3 billion.

(7) During 2004, 2003 and 2002, we recorded charges of $2 million, $47 million and $128 million, respectively, relating to a payment made to CenterPoint in 2004 of $177 million. See note 13(d) to our consolidated financial statements.

(8) The retail electric energy market in Texas opened to full competition beginning January 1, 2002.

(9) During 2002, we recorded an impairment of our European energy segment's goodwill of $234 million, net of tax, as a cumulative effect of accounting change.

(10) Effective September 30, 2002, we separated from CenterPoint and prior to that date our financial position and results of operations may not reflect as if we had operated as a separate, stand-alone entity.

(11) See note 12 to our consolidated financial statements for discussion of our contingencies.

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

Business Overview

Strategies and Objectives

Our objective is to be a leader in restructuring and consolidating the competitive electricity industry. As part of this objective, we focus on the competitive segments of the retail and wholesale electricity markets.

Retail Energy. Our retail energy segment is a low capital investment electricity resale business with relatively stable earnings. The keys to success in the retail energy segment are the volume of megawatt hours we sell to customers and the unit margins received from the customers. We earn a margin by selling electricity to end-use customers and securing a margin by simultaneously acquiring supply. Short-term earnings in this business are impacted by local weather patterns and the competitive tactics of other retailers in the market. The longer-term earnings drivers of the business are the level of competitive intensity and our ability to retain and grow market share by having a strong brand and excellent customer service.

During 2006, we expect to complete the successful transition to a fully competitive retail market in Texas, which we expect will result in higher margin levels in 2007. During 2006, we will strive to switch a significant portion of our "price-to-beat" customers to longer-term and innovative new products to maintain our market share in Houston.

Wholesale Energy. Our wholesale energy segment is a capital-intensive, cyclical business whose earnings are significantly impacted by the level of natural gas prices and spark spreads, among other factors. The key earnings drivers are the amount of electricity we generate and the margin we earn for each unit of electricity sold. We cannot control those factors that have the most significant impact on our earnings levels. The factor that we have the most control over is the percentage of time that our generating plants are available to run when it is economic for them to do so. Short-term earnings in our wholesale business are impacted by weather and commodity price levels. Longer-term earnings are driven by the level of commodity prices and regional supply and demand fundamentals.

In February 2006, we completed an evaluation of our wholesale energy segment's hedging strategy and use of capital. We concluded that the benefits we received from hedging were not sufficient to justify our hedging program. As a result, we decided to substantially reduce new hedges of our generation on a prospective basis.

Corporate. A key priority for 2006 is to substantially reduce the amount of capital committed to collateral requirements. We will achieve this primarily through transitioning to an open wholesale model. In addition, we will strive to enter a credit-enhanced structure for the procurement of retail supply. The open model provides a meaningful representation of the earnings power of the company as it excludes the impact of historical wholesale hedging activity, gains on the sales of emission allowances and gains or losses on the sales of assets and equity method investments.

We have made significant progress in restructuring our business processes to be efficient, cost-sensitive and scalable in order to position ourselves to take advantage of future growth opportunities. As of December 31, 2005, we realized $315 million of our previously announced $340 million in cost reductions. While the initial program is substantially complete, we will continue to focus on increasing our operating efficiencies.

In 2005, we completed our planned asset divestiture program to reduce our debt levels. Total proceeds from the sales (from 2003 through 2005) were $3.7 billion (including the $979 million received in February 2006 for the New York plants). We will continue to focus on improving our financial flexibility through enhancing our earnings.

We have made a commitment to provide greater insight into the key earnings drivers of our business. In early 2006, we introduced enhanced financial disclosures that allow for a robust analysis of the impacts various factors have on our earnings.

We believe that stockholder value is enhanced through the development of a highly motivated and customer-focused work force. We have focused on a series of actions designed to build a "great company to work for," including (a) communicating openly with our employees, (b) fostering company pride among our employees, (c) providing a satisfying and safe work environment, (d) recognizing and rewarding employee contributions and capabilities and (e) enrolling our employees to be collaborative leaders committed to our future.

Our ability to achieve these strategic objectives and executing these actions are subject to a number of factors, some of which we may not be able to control. See "Cautionary Statement Regarding Forward-Looking Information" and "Risk Factors" in Item 1A of this Form 10-K.

Factors Affecting Future Performance

Our retail energy segment has been the largest contributor of income to our consolidated results for the last several years. Beginning in 2006, we expect that our wholesale energy segment will contribute more to our consolidated results for the reasons outlined below.

Retail Energy. Key earnings drivers for our retail energy segment include the margins received from sales to our retail customers and the volume of megawatt hours sold to our customers.

During 2005, in response to significant increases in natural gas prices, public policy concerns and to help mitigate the impact of higher natural gas prices on our customers, we agreed to phase-in our "price-to-beat" rate increase by offering discounts to existing residential "price-to-beat" customers. We also entered into hedges equal to the expected load for those customers. We anticipate that our retail energy segment's gross margin will be negatively impacted by approximately $90 million during the first quarter of 2006, based on estimated supply costs and revenue rates. In addition, we have estimated that gross margin will be negatively impacted by up to $70 million during 2006 because the revenue increase from our "price-to-beat" rate will be less than our expected increase in supply costs. However, each of these factors will ultimately depend on our actual revenue rates from our customers and our total supply costs.

During 2006, we expect that our retail energy segment will continue to experience a loss of "price-to-beat" customers due to these customers switching to other suppliers and moving to non "price-to-beat" products. However, we intend to offset this impact by adding new customers. Further, the potential for increased energy conservation, as monthly rates will be higher than in the summer of 2005, could reduce the average usage per customer. Also, with higher bills, switching rates could increase if competitive activity increases.

We do not believe that the current retail margins in the ERCOT Region are indicative of retail margins longer term. In 2007 and 2008, we believe that retail margins will return to more compensatory levels that would be associated with the transition to a fully competitive retail market in the ERCOT Region.

For our retail energy segment, we will continue to focus our supply procurement strategy on (a) matching our supply costs with our fixed price sales commitments and (b) procuring physical supply to manage operational issues and within market liquidity constraints.

Wholesale Energy. Key earnings drivers for the wholesale energy segment include: (a) the number of hours our generation is potentially economic to operate; (b) the commercial capacity factor of our power plants; (c) unit margins received from our power plants; (d) other margins received, from among other things, capacity payments and ancillary services; and (e) the settlement of our historical hedges, which is expected to be negative.

In 2006, we expect that the results of operations for our wholesale energy segment will improve based on increased demand in key wholesale markets, including California and the PJM Market, increased availability of coal-fueled generation plants and improved margins. To achieve this, we intend to perform additional maintenance on our coal-fueled generation plants and improve the operating efficiency of this business segment.

As stated above, in February 2006, we concluded that the benefits we received from hedging were not sufficient to justify our historical hedging program. As a result, we decided to substantially reduce new hedges of our generation. We intend to continue entering into selective hedges, including originated transactions, based on (a) our assessment of market fundamentals to increase the return from our generation assets and (b) operational and market limitations requiring us to enter into fuel, capacity and emissions transactions to manage our generation assets. We believe that this new strategy will significantly reduce our wholesale energy segment's use of capital; however, our earnings will be subject to volatility based on market price changes. Existing positions will be closed as economically feasible or in accordance with their terms.

Liquidity. Net cash flow provided by operations for 2005 was negatively impacted by increases in margin posting requirements resulting from significant changes in commodity prices. We anticipate reducing collateral postings (including cash and letters of credit) by approximately $1 billion in 2006, which will result in higher operating cash flow.

Consolidated Results of Operations

Summary by Segment

Retail Energy Segment. Our retail energy segment's contribution margin was $342 million during 2005 compared to $377 million during 2004. The $35 million decrease in contribution margin was primarily due to the decrease in gross margin. Excluding unrealized gains/losses, the gross margin decrease of $249 million was primarily due to lower hedge benefit related to "price-to-beat" customers. Lower volumes and reduced margins related to "price-to-beat" customers and higher other supply costs also contributed to lower retail gross margin. This decrease in gross margin was partially offset by a net change in unrealized gains/losses on energy derivatives of $203 million. Selling and marketing expense increased $13 million. However, operation and maintenance expense decreased $32 million primarily due to decreased salaries, benefits and severance expense.

Our retail energy segment's contribution margin was $377 million during 2004 compared to $839 million during 2003. The $462 million decrease in contribution margin was primarily due to the net change in unrealized gains/losses on energy derivatives of $265 million. In addition, gross margin, excluding unrealized gains/losses, decreased $259 million due primarily to lower hedge benefit related to "price-to-beat" customers. Lower volumes and reduced margins related to "price-to-beat" customers and higher other supply costs also contributed to lower retail gross margin. Operation and maintenance expense decreased $29 million primarily due to decreased salaries and benefits expense.

Wholesale Energy Segment. Our wholesale energy segment's contribution margin was $110 million during 2005 compared to $247 million during 2004. The $137 million decrease in contribution margin was primarily due to $171 million change in unrealized gains/losses on energy derivatives. This decrease was partially offset by a $22 million increase in gross margin, excluding unrealized gains/losses on energy derivatives.

Our wholesale energy segment's contribution margin was $247 million during 2004 compared to $381 million during 2003. The $134 million decrease in contribution margin was primarily due to a $215 million decrease in gross margin, excluding unrealized gains/losses on energy derivatives, primarily due to (a) $118 million decrease in the PJM region and (b) $106 million change in our accounts receivable, refund obligation and credit reserves for energy sales in California. This decrease was partially offset by an $89 million change in unrealized gains/losses on energy derivatives.

Unrealized Gains/Losses on Energy Derivatives. We use derivative instruments to manage operational or market constraints, to increase the return on our generation assets and to execute our retail energy segment's supply procurement strategy. Some derivative instruments receive mark-to-market accounting treatment, which requires us to record gains/losses related to future periods based on current changes in forward commodity prices. We refer to these gains and losses prior to settlement, as well as ineffectiveness on cash flow hedges (see note 5 to our consolidated financial statements), as "unrealized gains/losses on energy derivatives." In some cases, the related underlying transactions being hedged receive accrual accounting treatment, resulting in a mismatch of accounting treatments.

2005 Compared to 2004

Net Income (Loss). We reported $331 million consolidated net loss, or $1.09 loss per share, for 2005 compared to $29 million consolidated net loss, or $0.10 loss per share, for 2004. The change is (in millions):

Western states and Cornerstone settlements	$ (359)
Gain on sale of counterparty claim	(30)
Net unrealized gains/losses on energy derivatives	32
Retail energy gross margin, excluding unrealized gains/losses	(249)
Wholesale energy gross margin, excluding unrealized gains/losses	22
Operation and maintenance	45
Selling, general and administrative	33
Loss on sales of receivables	34
Gains on sales of assets and emission allowances, net	148 [(1)]
Depreciation and amortization	7
Losses from investments, net	(32)
Income (loss) of equity investments, net	35
Interest expense	19
Interest income	(12)
Other, net	5
Income taxes	137
Loss from continuing operations	(165)
Discontinued operations	(129)
Net change before cumulative effect of accounting changes	(294)
Cumulative effect of accounting change in 2004, net of tax	(7)
Cumulative effect of accounting change in 2005, net of tax	(1)
Net change	$ (302)

(1) Of this amount, $141 million relates to sales of emission allowances. See note 19 to our consolidated financial statements.

Retail Energy Gross Margins. Our retail energy gross margins decreased to $683 million during 2005 compared to $729 million for 2004. The decrease is (in millions):

Net unrealized gains/losses on energy derivatives	$ 203 [(1)]
Higher purchased power costs and volume impacts partially offset by higher revenue rates	(249)[(2)]
Net decrease in margin	$ (46)

(1) Increase primarily due to (a) $198 million gain due to unrealized losses recognized in prior periods being realized during 2005 as compared to 2004, (b) $75 million gain due to cash flow hedge ineffectiveness during 2005 as compared to 2004 and (c) $51 million gain due to certain contracts failing to meet the normal purchases scope exception. These increases were partially offset by (a) $122 million loss due to the impact of natural gas and power prices on our portfolio of derivatives held during 2005 as compared to 2004 for purposes of economically hedging our supply and (b) $7 million loss due to the reversal of previously recognized unrealized gains on positions entered into during 2005.

(2) Decrease primarily due to (a) lower hedge benefit from "price-to-beat" customers, (b) reduced volumes sold at "price-to-beat" rates to small business and residential customers, (c) increases in costs of transmission and distribution losses in ERCOT, (d) decrease of margins from "price-to-beat" customers and (e) increases in other supply costs. These decreases were partially offset by an increase in volumes sold at non "price-to-beat" rates.

Retail Energy Revenues.

	2005	2004	Change
		(in millions)	
Retail energy revenues from end-use retail customers:			
Texas:			
Residential and small business	$ 4,005	$ 3,531	$ 474 [(1)]
Large commercial, industrial and governmental/institutional	2,185	1,957	228 [(2)]
Outside of Texas:			
Commercial, industrial and governmental/institutional	404	204	200 [(3)]
Total	6,594	5,692	902
Retail energy revenues from resales of purchased power and other hedging activities	474	374	100 [(4)]
Market usage adjustments	(23)	(2)	(21)[(5)]
Total retail energy revenues	$ 7,045	$ 6,064	$ 981

(1) Increase primarily due to (a) increase in sales prices to customers due to increases in the price of natural gas and (b) increased non "price-to-beat" volumes due to increased customers. These increases were partially offset by lower volumes from "price-to-beat" customers due to fewer customers.

(2) Increase primarily due to fixed-price contracts renewed at higher rates due to higher prices of natural gas and variable-rate contracts, which are tied to the market price of natural gas. This increase was partially offset by decreased volumes.

(3) Increase primarily due to increased volumes due to market entry in Maryland and other PJM markets in 2004 and fixed-price contracts renewed at higher rates due to higher prices of natural gas and variable-rate contracts, which are tied to the market price of natural gas.

(4) Increase primarily due to our supply management activities in various markets within Texas.

(5) See note 2(c) to our consolidated financial statements.

Retail Energy Purchased Power.

	2005	2004	Change
		(in millions)	
Costs of purchased power	$ 6,301	$ 5,047	$ 1,254 [1]
Market usage adjustments	(8)	16	(24)[2]
Unrealized (gains) losses	69	272	(203)[3]
Total retail energy purchased power	$ 6,362	$ 5,335	$ 1,027

(1) Increase primarily due to (a) an increase in price of purchased power due to higher market prices of electricity primarily driven by higher natural gas prices, (b) less favorable hedging activity in 2005 compared to 2004 and (c) increases in costs of transmission and distribution losses in ERCOT. These increases were partially offset by a decrease in customer usage.

(2) See note 2(c) to our consolidated financial statements.

(3) See analysis of net unrealized gains/losses on energy derivatives in the gross margins discussion above.

Wholesale Energy Gross Margins. Our wholesale energy gross margins decreased to $656 million during 2005 compared to $805 million for 2004. The decrease is (in millions):

California energy sales receivables, refund and reserve changes	$ 12
Net unrealized gains/losses on energy derivatives	(171)[1]
Adjustment to October 2003 FERC settlement recorded in September 2004	12
PJM region	(56)[2]
East gas transport region	(27)[3]
West gas transport region	(19)[4]
Southeast region	12 [5]
West region	15 [6]
MISO region	79 [7]
Other, net	(6)
Net decrease in margin	$ (149)

(1) Decrease primarily due to (a) $89 million higher unrealized losses in 2005 as compared to 2004 on positions entered to hedge the economics of our business operations which receive mark-to-market accounting treatment, (b) $80 million loss from de-designated hedge positions and (c) $15 million reversal of previously recognized unrealized gains resulting from the settlement of the positions during 2005. These decreases are partially offset by a $13 million gain due to changes in cash flow hedge ineffectiveness in 2005 as compared to 2004.

(2) Decrease primarily due to (a) lower realized margins due to unfavorable differences between prices received by our coal plants and settlement prices on our hedged power sales, (b) higher coal costs and (c) a change in the amortization of contractual rights and obligations. These decreases were partially offset by (a) the new Seward plant achieving commercial operation in October 2004 and (b) increased generation due to higher prices and lower plant outages.

(3) Decrease primarily due to (a) significant drop in natural gas prices during the fourth quarter of 2005, and the corresponding impact on market liquidity, resulting in losses on our gas supply and transportation positions, (b) settlement of gas storage hedges at losses while the anticipated withdrawal and

sale of natural gas inventory was deferred to the first quarter of 2006 due to more favorable economics and (c) lower of cost or market adjustment on gas inventory.

(4) Decrease primarily due to unfavorable spreads on gas transportation.

(5) Increase primarily due to higher generation at our dual fuel plants due to higher temperatures and disruption in the availability of natural gas plants due to the hurricanes during the third quarter of 2005. This increase is partially offset by lower margins from power purchase agreements.

(6) Increase primarily due to (a) higher margins from power purchase agreements and (b) the restart of Etiwanda units 4 and 3 in June and September 2004, respectively. These increases were partially offset by (a) lower ancillary revenues and margins and (b) lower generation driven by milder weather.

(7) Increase primarily due to (a) higher realized margins as 2004 obligations under a "provider of last resort" contract (which primarily ended during the fourth quarter of 2004) were priced lower than 2005 market prices and (b) increased generation driven by (i) a decrease in outages at the Avon Lake plant and (ii) higher prices. These increases were partially offset by higher coal costs.

Wholesale Energy Revenues.

	2005	2004	Change
		(in millions)	
Wholesale energy third-party revenues	$ 2,879	$ 2,057	$ 822 [1]
Wholesale energy intersegment revenues	625	349	276 [2]
Unrealized losses	(218)	(32)	(186)[3]
Total wholesale energy revenues	$ 3,286	$ 2,374	$ 912

(1) Increase primarily due to (a) $248 million due to certain gas transactions, which prior to April 1, 2004, were recorded net as a part of the trading activity and are now recorded gross in revenues and fuel and cost of gas sold, (b) increase in natural gas prices and (c) increase in natural gas sales volumes. These increases were partially offset by a decrease in power sales prices and power sales volumes.

(2) Increase primarily due to higher volumes due to more retail energy segment sales in the PJM Market.

(3) See analysis of net unrealized gains/losses on energy derivatives in the gross margins discussion above.

Wholesale Energy Purchased Power, Fuel and Cost of Gas Sold.

	2005	2004	Change
		(in millions)	
Wholesale energy third-party costs	$ 2,725	$ 1,649	$ 1,076 [1]
Unrealized gains	(95)	(80)	(15)[2]
Total wholesale energy	$ 2,630	$ 1,569	$ 1,061

(1) Increase primarily due to (a) $254 million due to certain gas transactions, which prior to April 1, 2004, were recorded net as a part of the trading activity and are now recorded gross in revenues and fuel and cost of gas sold (see footnote (1) under "Wholesale Energy Revenues"), (b) higher prices of natural gas, oil and coal and (c) increased volumes of natural gas and coal purchased.

(2) See analysis of net unrealized gains/losses on energy derivatives in the gross margins discussion above.

Operation and Maintenance.

2005	2004	Change

	2005	2004	Change
		(in millions)	
Retail energy	$ 190	$ 222	$ (32)
Wholesale energy	544	560	(16)
Other operations	3		3
Consolidated	$ 737	$ 782	$ (45)

The decrease in our retail energy segment is (in millions):

Severance	$ (3)
Salaries and benefits	(28)
Other, net	(1)
Net decrease in expense	$ (32)

The decrease in our wholesale energy segment is (in millions):

Severance	$ (6)
Taxes other than income	(18)[1]
Salaries and benefits, excluding plant personnel	(7)
Termination of certain services to Texas Genco in May 2004	(7)
Planned power generation maintenance projects and outages	(6)
Unplanned power generation maintenance projects and outages	10
Bighorn plant and new Seward plant achieved commercial operation in February 2004 and October 2004, respectively	21
Other, net	(3)
Net decrease in expense	$ (16)

(1) Decrease primarily due to the resolution of tax contingencies.

Selling, General and Administrative.

Restructuring costs associated with lease on corporate headquarters	$ (13)
Severance	(13)
Settlement of shareholder class action lawsuits	8
Salaries and benefits[1]	(26)
Rents and utilities	(7)
Contract services and professional fees	(7)
Marketing	11
Bad debt expense	12
Other, net	2
Net decrease in expense	$ (33)

(1) Decrease primarily due to impact of decreased stock price on stock-based incentive plan expense.

Western States and Cornerstone Settlements. See note 13(a) to our consolidated financial statements.

Loss on Sales of Receivables. The decrease of $34 million is due to our ceasing to record sales of receivables as sales for accounting purposes due to the amendment of the facility in September 2004. See note 6 to our consolidated financial statements.

Gain on Sale of Counterparty Claim. See note 13(e) to our consolidated financial statements.

Gains on Sales of Assets and Emission Allowances, Net. See note 19 to our consolidated financial statements.

Depreciation and Amortization.

Equipment impairment charge in 2004 related to turbines and generators	$	(16)
Accelerated depreciation on Wayne facility in 2004 due to early retirement		(12)
Information system assets fully depreciated in 2004		(24)
Increase in amortization of emission allowances		13
Net accelerated depreciation on certain facilities due to early retirements		20
Bighorn plant and new Seward plant achieved commercial operation in February 2004 and October 2004, respectively		22
Other, net		(10)
Net decrease in expense	$	(7)

Income (Loss) of Equity Investments, Net. Income (loss) of equity investments, net changed by $35 million primarily due to a $25 million gain on sale of our El Dorado investment and an $8 million decrease in losses from El Dorado. See note 19 to our consolidated financial statements.

Other, Net. During 2005, other, net primarily represents a $23 million impairment of an investment. See note 18 to our consolidated financial statements.

Interest Expense.

Amortization of deferred financing costs	$	(63)
Financing fees expensed		(26)
Decrease in outstanding debt		3
Higher interest rates		23
Lower capitalized interest		46
Other, net		(2)
Net decrease in expense	$	(19)

Interest Income.

Receivables facility	$	(12)
Interest on California net receivables		(10)
Net margin deposits		10
Net decrease in income	$	(12)

Income Tax Expense (Benefit). During 2005 and 2004, our effective tax rate was 36% and 29%, respectively. See note 10 to our consolidated financial statements.

Discontinued Operations. See note 20 to our consolidated financial statements.

2004 Compared to 2003

Net Income (Loss). We reported $29 million consolidated net loss, or $0.10 loss per share, for 2004 compared to $1,342 million consolidated net loss, or $4.57 loss per share, for 2003. The change is (in millions):

Gain on sale of counterparty claim	$ 30
Net unrealized gains/losses on energy derivatives	(176)
Retail energy gross margin, excluding unrealized gains/losses	(259)
Wholesale energy gross margin, excluding unrealized gains/losses	(215)
Operation and maintenance	27
Selling, general and administrative	102
Loss on sales of receivables	3
Gains on sales of assets and emission allowances, net	17 [1]
Wholesale Energy goodwill impairment	985
Depreciation and amortization	(95)
Gains from investments, net	7
Loss of equity investments, net	(7)
Accrual for payment to CenterPoint	45
Interest expense	(11)
Other, net	(4)
Income taxes	191
Loss from continuing operations	640
Discontinued operations	642
Net change before cumulative effect of accounting changes	1,282
Cumulative effect of accounting change in 2003, net of tax	24
Cumulative effect of accounting change in 2004, net of tax	7
Net change	$ 1,313

(1) Of this amount, $19 million relates to sales of emission allowances. See note 19 to our consolidated financial statements.

Retail Energy Gross Margins. Our retail energy gross margins decreased to $729 million during 2004 compared to $1,253 million for 2003. The decrease is (in millions):

Net unrealized gains/losses on energy derivatives	$ (265)[1]
Gains recorded prior to 2003 realized/collected in current periods	45 [2]
Higher purchased power costs and volume impacts partially offset by higher revenue rates	(258)[3]
Change in market usage adjustments	(46)[4]
Net decrease in margin	$ (524)

(1) Decrease primarily due to unrealized losses on short natural gas positions recognized in 2004 as a result of higher natural gas prices.

(2) Increase due to the impact of EITF No. 02-03. See note 2(c) to our consolidated financial statements

(3)

Decrease primarily due to (a) reduced hedging benefit from "price-to-beat" customers realized in 2004 compared to 2003, (b) other increases in supply costs, (c) reduced volumes due to fewer "price-to-beat" small business and residential customers and (d) reduced usage from "price-to-beat" residential customers due to milder weather. These decreases were partially offset by an increased usage from our non "price-to-beat" customers primarily due to increased customers.

(4) See note 2(c) to our consolidated financial statements.

Retail Energy Revenues.

	2004	2003	Change
		(in millions)	
Retail energy revenues from end-use retail customers:			
Texas:			
Residential and small business	$ 3,531	$ 3,460	$ 71 [(1)]
Large commercial, industrial and governmental/institutional	1,957	1,526	431 [(2)]
Outside of Texas:			
Commercial, industrial and governmental/institutional	204	40	164 [(3)]
Total	5,692	5,026	666
Retail energy revenues from resales of purchased power and other hedging activities other hedging activities	374	688	(314)[(4)]
Market usage adjustments	(2)	31	(33)[(5)]
Unrealized losses		(16)	16 [(6)]
Total retail energy revenues	$ 6,064	$ 5,729	$ 335

(1) Increase primarily due to (a) increase in sales prices to customers due to increases in the price of natural gas and (b) increased non "price-to-beat" volumes due to increased customers. These increases were partially offset by lower volumes primarily due to (a) milder weather and (b) fewer "price-to-beat" customers.

(2) Increase primarily due to (a) increased volumes from additional customers and (b) fixed-price contracts renewed at higher rates due to higher prices of natural gas and variable-rate contracts, which are tied to the market price of natural gas.

(3) Increase due to entering parts of the PJM Market in August 2003 and throughout 2004.

(4) Decrease primarily due to $224 million due to the application of EITF No. 03-11 (see note 2(d) to our consolidated financial statements).

(5) See note 2(c) to our consolidated financial statements.

(6) See analysis of net unrealized gains/losses on energy derivatives in the gross margins discussion above.

Retail Energy Purchased Power.

	2004	2003	Change
		(in millions)	
Costs of purchased power	$ 5,047	$ 4,482	$ 565 [(1)]
Market usage adjustments	16	3	13 [(2)]
Unrealized (gains) losses	272	(9)	281 [(3)]
Total retail energy purchased power	$ 5,335	$ 4,476	$ 859

(1)

Increase primarily due to (a) increase in customer usage, (b) an increase in price of purchased power due to higher market prices of electricity primarily driven by higher natural gas prices and (c) reduced benefit in supply hedging.

(2)

See note 2(c) to our consolidated financial statements.

(3)

See analysis of net unrealized gains/losses on energy derivatives in the gross margins discussion above.

Wholesale Energy Gross Margins. Our wholesale energy gross margins decreased to $805 million during 2004 compared to $931 million for 2003. The decrease is (in millions):

California energy sales receivables, refund and reserve changes	$	(106)
Net unrealized gains/losses on energy derivatives		89 [1]
Adjustment to October 2003 FERC settlement recorded in September 2004		(12)
FERC settlement in October 2003		37
PJM region		(118)[2]
MISO region		(29)[3]
Margins associated with CenterPoint		(14)[4]
West region		33 [5]
Other, net		(6)
Net decrease in margin	$	(126)

(1) Increase primarily due to (a) $50 million increase in unrealized trading margins in 2004 as compared to 2003, (b) $15 million unrealized gain on positions primarily in the West region, (c) $18 million increase due to ineffectiveness in 2004 as compared to 2003 and (d) $10 million gain as a result of the change in market values on cash flow hedges de-designated in the West region in July 2004.

(2) Decrease primarily due to (a) increased fuel costs, (b) increased unplanned outages, (c) weaker market conditions due in part to milder weather and (d) the retirement of the old Seward plant in the fourth quarter of 2003 and Sayreville units 4 and 5 in February 2004. These decreases were partially offset by Hunterstown and new Seward, which achieved commercial operation in July 2003 and October 2004, respectively.

(3) Decrease primarily due to (a) increased purchased power and the operation of less efficient plants due to the unplanned outages in order to fulfill our contractual load obligations under a "provider of last resort" contract in the second quarter of 2004 and (b) lower volumes in the last half of 2004 as the demand under a "provider of last resort" contract declined due in part to milder weather.

(4) Decrease associated with reduction in billings to CenterPoint for engineering, technical and other support services provided to Texas Genco's facilities under a support agreement, which terminated in 2004.

(5) Increase due to (a) the Bighorn plant achieving commercial operation in February 2004 and entering into a power purchase agreement in June 2004, (b) the restart of Etiwanda units 4 and 3 in June and September 2004, respectively, and (c) increased generation to meet the needs of the Cal ISO.

Wholesale Energy Revenues.

	2004	2003	Change
		(in millions)	
Wholesale energy third-party revenues	$ 2,057	$ 4,406	$ (2,349)[1]
Wholesale energy intersegment revenues	349	225	124 [2]
Unrealized losses	(32)	(39)	7 [3]
Total wholesale energy revenues	$ 2,374	$ 4,592	$ (2,218)

(1) Decrease primarily due to (a) $1.4 billion due to the application of EITF No. 03-11 (see note 2(d) to our consolidated financial statements), (b) a decrease in power sales volumes primarily due to fewer resales of purchased power as a result of changes in our strategies for risk management and hedging activities in late 2002 and early 2003 and (c) a $106 million change in our accounts receivable, refund obligation and credit reserves for energy sales in California. These decreases were partially offset by (a) an increase in power prices due to increased natural gas and coal prices and (b) a $25 million net change to our FERC settlement obligation.

(2) Increase primarily due to higher power prices as a result of increased natural gas prices, partially offset by lower volumes.

(3) See analysis of net unrealized gains/losses on energy derivatives in the gross margins discussion above.

Wholesale Energy Purchased Power, Fuel and Cost of Gas Sold.

	2004	2003	Change
		(in millions)	
Wholesale energy third-party costs	$ 1,649	$ 3,659	$ (2,010)[(1)]
Unrealized (gains) losses	(80)	2	(82)[(2)]
Total wholesale energy	$ 1,569	$ 3,661	$ (2,092)

(1) Decrease primarily due to (a) $1.4 billion due to the application of EITF No. 03-11 (see note 2(d) to our consolidated financial statements) and (b) decreased purchased power volumes primarily due to changes in our strategies for risk management and hedging activities in late 2002 and early 2003. These decreases were partially offset by higher prices of natural gas, coal and purchased power.

(2) See analysis of net unrealized gains/losses on energy derivatives in the gross margins discussion above.

Operation and Maintenance.

	2004	2003	Change
		(in millions)	
Retail energy	$ 222	$ 251	$ (29)
Wholesale energy	560	558	2
Consolidated	$ 782	$ 809	$ (27)

The decrease in our retail energy segment is (in millions):

Severance	$ 4
Salaries and benefits	(27)
Other, net	(6)
Net decrease in expense	$ (29)

The increase in our wholesale energy segment is (in millions):

Four power generation facilities achieving commercial operation in late July 2003 (Hunterstown and Choctaw), February 2004 (Bighorn) and late October 2004 (new Seward)	$ 28
Planned power generation maintenance projects and outages	18
Unplanned power generation maintenance projects and outages	7
Termination of certain services to Texas Genco in May 2004	(11)
Retirement/mothball of power generation units	(17)
Salaries and benefits, excluding plant personnel	(34)
Other, net	11
Net increase in expense	$ 2

Selling, General and Administrative.

Commodity Futures Trading Commission settlement in November 2003	$ (18)
Severance costs	(16)[1]
Marketing	(16)
Contractor services and professional fees	(14)[2]
Legal costs	(13)
Bad debt expense	(11)
Taxes other than income taxes	(8)[3]
Salaries and benefits	(7)[4]
Restructuring costs associated with lease on corporate headquarters	13
Other, net	(12)
Net decrease in expense	$ (102)

(1) Decrease primarily due to executive severance costs in 2003, partially offset by restructuring severance costs in 2004.

(2) Decrease primarily due to cost reduction efforts, reduced refinancing costs that were directly expensed and a settlement in 2004 related to our corporate headquarters lease. These decreases were partially offset by an increase in information technology related costs.

(3) Decrease primarily due to legal entity restructurings in 2003, which resulted in reduced franchise tax costs.

(4) Decrease primarily due to the impact of lower headcount partially offset by higher long-term incentive compensation benefits in 2004 of $21 million primarily due to the Key Employee Award Program expense of $25 million.

Loss on Sales of Receivables. The decrease of $3 million is primarily due to our ceasing to record sales of receivables as sales for accounting purposes due to the amendment of the facility in September 2004, partially offset by an increase in the amount of receivables sold in 2004. See note 6 to our consolidated financial statements.

Accrual for Payment to CenterPoint Energy, Inc. See note 13(d) to our consolidated financial statements.

Gain on Sale of Counterparty Claim. See note 13(e) to our consolidated financial statements.

Gains on Sales of Assets and Emission Allowances, Net. See note 19 to our consolidated financial statements.

Wholesale Energy Goodwill Impairment. See note 4 to our consolidated financial statements.

Depreciation and Amortization.

Equipment impairment charge in 2004 related to turbines and generators	$ 16
Accelerated depreciation on Wayne facility in 2004 due to early retirement	12
Early retirement of certain units at Sayreville and Etiwanda facilities in 2003	(14)
Depreciation for four power generation facilities achieving commercial operation in late July 2003 (Hunterstown and Choctaw), February 2004 (Bighorn) and late October 2004 (new Seward)	35
Net increase in amortization of emission allowances	27
Information systems placed into service during 2004	13
Write-off of software development costs	8
Net change in write-down of office building to fair value less costs to sell in 2003 and 2004	(5)
Other, net	3
Net increase in expense	$ 95

Other, net. Other, net changed by $4 million during 2004 compared to 2003 due primarily to a gain of $9 million recognized in 2004 from the sale of an investment.

Interest Expense.

Higher interest rates	$ 54
Lower capitalized interest	38
Financing fees expensed	24
Amortization of deferred financing costs	(12)
Decrease in outstanding debt	(93)
Net increase in expense	$ 11

Income Tax Expense (Benefit). During 2004 and 2003, our effective tax rates were 29% and not meaningful, respectively. See note 10 to our consolidated financial statements.

Discontinued Operations. See note 20 to our consolidated financial statements.

Liquidity and Capital Resources

Sources of Liquidity and Capital Resources

Our principal sources of liquidity and capital resources are cash flows from operations, borrowings, net proceeds from asset sales, sales of emission allowances and securities offerings. For a description of factors that could affect our liquidity and capital resources, see "Risk Factors" in Item 1A of this Form 10-K and note 12 to our consolidated financial statements.

During 2005, excluding the changes in margin deposits of $1,214 million, we generated $104 million in operating cash flow from continuing operations. In addition, we received (a) $237 million of net proceeds from sales of assets and net sales of emission allowances and (b) $52 million in contingent purchase price payments from the sale of our former European energy operations.

In June 2005, we entered into a collateral arrangement with an energy supplier as a beneficiary in which we granted a security interest in notes receivable related to our receivables facility and related assets of some of our subsidiaries. As a result of this arrangement, the counterparty released approximately $76 million in pledged cash collateral and letters of credit to us. As of December 31, 2005, the collateral arrangement provided $250 million of security, the maximum permitted. In

September 2005, we amended our retail receivables facility to reduce fees, improve terms, extend its maturity until September 2006 and increase the maximum amount that may be borrowed from $350 million to $450 million. In October 2005, we issued $299 million of additional senior secured term loans due 2010.

As of February 13, 2006, we had total available liquidity of $512 million, comprised of $454 million in unused borrowing capacity under our senior secured revolver and $58 million of cash and cash equivalents.

Liquidity and Capital Requirements

Our liquidity and capital requirements primarily reflect our working capital needs, capital expenditures, debt service and collateral requirements. Examples of working capital needs include purchases of fuel and electricity, purchases of emission allowances, plant maintenance costs (including required environmental expenditures) and corporate costs such as payroll. Settlement costs associated with litigation and regulatory proceedings can also have a significant impact on our liquidity and cash requirements. For recent settlements, see note 13 to our consolidated financial statements.

Most counterparties require us to post collateral. The collateral amounts fluctuate depending on commodity prices, price volatility, levels of hedging activity, seasonality and other factors, including changes in our perceived credit standing. As of February 13, 2006, we had posted $2.6 billion in collateral; additional postings of $94 million could have been required by counterparties. Collateral postings increased by $1.5 billion from December 31, 2004 to December 31, 2005 due primarily to natural gas prices, which increased by 68% (based on the 24-month forward NYMEX price of natural gas) for that same period.

Historically, increases in prices of natural gas have caused our collateral postings to increase. However, in October 2005, we agreed to cap prices charged to our "price-to-beat" customers through June 2006. See "Business Regulation Texas" in Item 1 of this Form 10-K for a discussion of these discounts. To manage the supply risks associated with this commitment, we entered into a series of natural gas futures and options through December 2006. As a result of these futures and our remaining wholesale hedges, the impact of natural gas price movements on our level of collateral postings is significantly less than it has been historically. Although we retain exposure to changes in the shape of the natural gas forward curve, and our collateral postings may increase if near term prices fall relative to longer-dated prices, our collateral postings are not expected to fluctuate significantly in response to upward or downward shifts across the natural gas forward curve.

We have taken steps to maintain liquidity reserves that we believe prudent in the face of volatile natural gas prices. Over time, we expect our collateral requirements to decline because of our strategy of entering into fewer long-term hedges for our wholesale energy segment.

Capital Requirements. The following table provides information about our actual and estimated future capital requirements:

	2005	2006	2007	2008
	(in millions)			
Maintenance capital expenditures:				
Retail energy	$ 9	$ 10	$ 8	$ 8
Wholesale energy[1]	28	71	108	59
Other operations	7	10	8	8
	44	91	124	75
Environmental	8	50[2]	85[3]	150[4]
Construction of new generating facilities	30			
Total capital expenditures	$ 82	$ 141	$ 209	$ 225

(1) Excludes $7 million for 2006 through 2011 for pre-existing environmental conditions and remediation, which have been accrued for in our consolidated balance sheet as of December 31, 2005. See "Business Environmental Matters" in Item 1 of this Form 10-K.

(2) We have estimated environmental capital expenditures of $50 million to $70 million for 2006 and have included the low end of the range in the table.

(3) We have estimated environmental capital expenditures of $85 million to $120 million for 2007 and have included the low end of the range in the table.

(4) We have estimated environmental capital expenditures of $150 million to $220 million for 2008 and have included the low end of the range in the table.

Contractual Obligations and Contractual Commitments. The following table includes our obligations and commitments from continuing operations to make future payments under contracts as of December 31, 2005:

Contractual Obligations	Total	2006	2007	2008	2009	2010	2011 and thereafter
	(in millions)						
Debt, including credit facilities[1]	$ 8,077	$ 862[2]	$ 392	$ 392	$ 776	$ 2,254	$ 3,401
REMA operating lease payments	1,188	64	65	62	63	52	882
Other operating lease payments	583	91	65	62	62	60	243
Derivative liabilities	2,033	1,220	410	308	33	24	38
Other commodity commitments	2,290	532	320	180	151	119	988
Maintenance agreements obligations	953	24	52	47	34	63	733
Western states and Cornerstone settlements[3]	158	158					
Other[4]	510	52	31	29	32	26	340
Total contractual cash obligations	$ 15,792	$ 3,003	$ 1,335	$ 1,080	$ 1,151	$ 2,598	$ 6,625

(1)

Includes interest payments. Floating rate debt interest was estimated using projected forward LIBOR rates as of December 31, 2005.

(2) Includes $450 million retail receivables facility and $300 million of term loans to be paid with proceeds from the sale of our New York plants. See note 6 to our consolidated financial statements.

(3) Paid approximately $150 million in January 2006.

(4) Includes stadium naming rights, estimated pension and post retirement benefit payments and other contractual obligations.

As of December 31, 2005, we have estimated minimum sales commitments, which are not classified as derivative assets and liabilities, of (in millions):

2006	$ 2,637
2007	1,286
2008	658
2009	355
2010	198
Total	$ 5,134

Contingencies and Guarantees. We are involved in a number of legal, environmental and other proceedings before courts and are subject to ongoing investigations by certain governmental agencies that could negatively impact our liquidity. See notes 10 and 12 to our consolidated financial statements and "Risk Factors" in Item 1A of this Form 10-K.

We also enter into guarantee and indemnification arrangements in the normal course of business. See note 11(b) to our consolidated financial statements.

Credit Risk

By extending credit to our counterparties, we are exposed to credit risk. For a discussion of our credit risk and policy, see note 2(e) to our consolidated financial statements.

As of December 31, 2005, our derivative assets and accounts receivable from our wholesale energy and ERCOT power supply counterparties, after taking into consideration netting within each contract and any master netting contracts with counterparties, are:

Credit Rating Equivalent	Exposure Before Collateral[1]	Credit Collateral Held[2]	Exposure Net of Collateral	Number of Counterparties >10%[3]	Net Exposure of Counterparties >10%[3]
			(dollars in millions)		
Investment grade	$ 295	$ 67	$ 228		$
Non-investment grade	734		734	1	708
No external ratings:[4]					
Internally rated Investment grade	364		364	1	183
Internally rated Non-investment grade	239	2	237	1	210
Total	$ 1,632	$ 69	$ 1,563	3	$ 1,101

(1) The table excludes amounts related to contracts classified as normal purchases and sales and non-derivative contractual commitments that are not recorded in our consolidated balance sheets, except for any related accounts receivable. Such contractual commitments contain credit and economic risk if a counterparty does not perform. Nonperformance could have a material adverse impact on our future results of operations, financial condition and cash flows.

(2) Collateral consists of cash, standby letters of credit and other forms approved by management.

(3) See note 2(e) to our consolidated financial statements.

(4) For unrated counterparties, we perform credit analyses including review of financial statements, contractual rights and restrictions and credit support such as parent company guarantees to create an internal credit rating.

Off-Balance Sheet Arrangements

As of December 31, 2005, we have no off-balance sheet arrangements. For information regarding our principles of consolidation, see note 2(b) to our consolidated financial statements.

Historical Cash Flows

Cash Flows Operating Activities

2005 Compared to 2004 and 2004 Compared to 2003.

	2005	2004	2003	Change from 2004 to 2005	Change from 2003 to 2004
			(in millions)		
Operating loss	$ (321)	$ (13)	$ (476)	$ (308)	$ 463
Depreciation and amortization	446	453	358	(7)	95
Wholesale energy goodwill impairment			985		(985)
Gains on sales of assets and emission allowances, net	(168)	(20)	(3)	(148)	(17)
Net unrealized losses on energy derivatives	192	224	48	(32)	176
Western states and Cornerstone settlements	359			359	
California reserve changes	(1)	11	(95)	(12)	106
Accrual for (payment to) CenterPoint, net.		(175)	47	175	(222)
Receivables facility proceeds, net		232	23	(232)	209
Margin deposits on energy trading and hedging activities	(1,214)[1]	(451)[1]	223 [2]	(763)	(674)
Net option premiums sold (purchased)	3	(5)	(101)	8	96
Interest payments	(347)	(326)	(286)	(21)	(40)
Change in accounts and notes receivable, net and accounts payable	35 [3]		(98)[4]	35	98
Income tax refunds received (net of income taxes paid)	(22)	62	77	(84)	(15)
Other, net	(72)	13	141	(85)	(128)
Net cash provided by (used in) continuing operations from operating activities	(1,110)	5	843	(1,115)	(838)
Net cash provided by discontinued operations from operating activities	193	101	151	92	(50)
Net cash provided by (used in) operating activities	$ (917)	$ 106	$ 994	$ (1,023)	$ (888)

(1) Change primarily due to both a decrease in net unrealized value of our broker accounts and increased counterparty obligations.

(2) Change primarily due to the conversion of collateral posted to letters of credit from cash.

(3) Change primarily due to increased accounts payable as a result of increased power purchases in our wholesale energy segment, partially offset by increased accounts receivable due to increases in sales prices to our retail customers.

(4) Change primarily due to decreased accounts payable as a result of decreased purchased power and fuel purchases in our wholesale energy segment, partially offset by decreased accounts receivable related to decrease in power sales volumes.

Cash Flows Investing Activities

2005 Compared to 2004 and 2004 Compared to 2003.

	2005	2004	2003	Change from 2004 to 2005	Change from 2003 to 2004
			(in millions)		
Capital expenditures	(82)	(160)	(548)	78 [1]	388 [1]
Proceeds from sales of assets, net	149 [2]	11	2	138	9
Net sales (purchases) of emission allowances	88	(65)	(62)	153	(3)
Restricted cash	14	179	(42)	(165)[3]	221 [3]
Other, net	6	16	4	(10)	12
Net cash provided by (used in) continuing operations from investing activities	175	(19)	(646)	194	627
Net cash provided by discontinued operations from investing activities	131 [4]	919 [5]	1,563 [6]	(788)	(644)
Net cash provided by investing activities	$ 306	$ 900	$ 917	$ (594)	$ (17)

(1) Decrease due to completion of our power generation development projects. Hunterstown and Choctaw were completed in July 2003, Bighorn was completed in February 2004 and new Seward was completed in October 2004.

(2) Includes $76 million, $42 million and $28 million related to sales of El Dorado, REMA hydropower plants and landfill-gas fueled power plants, respectively.

(3) Change primarily due to the refinancing in December 2004.

(4) Includes $100 million of net cash proceeds from the sale of Ceredo.

(5) Includes $804 million of net cash proceeds from the sale of hydropower plants.

(6) Includes $1.4 billion of net cash proceeds from the sale of European energy operations and $285 million of net cash proceeds from the sale of Desert Basin.

Cash Flows Financing Activities

2005 Compared to 2004 and 2004 Compared to 2003.

	2005	2004	2003	Change from 2004 to 2005	Change from 2003 to 2004
			(in millions)		
Payments of senior secured term loans due 2007	$	$ (1,147)	$ (2,048)	$ 1,147	$ 901
Payments of Orion Power MidWest, L.P. term loan and credit facility		(427)	(135)	427	(292)
Payment on senior revolving credit facility			(350)		350
Payments on senior secured revolver due 2007		(183)	(1,108)	183	925
Net borrowings under (payments on) receivables facility	223	(123)		346	(123)
Payments of financing costs	(1)	(72)	(166)	71	94
(Payments) draws under letters of credit to support REMA's lease obligations	(28)	(14)	42	(14)	(56)
Proceeds under a construction agency financing commitment			95		(95)
Proceeds from additional PEDFA bond issuance for new Seward plant		100	100	(100)	
Net borrowings under senior secured revolver due 2009	184	199		(15)	199
Proceeds from senior secured notes		750	1,100	(750)	(350)
Net proceeds from term loans due 2010	190	662		(472)	662
Proceeds from convertible senior subordinated notes			275		(275)
Other, net	26	24	81	2	(57)
Net cash provided by (used in) continuing operations from financing activities	594	(231)	(2,114)	825	1,883
Net cash used in discontinued operations from financing activities		(816)	(775)	816	(41)
Net cash provided by (used in) financing activities	$ 594	$ (1,047)	$ (2,889)	$ 1,641	$ 1,842

New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates

New Accounting Pronouncements

See note 2 to our consolidated financial statements.

Significant Accounting Policies

See note 2 to our consolidated financial statements.

Critical Accounting Estimates

We make a number of estimates and judgments in preparing our consolidated financial statements. These estimates can differ from actual results and have a significant impact on our recorded assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. We consider an estimate to be a critical accounting estimate if it requires a high level of subjectivity or judgment and a significant change in the estimate would have a material impact on our financial condition or results of operations. Each critical accounting estimate affects both our retail energy and wholesale energy segments, unless indicated otherwise. The Audit Committee of our Board of Directors reviews

each critical accounting estimate with our senior management. Further discussion of these accounting policies and estimates is in the notes to our consolidated financial statements.

Goodwill.

We consider the estimate of fair value to be a critical accounting estimate for our wholesale energy segment because (a) a goodwill impairment could have a material impact on our financial position and results of operations and (b) the estimate is based on a number of highly subjective judgments and assumptions. See notes 2(i) and 4 to our consolidated financial statements.

Property, Plant and Equipment.

We consider the fair value estimate used to calculate impairment of property, plant and equipment a critical accounting estimate. This estimate primarily affects our wholesale energy segment, which holds approximately 97% of our total net property, plant and equipment. See note 2(h) to our consolidated financial statements. In determining the existence of an impairment in carrying value, we make a number of subjective assumptions as to:

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of "holding" versus "selling" an asset;
- the forecast of undiscounted expected future cash flow over the asset's estimated useful life; and
- if an impairment exists, the fair value of the asset or asset group.

Derivative Assets and Liabilities.

We report our derivative assets and liabilities, for which the normal purchases and sales exception has not been made, at fair value and consider it to be a critical accounting estimate because they are highly susceptible to change from period to period and are dependent on many subjective factors, including:

- estimated forward market price curves;
- valuation adjustments relating to time value;
- liquidity valuation adjustments;
- costs of administering future obligations under existing contracts; and
- credit adjustments, based on estimated defaults by counterparties.

To determine the fair value for energy derivatives where there are no market quotes or external valuation services, we rely on various modeling techniques. There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

For additional information regarding our derivative assets and liabilities, see notes 2(d) and 5 to our consolidated financial statements and "Quantitative and Qualitative Disclosures about Non-Trading and Trading Activities and Related Market Risks" in Item 7A of this Form 10-K.

Retail Energy Segment Estimated Revenues and Energy Supply Costs.

Accrued Unbilled Revenues. Accrued unbilled revenues of $400 million as of December 31, 2005 represented 4% of our consolidated revenues and 6% of our retail energy segment's revenues for 2005.

Accrued unbilled revenues of $328 million as of December 31, 2004 represented 4% of our consolidated revenues and 5% of our retail energy segment's revenues for 2004.

Accrued unbilled revenues are critical accounting estimates as volumes and rates are not precisely known at the end of each reporting period and the revenue amounts are material. If our estimate of either electricity usage, volumes or estimated rates were to increase or decrease by 3%, our accrued unbilled revenues as of December 31, 2005 would have increased or decreased by approximately $12 million. A 3% increase or decrease in both our estimated electricity usage and estimated rates would have increased or decreased our accrued unbilled revenues as of December 31, 2005 by approximately $24 million.

Estimated Energy Supply Costs. We record energy supply costs for electricity sales and services to retail customers based on estimated supply volumes and an estimated rate per MWh for the applicable reporting period. This is a critical accounting estimate as volumes and rates are not known at the end of each reporting period and the purchased power amounts are material.

A portion of our energy supply costs ($53 million and $57 million as of December 31, 2005 and 2004, respectively) consisted of estimated transmission and distribution charges not yet billed by the transmission and distribution utilities.

In estimating supply volumes, we consider the effects of historical customer volumes, weather factors and usage by customer class. We estimate our transmission and distribution delivery fees using the same method that we use for electricity sales and services to retail customers. In addition, we estimate ERCOT ISO fees based on historical trends, estimated supply volumes and initial ERCOT ISO settlements. Volume estimates are then multiplied by the estimated rate and recorded as purchased power in the applicable reporting period. If our estimate of electricity usage volumes increased or decreased by 3%, our energy supply costs would have increased or decreased by approximately $14 million as of December 31, 2005. Changes in our volume usage would have resulted in a similar offsetting change in billed volumes, thus partially mitigating our energy supply costs.

Dependence on ERCOT ISO Settlement Procedures. Preliminary settlement information is due from the ERCOT ISO within two months after electricity is delivered. Final settlement information is due from the ERCOT ISO within six months after electricity is delivered. The six month settlement received from ERCOT is considered final as ERCOT will only resettle if there are data errors greater than 2% of that day's transaction dollars or if alternate dispute resolutions are granted. We record our estimated supply costs and related fees using estimated supply volumes, as discussed above, and adjust those costs upon receipt of the ERCOT ISO information. Delays in settlements could materially affect the accuracy of our recorded energy supply costs and related fees.

Change in Estimates. See note 2(c) to our consolidated financial statements.

Loss Contingencies.

We record loss contingencies when it is probable that a liability has been incurred and the amount can be reasonably estimated. We consider loss contingency estimates to be critical accounting estimates because they entail significant judgment regarding probabilities and ranges of exposure, and the ultimate outcome of the proceedings is unknown and could have a material adverse effect on our results of operations, financial condition and cash flows. See notes 12 and 13 to our consolidated financial statements.

Deferred Tax Assets, Valuation Allowances and Tax Liabilities.

We estimate (a) income taxes in the jurisdictions in which we operate, (b) net deferred tax assets and liabilities based on expected future taxes in the jurisdictions in which we operate, (c) valuation

allowances for deferred tax assets and (d) contingent tax liabilities for estimated exposures related to our current tax positions. These estimates are considered a critical accounting estimate because they require projecting future operating results (which is inherently imprecise). Also, these estimates depend on assumptions regarding our ability to generate future taxable income during the periods in which temporary differences are deductible. See note 10 to our consolidated financial statements for additional information. During 2005 and 2004, we revised our estimates of certain state tax effective rates and reflected these changes in our state deferred tax assets and liabilities.

As of December 31, 2005, we have not recorded a valuation allowance against our deferred tax assets for federal net operating loss carryforwards. Management believes that it is more likely than not that we will realize the federal net operating loss deferred tax assets. Key factors in this assessment include an evaluation of our recent history of earnings and losses (as adjusted), future reversals of temporary differences and identification of other sources of future taxable income, including the identification of tax planning strategies. However, we have recorded valuation allowances against some deferred tax assets for state operating loss carryforwards. The difference in estimates for federal and state operating loss carryforwards is primarily due to our inability to offset state taxable income in one jurisdiction against state taxable losses in another jurisdiction. During 2005, we released valuation allowances against our capital loss carryforwards as the result of net capital gains recorded during the year and the identification of various tax planning strategies that would make the realization of the remaining capital loss carryforwards more likely than not.

Item 7A. Quantitative and Qualitative Disclosures about Non-Trading and Trading Activities and Related Market Risks.

Market Risks and Risk Management

Our primary market risk exposure relates to fluctuations in commodity prices. We also have market risk exposure related to changes in interest rates. As described in note 2(d) to our consolidated financial statements, we have a risk control framework to manage our risk exposure. However, the effectiveness of this framework can never be completely estimated or fully assured. For example, we could experience hedge ineffectiveness from basis price differences, transmission issues, price correlation issues, volume variation or other factors. In addition, a reduction in market liquidity may impair the effectiveness of our risk management practices and resulting hedge strategies. These and other factors could have a material adverse effect on our results of operations, financial condition and cash flows.

Non-trading Market Risks

Commodity Price Risk

Changes in commodity prices prior to the energy delivery period are inherent in our wholesale and retail energy businesses. We use derivative instruments such as futures, forwards, swaps and options, to execute our wholesale hedge strategy and retail supply procurement strategy as discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations Business Overview" in Item 7 of this Form 10-K.

As of December 31, 2005, the fair values of the contracts related to our net non-trading derivative assets and liabilities are:

Source of Fair Value	2006	2007	2008	2009	2010	2011 and thereafter	Total fair value
				(in millions)			
Prices actively quoted[1]	$ (370)	$ (137)	$ (140)	$ 10	$	$	$ (637)
Prices provided by other external sources[2]	86	139	(16)				209
Prices based on models and other valuation methods[3]	23	(42)	141		3	15	140
Total mark-to-market non-trading derivatives	(261)	(40)	(15)	10	3	15	(288)
Cash flow hedges	(206)	(126)	(49)	(26)	(25)	(39)	(471)
Total	$ (467)	$ (166)	$ (64)	$ (16)	$ (22)	$ (24)	$ (759)

(1) Represents our NYMEX futures positions in natural gas, crude oil and power, which have quoted prices for the next 72, 30 and 36 months, respectively.

(2) Represents our forward positions in natural gas, coal and crude oil and power at points for which over-the-counter market broker quotes are available, which on average, extend 24 or 36 months into the future. Positions are valued against internally developed forward market price curves that are validated and recalibrated against over-the-counter broker quotes. This category includes some transactions whose prices are obtained from external sources and then modeled to hourly, daily or monthly prices, as appropriate.

(3) Represents the value of (a) our valuation adjustments for liquidity, credit and administrative costs, (b) options or structured transactions not quoted by an exchange or over-the-counter broker, but for which the prices of the underlying position are available and (c) 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.

The fair values shown in the table above are subject to significant changes due to fluctuating natural gas and power forward market prices, volatility and credit risk. Market prices assume a functioning market with an adequate number of buyers and sellers to provide 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.

We assess the risk of our non-trading derivatives using a sensitivity analysis that measures the potential loss in fair value based on a hypothetical 10% movement in the underlying energy prices. The gain (loss) impacts from our sensitivity analysis are:

As of December 31,	Market Prices	Fair Value of Cash Flow Hedges	Earnings Impact of Other Derivatives	Total Potential Loss in Fair Value
2005	10% decrease	$ (19)	$ (174)	$ (193)
2004	10% increase	(119)	31	(88)

This risk analysis does not include the favorable impact that the same hypothetical price movements would have on our physical purchases and sales of fuel and power to which the hedges relate. The adverse impact of changes in commodity prices on our portfolio of non-trading energy derivatives held for hedging purposes would be offset by a favorable impact on the underlying hedged physical transactions, assuming:

- the derivatives are not closed out in advance of their expected term;
- the derivatives continue to function effectively as hedges of the underlying risk; and
- as applicable, anticipated underlying transactions settle as expected.

If any of these assumptions cease to be true, we may experience a benefit or loss relative to the exposure hedged. Non-trading energy derivatives that qualify and are effective as cash flow hedges may still have some percentage that is not effective. See notes 2(d) and 5 to our consolidated financial statements.

Interest Rate Risk

As of December 31, 2005, all of our interest rate derivatives either expired or were terminated. We remain subject to the benefits or losses associated with movements in market interest rates related to our long-term debt and bank facility obligations as well as our floating rate debt and certain margin deposits, which are most vulnerable to changes in LIBOR.

We assess interest rate risk using a sensitivity analysis that measures the potential change in our interest expense based on a hypothetical one percentage point movement in the underlying variable interest rate indices.

If interest rates increased (decreased) one percentage point from their December 31, 2005 and 2004 levels, our annual interest expense would have increased (decreased) by $18 million and $12 million, respectively, and our annual interest expense, net of interest income, would have increased (decreased) by $0 and $6 million, respectively.

The above analysis does not include the mitigating effect of our interest rate hedges. If three-month LIBOR had exceeded 4.4%, an additional increase of one percentage point in interest rates would have increased our annual interest expense as of December 31, 2005 and 2004 by $3 million and $0, respectively, and our annual interest expense, net of interest income, would have decreased by $15 million and $6 million, respectively.

We estimated these amounts by considering the impact of hypothetical changes in interest rates on our variable-rate debt adjusted for: cash and cash equivalents and net margin deposits on energy trading and hedging activities outstanding at the respective balance sheet dates.

If interest rates decreased by one percentage point from their December 31, 2005 and 2004 levels, the fair market values of our fixed-rate debt would have increased by $200 million and $233 million, respectively.

Trading Market Risks

Prior to March 2003, we engaged in proprietary trading activities as discussed in note 5 to our consolidated financial statements. Trading positions entered into prior to our decision to exit this business are being closed on economical terms or are being retained and settled over the contract terms.

As of December 31, 2005, the fair values of the contracts related to our legacy trading positions and recorded as net derivative assets and liabilities are:

Source of Fair Value	2006	2007	2008	2009	2010	2011 and thereafter	Total fair value
				(in millions)			
Prices actively quoted	$ 9	$ 12	$	$	$	$	$ 21
Prices provided by other external sources	(10)	(8)	11				(7)
Prices based on models and other valuation methods	(26)	(11)		3			(34)
Total	$ (27)	$ (7)	$ 11	$ 3	$	$	$ (20)

The fair values in the above table are subject to significant changes based on fluctuating market prices and conditions. For further discussion of items that impact our portfolio of trading contracts and an explanation of the sources of fair value, see the discussion related to non-trading derivative assets and liabilities.

Our consolidated realized and unrealized margins relating to these positions are (income (loss)):

	2005	2004
	(in millions)	
Realized	$ (17)	$ (22)
Unrealized	(28)	26
Total	$ (45)	$ 4

An analysis of these net derivative assets and liabilities is:

	2005	2004
	(in millions)	
Fair value of contracts outstanding, beginning of period	$ 26	$ (1)
Contracts transferred to non-trading	(4)	
Contracts realized or settled	22[1]	22
Changes in valuation techniques		
Changes in fair values attributable to market price and other market changes	(64)	5
Fair value of contracts outstanding, end of period Total	$ (20)	$ 26

(1) Amount includes realized loss of $17 million and deferred settlements of $5 million.

We primarily assess the risk of our legacy trading positions using a value-at-risk method to maintain our total exposure within limits set by the Audit Committee of our Board of Directors. Value-at-risk is the potential loss in value of trading positions due to adverse market movements over a defined time period within a specified confidence level. We use the parametric variance/covariance method with delta/gamma approximation to calculate value-at-risk.

Our value-at-risk model utilizes four major parameters:

- *Confidence level* 95% for natural gas and petroleum products and 99% for power products;
- *Volatility* calculated daily from historical forward prices using the exponentially weighted moving average method;
- *Correlation* calculated daily from daily volatilities and historical forward prices using the exponentially weighted moving average method; and
- *Holding period* natural gas and petroleum products generally have two day-holding periods. Power products have holding periods of five to 20 days based on the risk profile of the portfolio and the liquidation period.

While we believe that our value-at-risk assumptions and approximations are reasonable, different assumptions and/or approximations could produce materially different estimates. An inherent limitation of value-at-risk is that past market risk may not produce accurate predictions of

future market risk. In addition, value-at-risk calculated for a specified holding period does not fully capture the market risk of positions that cannot be liquidated or offset with hedges within that specified period. Future transactions, market volatility, reduction of market liquidity, failure of counterparties to satisfy their contractual obligations and/or a failure of risk controls could result in material losses from our legacy trading positions.

The daily value-at-risk for our legacy trading positions is:

	2005	2004
	(in millions)	
As of December 31	$ 7	$ 4
Year Ended December 31:		
Average	3	3
High	9	11
Low		1

Item 8. ***Financial Statements and Supplementary Data.***

The information required by this Item is incorporated by reference from the consolidated financial statements beginning on page F-1.

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

None.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based on this evaluation, these officers have concluded that, as of the end of such period, our disclosure controls and procedures are effective in alerting them on a timely basis to material information required to be included in our reports filed or submitted under the Securities Exchange Act of 1934, as amended.

Management's Report on Internal Control Over Financial Reporting

The information required by this Item is incorporated by reference from "Reliant Energy Inc.'s Report on Internal Control Over Financial Reporting" on page F-1.

Changes in Internal Controls

In connection with the evaluation described above, we identified no change in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during our fiscal quarter ended December 31, 2005 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

None.

PART III

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

See "Business Executive Officers" in Item 1 of this Form 10-K. Pursuant to Instruction G to Form 10-K, we incorporate by reference the information to be disclosed in our definitive proxy statement for the annual stockholder meeting at which we will elect directors ("Proxy Statement").

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

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

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

Item 14. ***Principal Accountant Fees and Services.***

Pursuant to Instruction G to Form 10-K, we incorporate by reference into each of these items the information to be disclosed in our Proxy Statement.

PART IV

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

(a) *List of Documents Filed as Part of this Report*

(1) *Index to Consolidated Financial Statements of Reliant Energy, Inc. and Subsidiaries.*

Reliant Energy, Inc.'s Report on Internal Control Over Financial Reporting	F-1
Report of Independent Registered Public Accounting Firm	F-2
Report of Independent Registered Public Accounting Firm	F-3
Consolidated Statements of Operations for the Years Ended December 31, 2005, 2004 and 2003	F-4
Consolidated Balance Sheets as of December 31, 2005 and 2004	F-5
Consolidated Statements of Cash Flows for the Years Ended December 31, 2005, 2004 and 2003	F-6
Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2005, 2004 and 2003	F-8
Notes to Consolidated Financial Statements	F-11

(2) *Financial Statement Schedule.*

Schedule II Reliant Energy, Inc. and Subsidiaries Reserves for the Years Ended December 31, 2005, 2004 and 2003	F-69

The following schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements: III, IV and V.

The following financial statements are included in this report pursuant to Item 3-16 of Regulation S-X:

Consolidated Financial Statements of Reliant Energy Retail Holdings, LLC and Subsidiaries.

Report of Independent Registered Public Accounting Firm	F-70
Consolidated Statements of Operations for the Years Ended December 31, 2005, 2004 and 2003	F-71
Consolidated Balance Sheets as of December 31, 2005 and 2004	F-72
Consolidated Statements of Cash Flows for the Years Ended December 31, 2005, 2004 and 2003	F-73
Consolidated Statements of Member's Equity and Comprehensive Income for the Years Ended December 31, 2005, 2004 and 2003	F-74
Notes to Consolidated Financial Statements	F-75

Consolidated Financial Statements of Reliant Energy Mid-Atlantic Power Holdings, LLC and Subsidiaries.

Report of Independent Registered Public Accounting Firm	F-91
Consolidated Statements of Operations for the Years Ended December 31, 2005, 2004 and 2003	F-92
Consolidated Balance Sheets as of December 31, 2005 and 2004	F-93
Consolidated Statements of Cash Flows for the Years Ended December 31, 2005, 2004 and 2003	F-94
Consolidated Statements of Member's Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2005, 2004 and 2003	F-95
Notes to Consolidated Financial Statements	F-96

Consolidated Financial Statements of Orion Power Holdings, Inc. and Subsidiaries.

Report of Independent Registered Public Accounting Firm	F-114
Consolidated Statements of Operations for the Years Ended December 31, 2005, 2004 and 2003	F-115
Consolidated Balance Sheets as of December 31, 2005 and 2004	F-116
Consolidated Statements of Cash Flows for the Years Ended December 31, 2005, 2004 and 2003	F-117
Consolidated Statements of Stockholder's Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2005, 2004 and 2003	F-118
Notes to Consolidated Financial Statements	F-119

(3) Index to Exhibits.

The exhibits with the cross symbol (+) are filed with the Form 10-K. The exhibits with the asterisk symbol (*) are compensatory arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.1	Restated Certificate of Incorporation	Reliant Energy, Inc.'s Amendment No. 8 to Registration Statement on Form S-1, dated April 27, 2001	333-48038	3.1
3.2	Second Amended and Restated Bylaws	Reliant Energy, Inc.'s Current Report on Form 8-K, dated September 21, 2004	1-16455	99.1
3.3	Certificate of Ownership and Merger merging a wholly-owned subsidiary into registrant pursuant to Section 253 of the General Corporation Law of the State of Delaware, effective as of April 26, 2004	Reliant Energy, Inc.'s Current Report on Form 8-K, dated April 26, 2004	1-16455	3.1
4.1	Specimen Stock Certificate	Reliant Energy, Inc.'s Amendment No. 5 to Registration Statement on Form S-1, dated March 23, 2001	333-48038	4.1
4.2	Rights Agreement between Reliant Resources, Inc. and The Chase Manhattan Bank, as Rights Agent, including a form of Rights Certificate, dated as of January 15, 2001	Reliant Energy, Inc.'s Amendment No. 8 to Registration Statement on Form S-1, dated April 27, 2001	333-48038	4.2
4.3	Common Stock Warrant Agreement by Reliant Resources, Inc. for the benefit of the holders from time to time, dated as of March 28, 2003	Reliant Energy, Inc.'s Amendment No. 1 to Annual Report on Form 10-K/A for the year ended December 31, 2002	1-16455	4.3
4.4	Indenture relating to 5.00% Convertible Senior Subordinated Notes due 2010 between Reliant Resources, Inc. and Wilmington Trust Company, as Trustee, dated as of June 24, 2003	Reliant Energy, Inc.'s Registration Statement on Form S-3, dated July 24, 2003	333-107295	4.5

4.5	Registration Rights Agreement relating to 5.00% Convertible Senior Subordinated Notes due 2010 among Reliant Resources, Inc., Deutsche Bank Securities Inc., Goldman, Sachs & Co. and Banc of America Securities LLC, dated as of June 24, 2003	Reliant Energy, Inc.'s Registration Statement on Form S-3, dated July 24, 2003	333-107295	4.7
4.6	Indenture relating to 9.25% Senior Secured Notes due 2010 among Reliant Resources, Inc., the Guarantors listed in Schedule I thereto and Wilmington Trust Company, as Trustee, dated as of July 1, 2003	Reliant Energy, Inc.'s Registration Statement on Form S-4, dated July 24, 2003	333-107297	4.5
4.7	Indenture relating to 9.50% Senior Secured Notes due 2013 among Reliant Resources, Inc., the Guarantors listed in Schedule I thereto and Wilmington Trust Company, as Trustee, dated as of July 1, 2003	Reliant Energy, Inc.'s Registration Statement on Form S-4, dated July 24, 2003	333-107297	4.7
4.8	Form of Senior Indenture to be issued under universal shelf	Reliant Energy, Inc.'s Amendment No. 1 to Registration Statement on Form S-3, dated December 10, 2003	333-107296	4.5
4.9	Form of Subordinated Indenture to be issued under universal shelf	Reliant Energy, Inc.'s Amendment No. 1 to Registration Statement on Form S-3, dated December 10, 2003	333-107296	4.6
4.10	Senior Indenture among Reliant Energy, Inc. and Wilmington Trust Company, dated as of December 22, 2004	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 27, 2004	1-16455	4.1

4.11	First Supplemental Indenture relating to 6.75% Senior Secured Notes due 2014 between Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated as of December 22, 2004	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 27, 2004	1-16455	4.2
4.12	Indenture between Orion Power Holdings, Inc. and Wilmington Trust Company, dated as of April 27, 2000	Orion Power Holdings, Inc. Registration Statement on Form S-1, dated August 18, 2000	333-44118	4.1
10.1	Master Separation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated as of December 31, 2000	CenterPoint Energy Houston Electric, LLC's (formerly known as Reliant Energy, Incorporated) Quarterly Report on Form 10-Q for the quarter ended March 31, 2001	1-3187	10.1
10.2	Tax Allocation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated as of December 31, 2000	CenterPoint Energy Houston Electric, LLC's (formerly known as Reliant Energy, Incorporated) Quarterly Report on Form 10-Q for the quarter ended March 31, 2001	1-3187	10.8
10.3	Second Amended and Restated Credit and Guaranty Agreement among (i) Reliant Energy, Inc., as Borrower; (ii) the Other Loan Parties referred to therein, as Guarantors; (iii) the Lenders party thereto; (iv) Bank of America, N.A., as Administrative Agent and Collateral Agent; (v) Barclays Bank PLC and Deutsche Bank Securities Inc., as Syndication Agents; and (vi) Goldman Sachs Credit Partners L.P. and Merrill Lynch Capital Corporation, as Documentation Agents, dated as of December 22, 2004	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 27, 2004	1-16455	10.1

10.4	Amendment No. 1 to Second Amended and Restated Credit and Guaranty Agreement, dated as of October 26, 2005	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 20, 2005	1-16455	10.3
10.5	Amendment No. 2 to Second Amended and Restated Credit and Guaranty Agreement, dated as of December 19, 2005	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 20, 2005	1-16455	10.1
10.6	Credit and Guaranty Agreement between (i) Reliant Energy, Inc., as Borrower; (ii) the Other Loan Parties, as Guarantors; (iii) the Other Lenders; (iv) Deutsche Bank AG, New York Branch, as Administrative Agent; and (v) Deutsche Bank Securities Inc., as Sole Lead Arranger, Sole Bookrunner and Sole Syndication Agent, dated as of October 7, 2005	Reliant Energy, Inc.'s Current Report on Form 8-K, dated October 11, 2005	1-16455	10.1
10.7	Amendment No. 1 to Credit and Guaranty Agreement, dated as of October 26, 2005	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 20, 2005	1-16455	10.4
10.8	Amendment No. 2 to Credit and Guaranty Agreement, dated as of December 19, 2005	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 20, 2005	1-16455	10.2
10.9	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project) Series 2001A between Reliant Energy, Inc., as Guarantor, and J.P. Morgan Trust Company, National Association, as Trustee, dated as of December 22, 2004	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 27, 2004	1-16455	10.2

10.10	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project) Series 2002A between Reliant Energy, Inc., as Guarantor, and J.P. Morgan Trust Company, National Association, as Trustee, dated as of December 22, 2004	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 27, 2004	1-16455	10.3
10.11	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project) Series 2002B between Reliant Energy, Inc., as Guarantor, and J.P. Morgan Trust Company, National Association, as Trustee, dated as of December 22, 2004	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 27, 2004	1-16455	10.4
10.12	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project) Series 2003A between Reliant Energy, Inc., as Guarantor, and J.P. Morgan Trust Company, National Association, as Trustee, dated as of December 22, 2004	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 27, 2004	1-16455	10.5

10.13	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project) Series 2004A between Reliant Energy, Inc., as Guarantor, and J.P. Morgan Trust Company, National Association, as Trustee, dated as of December 22, 2004	Reliant Energy, Inc.'s Current Report on Form 8-K, dated December 27, 2004	1-16455	10.6
10.14	Facility Lease Agreement between Conemaugh Lessor Genco LLC and Reliant Energy Mid-Atlantic Power Holdings, LLC, dated as of August 24, 2000	Reliant Energy Mid-Atlantic Power Holdings, LLC's Registration Statement on Form S-4, dated December 8, 2000	333-51464	4.6a
10.15	Schedule identifying substantially identical agreements to Facility Lease Agreement constituting Exhibit 10.14	Reliant Energy Mid-Atlantic Power Holdings, LLC's Registration Statement on Form S-4, dated December 8, 2000	333-51464	4.6b
10.16	Pass Through Trust Agreement between Reliant Energy Mid-Atlantic Power Holdings, LLC and Bankers Trust Company, made with respect to the formation of the Series A Pass Through Trust and the issuance of 8.554% Series A Pass Through Certificates, dated as of August 24, 2000	Reliant Energy Mid-Atlantic Power Holdings, LLC's Registration Statement on Form S-4, dated December 8, 2000	333-51464	4.4a
10.17	Schedule identifying substantially identical agreements to Pass Through Trust Agreement constituting Exhibit 10.16	Reliant Energy Mid-Atlantic Power Holdings, LLC's Registration Statement on Form S-4, dated December 8, 2000	333-51464	4.4b

10.18	Participation Agreement among (i) Conemaugh Lessor Genco LLC, as Owner Lessor; (ii) Reliant Energy Mid-Atlantic Power Holdings, LLC, as Facility Lessee; (iii) Wilmington Trust Company, as Lessor Manager; (iv) PSEGR Conemaugh Generation, LLC, as Owner Participant; (v) Bankers Trust Company, as Lease Indenture Trustee; and (vi) and Bankers Trust Company, as Pass Through Trustee, dated as of August 24, 2000	Reliant Energy Mid-Atlantic Power Holdings, LLC's Registration Statement on Form S-4, dated December 8, 2000	333-51464	4.5a
10.19	Schedule identifying substantially identical agreements to Participation Agreement constituting Exhibit 10.18	Reliant Energy Mid-Atlantic Power Holdings, LLC's Registration Statement on Form S-4, dated December 8, 2000	333-51464	4.5b
+10.20	First Amendment to Participation Agreement, dated as of November 15, 2001			
+10.21	Schedule identifying substantially identical agreements to First Amendment to Participation Agreement constituting Exhibit 10.20			
+10.22	Second Amendment to Participation Agreement, dated as of June 18, 2003			
+10.23	Schedule identifying substantially identical agreements to Second Amendment to Participation Agreement constituting Exhibit 10.22			

10.24	Lease Indenture of Trust, Mortgage and Security Agreement between Conemaugh Lessor Genco LLC, as Owner Lessor, and Bankers Trust Company, as Lease Indenture Trustee, dated as of August 24, 2000	Reliant Energy Mid-Atlantic Power Holdings, LLC's Registration Statement on Form S-4, dated December 8, 2000	333-51464	4.8a
10.25	Schedule identifying substantially identical agreements to Lease Indenture of Trust constituting Exhibit 10.24	Reliant Energy Mid-Atlantic Power Holdings, LLC's Registration Statement on Form S-4, dated December 8, 2000	333-51464	4.8b
10.26	Purchase and Sale Agreement by and between Orion Power Holdings, Inc., Reliant Energy, Inc., Great Lakes Power Inc. and Brascan Corporation, dated as of May 18, 2004	Reliant Energy, Inc.'s Current Report on Form 8-K, dated May 21, 2004	1-16455	99.2
10.27	Purchase and Sale Agreement between Orion Power Holdings, Inc., as Seller, Reliant Energy, Inc., as Guarantor, and Astoria Generating Company Acquisitions, L.L.C., as Buyer, dated as of September 30, 2005	Reliant Energy, Inc.'s Current Report on Form 8-K, dated October 6, 2005	1-16455	10.1
10.28	Settlement and Release of Claims Agreement between among each of the Reliant Parties, OMOI, each of the California Parties, each of the Additional Claimants, each of the Class Action Parties and each of the Local Governmental Parties (each as defined therein), dated as of October 12, 2005	Reliant Energy, Inc.'s Current Report on Form 8-K, dated October 20, 2005	1-16455	10.1

*10.29	Executive Life Insurance Plan, effective as of January 1, 1994, including the first and second amendments thereto (Reliant Energy, Inc. has adopted certain obligations under this plan with respect to the following individuals: James Ajello, Daniel Hannon and Brian Landrum)	Reliant Energy, Inc.'s Amendment No. 8 to Registration Statement on Form S-1, dated April 27, 2001	333-48038	10.30
*10.30	Transition Stock Plan, effective as of May 4, 2001	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2001	1-16455	10.37
*10.31	2002 Stock Plan, effective as of March 1, 2002	Reliant Energy, Inc.'s Registration Statement on Form S-8, dated April 19, 2002	333-86610	4.5
*10.32	Annual Incentive Compensation Plan, effective as of January 1, 2001	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2001	1-16455	10.9
*10.33	2002 Annual Incentive Compensation Plan for Executive Officers, effective as of March 1, 2002	Reliant Energy, Inc.'s 2002 Proxy Statement on Schedule 14A	1-16455	Appendix I
*10.34	Long Term Incentive Plan, effective as of January 1, 2001	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2001	1-16455	10.10
*10.35	2002 Long-Term Incentive Plan, effective as of June 6, 2002	Reliant Energy, Inc.'s Registration Statement on Form S-8, dated April 19, 2002	333-86612	4.5
*10.36	Deferral Plan, effective as of January 1, 2002	Reliant Energy, Inc.'s Registration Statement on Form S-8, dated December 7, 2001	333-74790	4.1
*10.37	First Amendment to Deferral Plan, effective as of January 14, 2003	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003	1-16455	10.5
*10.38	Successor Deferral Plan, effective as of January 1, 2002	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.30

*10.39	Deferred Compensation Plan, effective as of September 1, 1985, including the first nine amendments thereto (This is now a part of the plan listed as Exhibit 10.38)	Reliant Energy, Inc.'s Amendment No. 8 to Registration Statement on Form S-1, dated April 27, 2001	333-48038	10.25
*10.40	Deferred Compensation Plan, as amended and restated effective as of January 1, 1989, including the first nine amendments (This is now a part of the plan listed as Exhibit 10.38)	Reliant Energy, Inc.'s Amendment No. 8 to Registration Statement on Form S-1, dated April 27, 2001	333-48038	10.26
*10.41	Deferred Compensation Plan, as amended and restated effective as of January 1, 1991, including the first ten amendments thereto (This is now a part of the plan listed as Exhibit 10.38)	Reliant Energy, Inc.'s Amendment No. 8 to Registration Statement on Form S-1, dated April 27, 2001	333-48038	10.27
*10.42	Benefit Restoration Plan, as amended and restated effective as of July 1, 1991, including the first amendment thereto (This is now a part of the plan listed as Exhibit 10.38)	Reliant Energy, Inc.'s Amendment No. 8 to Registration Statement on Form S-1, dated April 27, 2001	333-48038	10.12
*10.43	Key Employee Award Program 2004-2006 of the 2002 Long-Term Incentive Plan and the Form of Agreement for Key Employee Award Program, effective as of February 13, 2004	Reliant Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004	1-16455	10.1
+*10.44	First Amendment to the Key Employee Award Program, effective as of August 10, 2005			
*10.45	Form of 2002 Stock Plan Nonqualified Stock Option Award Agreement, 2003 Grants	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.39
*10.46	Form of 2002 Stock Plan Restricted Stock Award Agreement, 2003 Grants	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.40

+*10.47	Change in Control Agreement between Reliant Energy, Inc., Reliant Energy Corporate Services, LLC and Joel V. Staff, effective as of January 15, 2006			
+*10.48	Severance Agreement between Reliant Resources, Inc. and Mark M. Jacobs, effective as of August 1, 2005			
+*10.49	Change in Control Agreement between Reliant Energy, Inc., Reliant Energy Corporate Services, LLC and Mark M. Jacobs, effective as of March 13, 2006			
+*10.50	Change in Control Agreement between Reliant Energy, Inc., Reliant Energy Corporate Services, LLC and Michael L. Jines, effective as of January 15, 2006			
+*10.51	Change in Control Agreement between Reliant Energy, Inc., Reliant Energy Corporate Services, LLC and Brian Landrum, effective as of January 15, 2006			
+*10.52	Change in Control Agreement between Reliant Energy, Inc., Reliant Energy Corporate Services, LLC and Jerry J. Langdon, effective as of January 15, 2006			
*10.53	Severance Agreement between Reliant Resources, Inc. and James B. Robb, effective as of January 14, 2003	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003	1-16455	10.4
+*10.54	Amendment to Severance Agreement between Reliant Resources, Inc. and James B. Robb, effective as of November 29, 2005			

*10.55	Severance Agreement between Reliant Resources, Inc. and Robert W. Harvey, effective as of May 30, 2003	Reliant Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2003	1-16455	10.1
*10.56	Amendment to Severance Agreement between Reliant Energy, Inc. and Robert W. Harvey, effective as of February 21, 2005	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.43
+*10.57	Reliant Energy, Inc. Executive Severance Plan, effective as of January 1, 2006			
*10.58	Form of 2002 Long-Term Incentive Plan Nonqualified Stock Option Award Agreement for Directors	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.53
*10.59	Form of 2002 Long-Term Incentive Plan Restricted Stock Award Agreement for Directors	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.54
*10.60	Form of 2002 Long-Term Incentive Plan Quarterly Restricted and Premium Restricted Stock Units Award Agreement for Directors	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.55
*10.61	Form of 2002 Long-Term Incentive Plan Quarterly Common Stock and Premium Restricted Stock Award Agreement for Directors	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.56
*10.62	Schedule of 2005 director fees	Reliant Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.57
+*10.63	Reliant Energy, Inc. Non-Employee Directors' Compensation Program, effective as of January 1, 2006			
+12.1	Reliant Energy, Inc. and Subsidiaries Ratio of Earnings from Continuing Operations to Fixed Charges			
+21.1	Subsidiaries of Reliant Energy, Inc.			

+23.1	Consent of Deloitte & Touche LLP
+31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
+31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
+32.1	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

RELIANT ENERGY, INC.
(Registrant)

March 15, 2006 By: /s/ JOEL V. STAFF

Joel V. Staff
Chairman and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of March 15, 2006.

Signature	Title
/s/ JOEL V. STAFF **Joel V. Staff**	**Chairman and Chief Executive Officer (Principal Executive Officer)**
/s/ MARK M. JACOBS **Mark M. Jacobs**	**Executive Vice President and Chief Financial Officer (Principal Financial Officer)**
/s/ THOMAS C. LIVENGOOD **Thomas C. Livengood**	**Senior Vice President and Controller (Principal Accounting Officer)**
/s/ E. WILLIAM BARNETT **E. William Barnett**	**Director**
/s/ DONALD J. BREEDING **Donald J. Breeding**	**Director**
/s/ KIRBYJON H. CALDWELL **Kirbyjon H. Caldwell**	**Director**
/s/ STEVEN L. MILLER **Steven L. Miller**	**Director**
/s/ LAREE E. PEREZ **Laree E. Perez**	**Director**
/s/ WILLIAM L. TRANSIER **William L. Transier**	**Director**

RELIANT ENERGY, INC.'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Reliant Energy, Inc. and its subsidiaries (the Company) is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2005. In making this assessment, our management used the criteria set forth in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment we believe that, as of December 31, 2005, our internal control over financial reporting is effective based on those criteria.

Our independent auditors have issued an audit report on our assessment of our internal control over financial reporting. This report appears on page F-2.

/s/ JOEL V. STAFF	/s/ MARK M. JACOBS
Joel V. Staff Chairman and Chief Executive Officer	Mark M. Jacobs Executive Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Reliant Energy, Inc. and Subsidiaries
Houston, Texas

We have audited management's assessment, included in Reliant Energy, Inc.'s Report on Internal Control Over Financial Reporting on page F-1 that Reliant Energy, Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005 based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule for the year ended December 31, 2005 of the Company and our report dated March 14, 2006 expressed an unqualified opinion on those financial statements and financial statement schedule.

DELOITTE & TOUCHE LLP

Houston, Texas
March 14, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Reliant Energy, Inc. and Subsidiaries
Houston, Texas

We have audited the accompanying consolidated balance sheets of Reliant Energy, Inc. and subsidiaries (the "Company"), as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule (Schedule II Reserves) listed in the Index at Item 15(a)(2). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our 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 Reliant Energy, Inc. and subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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 2 to the consolidated financial statements, the Company changed its accounting for major maintenance to the "expense as incurred" method in 2004; and asset retirement obligations, energy trading contracts, consolidation of variable interest entities and its presentation of revenues and costs of sales associated with non-trading commodity derivative activities in 2003.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 14, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

Houston, Texas
March 14, 2006

RELIANT ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Thousands of Dollars, except per share amounts)

	2005	2004	2003
Revenues:			
Revenues (including $(218,081), $(32,007) and $(54,864) unrealized losses)	$ 9,711,995	$ 8,098,222	$ 10,096,789
Expenses:			
Purchased power, fuel and cost of gas sold (including $25,846, $(192,395) and $7,270 unrealized gains (losses))	8,365,921	6,564,137	7,911,615
Operation and maintenance	736,954	782,462	809,040
Selling, general and administrative	292,486	326,171	428,453
Western states and Cornerstone settlements	359,436		
Loss on sales of receivables		33,741	37,613
Accrual for payment to CenterPoint Energy, Inc.		1,600	46,700
Gain on sale of counterparty claim		(30,000)	
Gains on sales of assets and emission allowances, net	(168,114)	(19,834)	(2,819)
Wholesale energy goodwill impairment			985,000
Depreciation and amortization	445,871	453,042	356,845
Total operating expense	10,032,554	8,111,319	10,572,447
Operating Loss	(320,559)	(13,097)	(475,658)
Other Income (Expense):			
Income (loss) of equity investments, net	25,458	(9,478)	(1,652)
Other, net	(22,672)	13,455	8,435
Interest expense	(399,281)	(417,514)	(406,809)
Interest income	23,227	34,960	34,955
Total other expense	(373,268)	(378,577)	(365,071)
Loss from Continuing Operations Before Income Taxes	(693,827)	(391,674)	(840,729)
Income tax expense (benefit)	(253,080)	(115,214)	75,092
Loss from Continuing Operations	(440,747)	(276,460)	(915,821)
Income (loss) from discontinued operations	110,799	239,800	(402,241)
Loss Before Cumulative Effect of Accounting Changes	(329,948)	(36,660)	(1,318,062)
Cumulative effect of accounting changes, net of tax	(608)	7,290	(24,055)
Net Loss	$ (330,556)	$ (29,370)	$ (1,342,117)
Basic and Diluted Earnings (Loss) per Share:			
Loss from continuing operations	$ (1.46)	$ (0.93)	$ (3.12)
Income (loss) from discontinued operations	0.37	0.81	(1.37)
Loss before cumulative effect of accounting changes	(1.09)	(0.12)	(4.49)
Cumulative effect of accounting changes, net of tax		0.02	(0.08)

	2005	2004	2003
Net loss	$ (1.09)	$ (0.10)	$ (4.57)

See Notes to our Consolidated Financial Statements

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RELIANT ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars, except per share amounts)

	December 31,	
	2005	**2004**
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 88,397	$ 105,054
Restricted cash	26,906	15,610
Accounts and notes receivable, principally customer, net of allowance of $34,054 and $41,636	1,171,673	1,071,312
Inventory	299,099	245,682
Derivative assets	725,964	305,924
Margin deposits on energy trading and hedging activities	1,716,035	505,547
Accumulated deferred income taxes	361,547	118,032
Prepayments and other current assets	137,498	186,414
Current assets of discontinued operations	203,332	104,276
Total current assets	4,730,451	2,657,851
Property, Plant and Equipment, net	5,934,060	6,437,761
Other Assets:		
Goodwill	386,594	440,534
Other intangibles, net	510,582	540,583
Net California receivables subject to refund		200,086
Equity investments	29,524	83,819
Derivative assets	527,799	272,254
Prepaid lease	259,412	243,463
Restricted cash		25,547
Other	309,588	259,367
Long-term assets of discontinued operations	880,796	1,032,759
Total other assets	2,904,295	3,098,412
Total Assets	$ 13,568,806	$ 12,194,024
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt and short-term borrowings	$ 789,325	$ 618,854
Accounts payable, principally trade	886,965	566,104
Derivative liabilities	1,219,954	401,881
Margin deposits from customers on energy trading and hedging activities	15,588	19,040
Other	397,942	463,528
Current liabilities of discontinued operations	96,456	29,184
Total current liabilities	3,406,230	2,098,591
Other Liabilities:		
Accumulated deferred income taxes	69,421	229,352
Derivative liabilities	812,695	311,222
Other	319,662	387,223
Long-term liabilities of discontinued operations	779,678	842,425
Total other liabilities	1,981,456	1,770,222

	December 31,	
Long-term Debt	4,317,427	3,938,857
Commitments and Contingencies		
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; 304,900,193 and 299,812,305 issued)	66	61
Additional paid-in capital	5,846,747	5,790,007
Treasury stock at cost (0 and 128,264 shares)		(2,209)
Retained deficit	(1,698,504)	(1,367,948)
Accumulated other comprehensive loss	(284,281)	(29,351)
Accumulated other comprehensive loss of discontinued operations	(335)	(4,206)
Total stockholders' equity	3,863,693	4,386,354
Total Liabilities and Stockholders' Equity	$ 13,568,806	$ 12,194,024

See Notes to our Consolidated Financial Statements

RELIANT ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)

	2005	2004	2003
Cash Flows from Operating Activities:			
Net loss	$ (330,556)	$ (29,370)	$ (1,342,117)
(Income) loss from discontinued operations	(110,799)	(239,800)	402,241
Net loss from continuing operations and cumulative effect of accounting changes	(441,355)	(269,170)	(939,876)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Cumulative effect of accounting changes	608	(7,290)	24,055
Wholesale energy goodwill impairment			985,000
Depreciation and amortization	445,871	453,042	356,845
Deferred income taxes	(278,992)	(108,688)	55,259
Net unrealized losses on energy derivatives	192,235	224,402	47,594
Amortization of deferred financing costs	15,110	77,881	89,619
Gains on sales of assets and emission allowances, net	(168,114)	(19,834)	(2,819)
Western states and Cornerstone settlements	359,436		
(Income) loss of equity investments, net	(25,458)	9,478	1,652
Accrual for payment to CenterPoint Energy, Inc.		1,600	46,700
Other, net	27,498	(7,058)	(4,971)
Changes in other assets and liabilities:			
Accounts and notes receivable, net	(109,736)	(59,723)	106,217
Receivables facility proceeds, net		232,000	23,000
Inventory	(42,253)	(14,744)	25,323
Margin deposits on energy trading and hedging activities, net	(1,213,940)	(450,851)	223,173
Net derivative assets and liabilities	10,978	12,547	(71,152)
Accounts payable	144,466	59,233	(204,522)
Payment to CenterPoint Energy, Inc.		(176,600)	
Other current assets	33,071	(37,399)	(29,722)
Other assets	(32,605)	(5,562)	(54,285)
Taxes payable/receivable	3,053	47,652	44,721
Other current liabilities	(34,479)	1,815	78,446
Other liabilities	4,495	42,617	42,097
Net cash provided by (used in) continuing operations from operating activities	(1,110,111)	5,348	842,354
Net cash provided by discontinued operations from operating activities	192,948	100,165	151,356
Net cash provided by (used in) operating activities	(917,163)	105,513	993,710
Cash Flows from Investing Activities:			
Capital expenditures	(82,296)	(159,671)	(548,391)
Proceeds from sales of assets, net	149,345	11,325	2,591
Proceeds from sales of emission allowances	234,421	59,662	14,073
Purchases of emission allowances	(145,769)	(124,241)	(76,486)
Restricted cash	14,251	178,885	(42,214)
Other	5,500	16,207	4,400
Net cash provided by (used in) continuing operations from investing activities	175,452	(17,833)	(646,027)
Net cash provided by discontinued operations from investing activities	130,700	919,043	1,563,495
Net cash provided by investing activities	306,152	901,210	917,468
Cash Flows from Financing Activities:			
Proceeds from long-term debt	299,000	1,512,000	1,612,120
Payments of long-term debt	(148,333)	(1,597,568)	(2,141,137)
Increase (decrease) in short-term borrowings and revolving credit facilities, net	407,000	(108,350)	(1,425,445)
Proceeds from issuances of stock	37,885	24,618	7,531

	2005	2004	2003
Payments of financing costs	(1,198)	(71,884)	(166,407)
Other, net		9,156	
Net cash provided by (used in) continuing operations from financing activities	594,354	(232,028)	(2,113,338)
Net cash used in discontinued operations from financing activities		(815,885)	(775,482)
Net cash provided by (used in) financing activities	594,354	(1,047,913)	(2,888,820)

Effect of Exchange Rate Change on Cash			9,071
Net Change in Cash and Cash Equivalents	(16,657)	(41,190)	(968,571)
Cash and Cash Equivalents at Beginning of Period	105,054	146,244	1,114,815
Cash and Cash Equivalents at End of Period	$ 88,397	$ 105,054	$ 146,244
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest paid (net of amounts capitalized) for continuing operations	$ 347,249	$ 326,366	$ 285,987
Income taxes paid (net of income tax refunds received) for continuing operations	$ 21,812	$ (61,808)	$ (77,402)

See Notes to our Consolidated Financial Statements

RELIANT ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

(Thousands of Dollars)

	Common Stock	Additional Paid In Capital	Treasury Stock	Retained Earnings (Deficit)	Unrealized Gain (Loss) on Available For Sale Securities	Deferred Derivative Gains (Losses)	Foreign Currency Translation Adjustments	Additional Minimum Benefits Liability	Total Accumulated Other Comprehensive Income (Loss)	Discontinued Operations Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
Balance December 31, 2002	$ 61	$ 5,836,957	$ (158,483)	$ 3,539	$ 1,116	$ (14,642)	$ (1,524)	$ (2,646)	$ (17,696)	$ (11,490)	$ 5,652,888	
Net loss				(1,342,117)							(1,342,117)	$ (1,342,117)
Contributions from CenterPoint Energy, Inc.		45,498									45,498	
Issuance of warrants		14,360									14,360	
Transactions under stock plans		(55,377)	68,714								13,337	
Other comprehensive income (loss):												
Foreign currency translation adjustments, net of tax of $0 and $17 million $98 million							543		543	(34,343)	(33,800)	543
Changes in minimum pension liability, net of tax of $1 million								1,369	1,369		1,369	1,369
Deferred gain from cash flow hedges, net of tax of $45 million and $8 million						75,808			75,808	(14,509)	61,299	75,808
Reclassification of net deferred gain from cash flow hedges into net loss, net of tax of $61 million and $21 million						(79,466)			(79,466)	39,545	(39,921)	(79,466)
Unrealized loss on available-for-sale securities, net of tax of $0					(350)				(350)		(350)	(350)
Reclassification adjustments for gains on sales of available-for-sale securities realized in net loss, net of tax of $0					(764)				(764)		(764)	(764)
Other comprehensive loss from discontinued operations												(9,307)

	Common Stock	Additional Paid In Capital	Treasury Stock	Retained Earnings (Deficit)	Unrealized Gain (Loss) on Available For Sale Securities	Deferred Derivative Gains (Losses)	Foreign Currency Translation Adjustments	Additional Minimum Benefits Liability	Total Accumulated Other Comprehensive Income (Loss)	Discontinued Operations Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
Comprehensive loss												$ (1,354,284)
Balance December 31, 2003	61	5,841,438	(89,769)	(1,338,578)	2	(18,300)	(981)	(1,277)	(20,556)	(20,797)	4,371,799	

See Notes to our Consolidated Financial Statements

RELIANT ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS) (Continued)
(Thousands of Dollars)

	Common Stock	Additional Paid In Capital	Treasury Stock	Retained Earnings (Deficit)	Unrealized Gain (Loss) on Available For Sale Securities	Deferred Derivative Gains (Losses)	Foreign Currency Translation Adjustments	Additional Minimum Benefits Liability	Total Accumulated Other Comprehensive Income (Loss)	Discontinued Operations Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
Net loss				(29,370)							(29,370)	$ (29,370)
Distribution to CenterPoint Energy, Inc.		(509)									(509)	
Warrants		57									57	
Transactions under stock plans		(50,979)	87,560								36,581	
Other comprehensive income (loss):												
Foreign currency translation adjustments, net of tax of $0							981		981		981	981
Changes in minimum pension liability, net of tax of $1 million								1,129	1,129		1,129	1,129
Deferred gain (loss) from cash flow hedges, net of tax of $24 million and $1 million						42,387			42,387	813	43,200	42,387
Reclassification of net deferred (gain) loss from cash flow hedges into net loss, net of tax of $35 million and $11 million						(53,298)			(53,298)	15,778	(37,520)	(53,298)
Unrealized loss on available-for-sale securities, net of tax of $0					(8)				(8)		(8)	(8)
Reclassification adjustments for gains on sales of available-for-sale securities realized in net loss, net of tax of $0					14				14		14	14
Other comprehensive income from discontinued operations												16,591
Comprehensive loss												$ (21,574)
	$ 61	$ 5,790,007	$ (2,209)	$ (1,367,948)	$ 8	$ (29,211)	$	$ (148)	$ (29,351)	$ (4,206)	$ 4,386,354	

	Common Stock	Additional Paid In Capital	Treasury Stock	Retained Earnings (Deficit)	Unrealized Gain (Loss) on Available For Sale Securities	Deferred Derivative Gains (Losses)	Foreign Currency Translation Adjustment	Additional Minimum Benefits Liability	Total Accumulated Other Comprehensive Income (Loss)	Discontinued Operations Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
Balance December 31, 2004												

See Notes to our Consolidated Financial Statements

RELIANT ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS) (Continued)
(Thousands of Dollars)

	Common Stock	Additional Paid In Capital	Treasury Stock	Retained Earnings (Deficit)	Unrealized Gain (Loss) on Available For Sale Securities	Deferred Derivative Gains (Losses)	Foreign Currency Translation Adjustments	Additional Minimum Benefits Liability	Total Accumulated Other Comprehensive Income (Loss)	Discontinued Operations Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
Net loss				(330,556)							(330,556)	$ (330,556)
Contribution from CenterPoint Energy, Inc.		7,079									7,079	
Warrants		1,411									1,411	
Transactions under stock plans	5	48,250	2,209								50,464	
Other comprehensive income (loss):												
Deferred gain (loss) from cash flow hedges, net of tax of $160 million and $1 million						(233,234)			(233,234)	2,378	(230,856)	(233,234)
Reclassification of net deferred (gain) loss from cash flow hedges into net loss, net of tax of $9 million and $1 million						(21,688)			(21,688)	1,493	(20,195)	(21,688)
Unrealized loss on available-for-sale securities, net of tax of $0					(8)				(8)		(8)	(8)
Other comprehensive income from discontinued operations												3,871
Comprehensive loss												$ (581,615)
Balance December 31, 2005	$ 66	$ 5,846,747	$	$ (1,698,504)	$	$ (284,133)	$	$ (148)	$ (284,281)	$ (335)	$ 3,863,693	

See Notes to our Consolidated Financial Statements

RELIANT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

Background. "Reliant Energy" refers to Reliant Energy, Inc. and "we," "us" and "our" refer to Reliant Energy, Inc. and its consolidated subsidiaries. Our business consists primarily of two business segments, retail energy and wholesale energy. See note 17.

Reliant Energy, a Delaware corporation, was formed in August 2000 by CenterPoint Energy, Inc. (CenterPoint) (known as Reliant Energy, Incorporated at the time) in connection with the planned separation of its regulated and unregulated operations. CenterPoint transferred substantially all of its unregulated businesses to us. In May 2001, Reliant Energy became a publicly traded company and in September 2002, CenterPoint distributed its remaining ownership of our common stock to its shareholders.

Basis of Presentation. All significant intercompany transactions have been eliminated. We have reclassified certain amounts from prior periods to conform to the 2005 presentation. These reclassifications had no impact on reported earnings/losses and are described in notes 2(m), 5, 19 and 20.

(2) Summary of Significant Accounting Policies

(a) Use of Estimates and Market Risk and Uncertainties.

Management makes estimates and assumptions to prepare financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) that affect:

- the reported amount of assets and liabilities,
- the reported amounts of revenues and expenses and
- our disclosure of contingent assets and liabilities at the date of the financial statements.

Our critical accounting estimates include: (a) goodwill, (b) property, plant and equipment, (c) derivative assets and liabilities, (d) retail energy segment estimated revenues and energy supply costs, (e) loss contingencies and (f) deferred tax assets, valuation allowances and tax liabilities. Actual results could differ from our estimates.

We are subject to various risks inherent in doing business. See notes 2(c), 2(d), 2(e), 2(h), 2(p), 3(b), 4, 5, 6, 9, 10, 11 and 12.

(b) Principles of Consolidation.

We include our accounts and those of our wholly-owned and majority-owned subsidiaries in our consolidated financial statements. We do not consolidate three power generating facilities (see note 11(a)), which are under operating leases, or a 50% equity investment in a cogeneration plant. Since September 28, 2004, we have consolidated our receivables facility arrangement (see note 6).

(c) Revenues.

Power Generation Revenues. We record gross revenues from the sale of electricity and other energy services under the accrual method. Electric power and other energy services are sold at market-based prices through existing power exchanges or through third party contracts. Energy sales and services that have been delivered but not billed by period-end are estimated.

Retail Energy Revenues. Gross revenues for energy sales and services to residential and small business customers and our electric sales to large commercial, industrial and governmental/institutional

customers under contracts executed after October 2002 are recognized upon delivery and include estimated energy and services delivered but not billed by the end of the period. Our electric sales to large commercial, industrial and governmental/institutional customers under contracts executed before October 2002 were accounted for under the mark-to-market method of accounting upon contract execution. The change in accounting for some of the contracted sales to large commercial, industrial and governmental/institutional customers during 2002 was due to Emerging Issues Task Force (EITF) No. 02-03.

We recorded a cumulative effect of a change in accounting principle of $42 million loss, net of tax of $22 million, or $0.14 per share, effective January 1, 2003, related to EITF No. 02-03. The cumulative effect reflects the fair value, as of January 1, 2003, of contracts executed prior to October 25, 2002 that had been marked to market under EITF No. 98-10 that did not meet the definition of a derivative.

As of December 31, 2005 and 2004, we recorded unbilled revenues of $400 million and $328 million, respectively, for retail energy sales. Accrued unbilled revenues are based on our estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Volume estimates are based on daily forecasted volumes, estimated customer usage by class and applicable customer rates. Unbilled revenues are calculated by multiplying volume estimates by our estimated rates by customer class. Estimated amounts are adjusted when actual usage and rates are known and billed.

Changes in Estimates for Retail Energy Sales and Costs. The revenues and the related energy supply costs in our retail energy segment include our estimates of customer usage after consideration of initial usage information provided by the independent system operators and the distribution companies. We revise these estimates and record any changes in the period as information becomes available (collectively referred to as "market usage adjustments"). During 2005, 2004 and 2003, we recognized in gross margin (revenues less purchased power, fuel and cost of gas sold) $15 million of expense, $18 million of expense and $28 million of income, respectively, related to market usage adjustments.

(d) Derivatives and Hedging Activities.

We account for our derivatives instruments and hedging activities in accordance with SFAS No. 133, "Accounting for Derivatives Instruments and Hedging Activities," as amended (SFAS No. 133).

In the fourth quarter of 2005, we commenced an evaluation of our wholesale energy segment's hedging strategy (which includes both designated and non-designated hedging derivative instruments) and use of capital. In February 2006, we concluded that the benefits of hedging our generation do not justify the costs, including collateral postings. As a result, we decided to substantially reduce new hedges of our generation. We intend to continue entering into selective hedges, including originated transactions, based on (a) our assessment of market fundamentals to increase the return from our generation assets and (b) operational and market limitations requiring us to enter into fuel, capacity and emissions transactions to manage our generation assets. We believe that this new strategy will significantly reduce our wholesale energy segment's use of capital; however, our earnings will be subject to volatility based on market price changes. Existing positions will be closed as economically feasible or in accordance with their terms.

For our retail energy segment, we will continue to focus our supply procurement strategy on (a) matching our supply costs with our fixed price sales commitments and (b) procuring physical supply to manage operational issues and within market liquidity constraints. In conjunction with our revised wholesale energy segment's hedge strategy as discussed above, during the fourth quarter of 2005, we decided to procure third party supply for our PJM retail sales commitments. Historically, we used our PJM Interconnection, LLC (PJM) generation to supply these commitments. This new strategy may result in increased collateral cost to supply our retail energy operations in the PJM market, decreasing our ability to be competitive in this market or reducing our gross margins.

We may also continue to enter into derivatives to manage our exposure to changes in interest rates.

For our hedging activities, we use both derivative and non-derivative contracts that provide for settlement in cash or by delivery of a commodity. The primary types of derivative instruments we use are forwards, futures, swaps and options. We elect one of three accounting methods (cash flow hedge, mark-to-market or accrual accounting) for derivatives based on facts and circumstances. The fair values of our derivative activities are determined by (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods.

If certain conditions are met, a derivative instrument may be designated as a cash flow hedge. A derivative is recognized at fair value in the balance sheet whether or not it is designated as a hedge, except for derivative contracts designated as "normal purchases and sales exceptions," which are not in our consolidated balance sheet or results of operations prior to settlement.

Derivatives designated as cash flow hedges must have a high correlation between price movements in the derivative and the hedged item. The changes in fair value of cash flow hedges are deferred in accumulated other comprehensive income (loss), net of tax, to the extent the contracts are effective as hedges, until the forecasted transactions affect earnings. At the time the forecasted transactions affect earnings, we reclassify the amounts in other comprehensive income into earnings. We record the ineffective portion of changes in fair value of cash flow hedges immediately into earnings. For all other derivatives, changes in fair value are recorded as unrealized gains or losses in our results of operations.

If and when an acceptable level of correlation no longer exists, hedge accounting ceases and changes in fair value are recognized in our results of operations. If it becomes probable that a forecasted transaction will not occur, we immediately recognize the related deferred gains or losses in our results of operations. The associated hedging instrument is then marked to market through our results of operations for the remainder of the contract term unless a new hedging relationship is redesignated.

Prior to October 1, 2003, we generally recorded, on a gross basis in the period of delivery (a) sales in revenues and (b) purchases in purchased power, fuel and cost of gas sold. In July 2003, the EITF issued EITF No. 03-11, which states that realized gains and losses on derivatives contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. EITF No. 03-11 has no impact on margins or net income. Subsequent to October 1, 2003, due to the adoption of EITF No. 03-11, hedging transactions that do not physically flow are included in the same caption as the items being hedged. A summary of our derivative activities and classification in our results of operations is:

Instrument	**Purpose for Holding or Issuing Instrument[(1)]**	**Transactions that Physically Flow**	**Transactions that Financially Settle[(2)]**
Power futures, forward, swap and option contracts	Power sales to end-use retail customers	Revenues	N/A
	Power sales from wholesale operations	Revenues	Revenues
	Supply management revenues	Revenues	Purchased power, fuel and cost of gas sold
	Power purchases related to our retail operations	Purchased power, fuel and cost of gas sold	Purchased power, fuel and cost of gas sold
	Power purchases related to wholesale operations	Purchased power, fuel and cost of gas sold	Revenues
	Power purchases/sales related to our legacy trading positions	Revenues	Revenues
Natural gas and fuel futures, forward, swap and option contracts	Natural gas and fuel purchases/sales related to our retail operations	N/A	Purchased power, fuel and cost of gas sold
	Natural gas and fuel sales related to wholesale operations	Revenues	Purchased power, fuel and cost of gas sold
	Natural gas and fuel purchases related to wholesale operations	Purchased power, fuel and cost of gas sold	Purchased power, fuel and cost of gas sold
	Natural gas and fuel purchases/sales related to our legacy trading positions	Purchased power, fuel and cost of gas sold	Purchased power, fuel and cost of gas sold
Interest rate swaps and caps	Interest rate risk associated with floating-rate debt	N/A	Interest expense

(1) The purpose for holding or issuing is not impacted by the accounting method elected for each instrument.

(2) Includes classification for mark-to-market derivatives and amounts reclassified from accumulated other comprehensive income (loss) related to cash flow hedges.

In addition to market risk, we are exposed to credit and operational risk. We have a control framework to manage these risks, which include: (a) measuring and monitoring these risks, (b) review and approval of new transactions relative to these risks, (c) transaction validation and (d) portfolio valuation and reporting. We use mark-to-market valuation, value-at-risk and other metrics in monitoring and measuring risk. Our risk control framework includes a variety of separate but complementary processes, which involve commercial and senior management and our Board of Directors. See note 2(e) for further discussion of our credit policy.

Earnings Volatility from Derivative Instruments. We purchase most of the generation capacity necessary to supply our retail energy business in Texas from third parties. Our primary objective is to satisfy the forecasted retail load and maintain adequate capacity reserves to manage operational and market constraints. We routinely hedge most of our fixed purchase and sale commitments. Some types of transactions may cause us to experience volatility in our earnings due to the revenue receiving accrual treatment while a portion of the related supply is marked to market. During the third quarter

of 2004, for certain new power capacity commitments, we began electing mark-to-market accounting treatment to partially offset the potential impact of price volatility on our short positions in natural gas.

We procure natural gas, coal, oil, natural gas transportation and storage capacity and other energy-related commodities to support our electric generation assets. Some types of transactions may cause us to experience volatility in our earnings due to natural gas inventory related to transportation and storage generally receiving accrual treatment while the related derivative instruments are marked to market through earnings. Effective July 1, 2004, we began electing mark-to-market accounting treatment for new transactions and transactions in the West region that were previously designated as cash flows hedges.

Effective September 1, 2005, we began marking to market through earnings a portion of our cash flow hedge portfolio related to our PJM coal plants for October 2005 through December 2007 due to ineffectiveness. The ineffectiveness resulted from transmission constraints impacting our generating plants, hotter than average weather and higher natural gas prices.

Set-off of Derivative Assets and Liabilities. Where derivative instruments are subject to a master netting agreement and the accounting criteria to net are met, we present our derivative assets and liabilities on a net basis. Derivative assets/liabilities and accounts receivable/payable are presented and set-off separately in our consolidated balance sheets although in most cases contracts permit the set-off of derivative assets/liabilities and accounts receivable/payable with a given counterparty.

(e) Credit Risk.

We have a credit policy that governs the management of credit risk, including the establishment of counterparty credit limits and specific transaction approvals. Credit risk is monitored daily and the financial condition of our counterparties is reviewed periodically. We try to mitigate credit risk by entering into contracts that permit netting and allow us to terminate upon the occurrence of certain events of default. We measure credit risk as the replacement cost for our derivative positions plus amounts owed for settled transactions.

As of December 31, 2005, two non-investment grade counterparties and one investment grade counterparty represented 59% ($918 million) and 12% ($183 million), respectively, of our credit exposure, net of collateral. As of December 31, 2004, three non-investment grade counterparties represented 48% ($329 million) of our credit exposure, net of collateral. Since December 31, 2004, our credit exposure increased primarily due to changes in commodity prices. There were no other counterparties representing greater than 10% of our credit exposure, net of collateral.

(f) Selling, General and Administrative Expenses.

Selling, general and administrative expenses include (a) selling and marketing, (b) bad debt expense and (c) other general and administrative expenses. Other general and administrative expenses include, among other items, (a) financial services, (b) legal costs, (c) regulatory costs and (d) certain benefit costs.

(g) Severance Costs.

During 2005, 2004 and 2003, we incurred $9 million, $31 million and $31 million, respectively, in severance costs (included in both operation and maintenance and selling, general and administrative expenses), which were substantially paid in each applicable period.

(h) Property, Plant and Equipment and Depreciation Expense.

We compute depreciation using the straight-line method based on estimated useful lives. Depreciation expense was $351 million, $372 million and $303 million during 2005, 2004 and 2003, respectively.

	Estimated Useful Lives (Years)	December 31, 2005	December 31, 2004
		(in millions)	
Electric generation facilities	10-35	$ 6,313	$ 6,502
Building and building improvements	5-15	31	34
Land improvements	20-35	194	197
Other	3-10	445	465
Land		96	98
Assets under construction		34	48
Total		7,113	7,344
Accumulated depreciation		(1,179)	(906)
Property, plant and equipment, net		$ 5,934	$ 6,438

We periodically evaluate property, plant and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. We recorded no material property, plant and equipment impairments during 2005, 2004 and 2003.

In the future, we could recognize impairments if our wholesale energy market outlook changes negatively. In addition, our ongoing evaluation of our wholesale energy business could result in decisions to mothball, retire or dispose of additional generation assets, any of which could result in impairment charges.

(i) Intangible Assets and Amortization Expense.

Goodwill. We perform our goodwill impairment test annually and when events or changes in circumstances indicate that the carrying value may not be recoverable. We previously selected November 1 as our annual goodwill impairment testing date since we had historically completed our annual strategic planning process by that date. We have since modified our strategic planning process, which provides key information used in the analysis of our goodwill impairment test, and such information is no longer completed by November 1. In order to align our annual goodwill impairment test with our annual strategic planning process, to meet the accelerated reporting deadlines and to provide adequate time to complete the analysis each year, beginning in 2005, we changed the date on which we perform our annual goodwill impairment test to April 1. The change is not intended to delay, accelerate or avoid an impairment charge. We believe that this accounting change is to an alternative accounting principle that is preferable under the circumstances.

Other Intangibles. We recognize specifically identifiable intangible assets, including emission allowances, contractual rights, power generation site permits and water rights, when specific rights and contracts are acquired. We have no intangible assets with indefinite lives recorded as of December 31, 2005 and 2004.

(j) Stock-based Compensation.

We apply the intrinsic value method of accounting for employee stock-based compensation and expense it ratably over the vesting period. On January 1, 2006, we began to recognize compensation cost for the unvested portion of pre-January 2006 awards and awards granted from that date based on

the grant-date fair value of those awards. We expect the adoption of the fair value based method of accounting will not have a material impact on our financial position or results of operations. Under the intrinsic value method, we adjust compensation cost for performance-based stock awards and options based on changes in our stock price; however, under the fair value based method, we recognize compensation cost based on grant date fair value recognized over the service period. Under the intrinsic value method, we do not recognize compensation cost for time-based stock options or the employee stock purchase plan; however, under the fair value based method, we recognize compensation cost. The fair value based method of accounting does not change our compensation cost for time-based restricted stock awards or performance-based cash awards.

Using the Black-Scholes model for determining fair values, our pro forma results are:

	2005	2004	2003
	(in millions, except per share amounts)		
Net loss, as reported	$ (331)	$ (29)	$ (1,342)
Add: Stock-based compensation expense included in reported net income/loss, net of tax	5	21	7
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of tax	(17)	(26)	(42)
Pro forma net loss	$ (343)	$ (34)	$ (1,377)
Loss per share:			
Basic and diluted, as reported	$ (1.09)	$ (0.10)	$ (4.57)
Basic and diluted, pro forma	$ (1.13)	$ (0.12)	$ (4.69)

We use the Black-Scholes option-pricing model with the following weighted average assumptions and resulting fair values:

	Options			Employee Stock Purchase Plan Rights		
	2005	2004	2003	2005	2004	2003
Expected life in years	5	5	5	0.5	0.5	0.5
Estimated volatility[1]	45.75%	72.85%	113.64%	32.97%	41.18%	110.73%
Risk-free interest rate	4.18%	3.01%	2.75%	2.94%	1.21%	1.18%
Dividend yield	0%	0%	0%	0%	0%	0%
Weighted-average fair value	$ 5.72	$ 5.00	$ 3.10	$ 3.25	$ 2.29	$ 1.80

(1) For 2005 and 2004 options, we estimated volatility based on an equal weighting of historical and implied volatility of our common stock. For employee stock purchase plan rights and 2003 options, we estimated volatility based on the historical volatility of our common stock.

(k) Capitalization of Interest Expense.

During 2005, 2004 and 2003, we capitalized $0, $46 million and $84 million of interest expense, respectively.

(l) Cash and Cash Equivalents.

We record all highly liquid short-term investments with maturities of three months or less as cash equivalents.

(m) Restricted Cash.

Restricted cash includes cash at certain subsidiaries, the distribution or transfer of which is restricted by financing and other agreements. In our consolidated statements of cash flows for 2004 and 2003, we reclassified $247 million and $(62) million, respectively, from operating cash flows to investing cash flows relating to changes in restricted cash for continuing and discontinued operations.

(n) Allowance for Doubtful Accounts.

We accrue an allowance for doubtful accounts based on estimates of uncollectible revenues by analyzing counterparty credit ratings, historical collections, accounts receivable agings and other factors. We write-off accounts receivable balances against the allowance for doubtful accounts when we determine a receivable is uncollectible. Write-offs related to refunds for energy sales in California were recorded in revenues (see note 13(a)).

(o) Inventory.

We value inventories used in the production of electricity at the lower of average cost or market.

	December 31,	
	2005	**2004**
	(in millions)	
Materials and supplies, including spare parts	$ 149	$ 137
Coal	63	54
Natural gas	32	25
Heating oil	55	30
Total inventory	$ 299	$ 246

(p) Environmental Costs.

We expense environmental expenditures related to existing conditions that do not have future economic benefit. We capitalize environmental expenditures for which there is a future economic benefit. We record liabilities for expected future costs, on an undiscounted basis, related to environmental assessments and/or remediation when they are probable and can be reasonably estimated. See note 12(b).

(q) Asset Retirement Obligations.

Our asset retirement obligations relate to future costs primarily associated with dismantling power plants and ash disposal site closures. Our asset retirement obligation was $21 million and $15 million as of December 31, 2005 and 2004, respectively.

During 2005, we adopted an accounting interpretation relating to asset retirement obligations. This interpretation clarifies that an asset retirement obligation is unconditional even though uncertainty exists about the timing and/or method of settlement and requires that a liability be recognized if it can be reasonably estimated. Based on this, we (a) recorded a cumulative effect of an accounting change, net of tax, of $1 million ($0.00 per share), (b) increased other long-term liabilities by $2 million and (c) increased property, plant and equipment by $1 million.

The adoption of SFAS No. 143 "Accounting for Asset Retirement Obligations" on January 1, 2003, resulted in a gain of $19 million, $10 million net of tax, or $0.06 per share, as a cumulative effect on an accounting change in our consolidated results of operations for 2003. The gain includes $16 million, $7 million net of tax from our European energy operations, which are reported as discontinued operations.

(r) Repair and Maintenance Costs for Power Generation Assets.

We recognize repair and maintenance costs as incurred. Prior to January 2004, we recognized repair and maintenance costs associated with planned major maintenance under the "accrue-in-advance" method for assets acquired prior to December 31, 1999. Effective January 2004, we began expensing these costs as incurred for all of our assets. As a result of this change, we recognized a cumulative effect of an accounting change resulting in an increase in net income of $7 million, net of tax of $3 million, or $0.02 per share.

(s) Deferred Financing Costs.

We incur costs, which are deferred and amortized over the life of the debt, in connection with obtaining financings. See note 6. Changes in deferred financing costs, classified in other long-term assets are:

	2005	2004	2003
		(in millions)	
Beginning of year	$ 126	$ 143	$ 27
Capitalized	1	61	206
Amortized	(15)	(28)	(35)
Accelerated amortization/write-offs		(50)	(55)
End of year	$ 112	$ 126	$ 143

(3) Related Party Transactions

(a) Equity Contributions/Distributions.

We (a) received non-cash contributions of $7 million during 2005 from and (b) made distributions of $1 million during 2004 to CenterPoint in settlement of certain tax matters. See note 10. We received contributions of $45 million during 2003 from CenterPoint primarily related to the non-cash conversion to equity of certain accounts payable.

(b) Indemnities and Releases.

As part of our separation from CenterPoint, we agreed to indemnify our former parent company for liabilities associated with the business we acquired and relating to our initial public offering. See notes 10 and 11(b).

(4) Intangible Assets

(a) Goodwill.

The following table shows goodwill by segment and the changes:

	Retail Energy	Wholesale Energy	Total
		(in millions)	
As of January 1, 2004	$ 53	$ 430	$ 483
Transfer to discontinued operations[1]		(42)	(42)
As of December 31, 2004	53	388	441
Transfer to discontinued operations[2]		(42)	(42)
Other[3]		(12)	(12)
As of December 31, 2005	$ 53	$ 334	$ 387

(1) Goodwill related to our Orion Power Holdings, Inc. (Orion Power Holdings) and its subsidiaries (Orion Power) hydropower plants. See note 20.

(2) Goodwill related to our Ceredo plant and New York plants. See note 20.

(3) Goodwill related to (a) revisions to the Orion Power purchase price allocation for tax matters of $9 million and (b) various asset sales totaling $3 million. See note 19.

As of December 31, 2005 and 2004, we had $72 million and $80 million, respectively, of goodwill that is deductible for United States income tax purposes for future periods.

July 2003 Goodwill Impairment Test Related to our Wholesale Energy Reporting Unit. The July 2003 sale of our Desert Basin plant required us to allocate a portion of the goodwill in the wholesale energy reporting unit to the Desert Basin plant operations on a relative fair value basis in order to compute the loss on disposal. We also tested the recoverability of the remaining goodwill in our wholesale energy reporting unit as of July 2003.

As a result of this test, we recognized an impairment of $985 million (pre-tax and after-tax) in the third quarter of 2003. This impairment was due to a decrease in the estimated fair value primarily attributable to: (a) reduced projected commercialization opportunities related to our power generation assets; (b) the elimination of proprietary trading; (c) lower projected regulatory capacity values due to the lack of development of appropriate market structures and a lower outlook for revenues from existing regulatory capacity markets; (d) reduced long-term margins from our existing portfolio as a result of lowering our estimates of the margins required to induce new capacity to enter the markets; (e) expectations for the retirement and/or mothballing of some of our facilities; (f) lower market and comparable public company values data; and (g) the level of working capital; partially offset by reductions in our projected commercial, operational and support groups costs and lower projected operations and maintenance expense.

Additional Goodwill Impairment Tests. In addition to the July 2003 goodwill impairment test, we performed impairment tests at the following dates: November 2003, May 2004, November 2004, January 2005, March 2005, April 2005, August 2005 and September 2005 due to either asset sales or our annual impairment tests. No impairments were indicated in these tests.

Estimation of our Wholesale Energy Reporting Unit's Fair Value. We estimate the fair value of our wholesale energy reporting unit based on a number of subjective factors, including: (a) appropriate weighting of valuation approaches (income approach, market approach and comparable public company approach), (b) projections about future power generation margins, (c) estimates of our future cost structure, (d) discount rates for our estimated cash flows, (e) selection of peer group companies for the

public company approach, (f) required level of working capital, (g) assumed terminal value and (h) time horizon of cash flow forecasts.

Management has determined the fair value of our wholesale energy reporting unit with the assistance of an independent appraiser. In determining the fair value of our wholesale energy reporting unit, we made the following key assumptions: (a) the markets in which we operate will continue to be deregulated; (b) there will be a recovery in electricity margins over time such that companies building new generation facilities can earn a reasonable rate of return on their investment and (c) the economics of future construction of new generation facilities will likely be driven by integrated utilities. As part of our process, we modeled all of our power generation facilities and those of others in the regions in which we operate. Our assumptions for each of our goodwill impairment tests during 2003, 2004 and 2005 were:

Number of years used in internal cash flow analysis	15
EBITDA[1] multiple for terminal values (for September 2005 test)	8.0
EBITDA[1] multiple for terminal values (through August 2005 test)	7.5
Risk-adjusted discount rate for our estimated cash flows	9.0%
Approximate average anticipated growth rate for demand in power	2.0%
Long-term after-tax return on investment for new investment	7.5%

(1) Defined as earnings (loss) before interest expense, interest income, income taxes, depreciation and amortization expenses.

(b) Other Intangibles.

	Remaining Weighted Average Amortization Period (Years)	December 31, 2005 Carrying Amount	December 31, 2005 Accumulated Amortization	December 31, 2004 Carrying Amount	December 31, 2004 Accumulated Amortization
		(in millions)			
SO_2 emission allowances[1][2]	[1]	$ 371	$ (179)	$ 298	$ (118)
NO_x emission allowances[1][3]	[1]	344	(147)	351	(117)
Contractual rights[4]	1	4	(3)	4	(3)
Power generation site permits[5]	30	73	(7)	73	(5)
Water rights[5]	30	67	(12)	67	(10)
Other[5]		3	(3)	3	(2)
Total		$ 862	$ (351)	$ 796	$ (255)

(1) SO_2 is sulfur dioxide and NO_x is nitrogen oxide. Amortized to amortization expense on a units-of-production basis. As of December 31, 2005, we have recorded (a) SO_2 emission allowances through the 2039 vintage year and (b) NO_x emission allowances through the 2039 vintage year.

(2) During 2005, 2004 and 2003, we purchased $130 million, $61 million and $43 million of SO_2 emission allowances, respectively. See note 19 for sales.

(3) During 2005, 2004 and 2003, we purchased $16 million, $64 million and $33 million of NO_x emission allowances, respectively. See note 19 for sales.

(4) Amortized to revenues and fuel expense, as applicable, based on the estimated realization of the fair value established on the acquisition date over the contractual lives.

(5)

Amortized to amortization expense on a straight-line basis over the estimated lives.

Amortization expense consists of:

	2005	2004	2003
		(in millions)	
Other intangibles, excluding contractual rights and obligations[1][2]	$ 95	$ 81	$ 55
Contractual rights	$ (1)	$ (1)	$ (1)
Contractual obligations[1]	9	30	28
Net	$ 8	$ 29	$ 27

(1) Contractual obligations are in other long-term liabilities.

(2) Includes amortization of emission allowances of $90 million, $77 million and $50 million during 2005, 2004 and 2003, respectively.

Estimated amortization expense, based on our intangibles as of December 31, 2005, excluding contractual rights and obligations, for the next five years is (in millions):

2006	$ 40
2007	23
2008	13
2009	15
2010	16

(5) Derivatives and Hedging Activities

We use derivative instruments to manage operational or market constraints, to increase return on our generation assets and to execute our retail energy segment's supply procurement strategy. The instruments used are fixed-price derivative contracts to hedge the variability in future cash flows from forecasted sales of power and purchases of fuel and power. Our objective in entering into these fixed-price derivatives is to fix the price for a portion of these transactions. See note 2(d).

Our derivative portfolio, excluding cash flow hedges, is $308 million (net liability) and $114 million (net liability) as of December 31, 2005 and 2004, respectively. Our cash flow hedges are valued at $471 million (net liability) and $21 million (net liability) as of December 31, 2005 and 2004, respectively.

As of December 31, 2005 and 2004, the maximum length of time we are hedging our exposure to the variability in future cash flows that may result from changes in commodity prices is seven years and eight years, respectively. As of December 31, 2005, $115 million of accumulated other comprehensive loss is expected to be reclassified into our results of operations during the next 12 months. However, the actual amount reclassified into earnings could vary from the amounts recorded as of December 31, 2005, due to future changes in market prices.

Although we discontinued our proprietary trading business in March 2003, we have legacy positions, which will be closed as economically feasible or in accordance with their terms. The margins associated with these transactions are (income (loss)):

	2005	2004	2003
		(in millions)	
Revenues	$ (15)	$	$ (14)
Purchased power, fuel and cost of gas sold	(30)	4[(1)]	(35)[(1)]
Gross margin	$ (45)	$ 4	$ (49)

(1) Beginning in 2005, amounts were reclassified from revenues to purchased power, fuel and cost of gas sold based on commodity type.

The income (loss) of our energy and interest rate derivative instruments is:

	2005	2004	2003
		(in millions)	
Energy derivatives:			
Hedge ineffectiveness	$ 71	$ (17)	$ (18)
Other net unrealized gains (losses)	(263)	(207)	(30)
Interest rate derivatives:			
Hedge ineffectiveness			(2)
Other net unrealized gains (losses)	(16)	(24)	(9)
Total[(1)(2)]	$ (208)	$ (248)	$ (59)

(1) No component of the derivatives' gain or loss was excluded from the assessment of effectiveness.

(2) Includes $0, $16 million gain and $0 for 2005, 2004 and 2003, respectively, recognized in our results of continuing operations as a result of the discontinuance of cash flow hedges for forecasted transactions that we determined were probable of not occurring.

For a discussion of our interest rate derivatives, see note 6(e).

(6) Debt

(a) Overview.

As of December 31, 2005, we were in compliance with all of our debt covenants. Our outstanding debt is:

	December 31,					
	2005			2004		
	Weighted Average Stated Interest Rate[(1)]	Long-term	Current	Weighted Average Stated Interest Rate[(1)]	Long-term	Current
	(in millions, except interest rates)					
Facilities, Bonds and Notes:						
Reliant Energy:						
Senior secured revolver due 2009	8.40%	$ 383	$	7.13%	$ 199	$
Senior secured term loans (B1) due 2010[(2)]	6.09	240	313	4.80	652	10
Senior secured term loans (B2) due 2010	6.91	296	3			
Senior secured notes due 2010	9.25	550		9.25	550	
Senior secured notes due 2013	9.50	550		9.50	550	
Senior secured notes due 2014	6.75	750		6.75	750	
Convertible senior subordinated notes due 2010 (unsecured)	5.00	275		5.00	275	
Subsidiary Obligations:						
Orion Power Holdings senior notes due 2010 (unsecured)	12.00	400		12.00	400	
PEDFA fixed-rate bonds for new Seward plant due 2036	6.75	500		6.75	500	
REMA term loans (unsecured)				4.94	14	14
Reliant Energy Channelview, L.P.:						
Term loans and revolving working capital facility:						
Floating rate debt due 2006 to 2024	6.04	259	14	3.83		284
Fixed rate debt due 2014 to 2024	9.55	75		9.55		75
RE Retail Receivables, LLC facility due 2006	4.71		450	3.90		227
Total facilities, bonds and notes		4,278	780		3,890	610
Other:						
Adjustment to fair value of debt[(3)]		39	9		49	8
Adjustment to fair value of debt due to warrants and other						1
Total other debt		39	9		49	9
Total debt		$ 4,317	$ 789		$ 3,939	$ 619

(1) The weighted average stated interest rates are for borrowings outstanding as of December 31, 2005 or 2004.

(2) As of December 31, 2005 and 2004, we classified $638 million as discontinued operations. See note 20.

(3)

Debt and interest rate swaps acquired in the Orion Power acquisition were adjusted to fair market value as of the acquisition date. Included in interest expense is amortization of $9 million, $9 million and $8 million for valuation adjustments for debt for 2005, 2004 and 2003, respectively.

Amounts borrowed and available for borrowing under our revolving credit agreement as of December 31, 2005 are:

	Total Committed Credit	Drawn Amount	Letters of Credit	Unused Amount
	(in millions)			
Reliant Energy senior secured revolver due 2009	$ 1,700	$ 383	$ 937	$ 380
Reliant Energy Channelview, LP revolving working capital facility due 2007	14			14
	$ 1,714	$ 383	$ 937	$ 394

Debt maturities as of December 31, 2005 are (in millions):

2006	$	480
2007		31
2008		33
2009		419
2010		2,035[(1)]
2011 and thereafter		2,060
	$	5,058

(1) Includes $300 million classified as current that we plan to pay down with net proceeds from sale of New York plants. See note 20.

(b) Outstanding Debt.

Senior Secured Term Loans and Senior Secured Revolver. Our term loan B1 bears interest at London Inter Bank Offering Rate (LIBOR) plus 2.375% or a base rate plus 1.375%. Our $1.7 billion revolving credit facility bears interest at LIBOR plus 2.875% or a base rate plus 1.875% and provides for the issuance of up to $1.4 billion of letters of credit. We must prepay this revolving credit facility and term loan B1 (the December 2004 credit facilities) with proceeds from certain asset sales and issuances of equity securities. Additionally, we must make quarterly principal payments of 0.25% of the original principal amount of the term loans.

Subject to certain exceptions, the December 2004 credit facilities restrict our ability to, among other actions, (a) encumber our assets, (b) enter into business combinations or divest our assets, (c) incur additional debt or engage in sale and leaseback transactions, (d) pay dividends or prepay other debt, (e) make investments or acquisitions, (f) enter into transactions with affiliates, (g) make capital expenditures, (h) materially change our business, (i) amend our debt agreements, (j) repurchase our capital stock and (k) engage in certain types of trading activities. In addition, we are required to achieve specified levels for the ratios of (a) adjusted net debt to adjusted net earnings (loss) before interest expense, interest income, income taxes, depreciation, amortization and certain lease expenses (EBITDAR) (consolidated leverage ratio) and (b) adjusted consolidated EBITDAR to adjusted interest expense (consolidated interest coverage ratio)

The specified level for each ratio is:

Four Fiscal Quarters Ending	Maximum Consolidated Leverage Ratio
December 31, 2005 through September 30, 2006	6.0:1.0
December 31, 2006 through September 30, 2007	5.5:1.0
December 31, 2007 and each fiscal quarter thereafter	5.0:1.0

Four Fiscal Quarters Ending	Minimum Consolidated Interest Coverage Ratio
December 31, 2005	1.8:1.0
March 31, 2006 through December 31, 2006	1.5:1.0[(1)]
March 31, 2007 through September 30, 2007	1.8:1.0
December 31, 2007 and each fiscal quarter thereafter	2.0:1.0

(1) The Minimum Consolidated Interest Coverage Ratio was amended in December 2005. Additionally, the amendment requires us to use the net unrestricted sales proceeds from our Ceredo and New York plants to prepay, subject to our indentures, the December 2004 term loan.

Certain of our subsidiaries jointly and severally guarantee the December 2004 credit facilities, which are also secured by security interests in assets of our guarantor subsidiaries and the capital stock of some operating subsidiaries. See note 15.

October 2005 Senior Secured Term Loans. In October 2005, we borrowed $299 million in term loans (B2) (the October 2005 credit facility), which bear the same interest rate spreads as the term loan B1. The material terms of the October 2005 credit facility are substantially identical to those of the December 2004 credit facilities discussed above. The collateral that secures the December 2004 credit facilities also secures the October 2005 credit facility except for the capital stock of some of our subsidiaries and certain cash collateral.

If we (a) achieve certain financial ratios for two consecutive fiscal quarters, (b) repay the B1 and B2 term loans in full and (c) are not in default under the December 2004 credit facilities, the revolving credit facility will become unsecured and several covenants will be suspended. We do not expect to satisfy these conditions in 2006.

Senior Secured Notes. The collateral that secures the October 2005 credit facility also secures the senior secured notes. The senior secured notes have covenants similar to those in our credit facilities. If the December 2004 revolving credit facilities become unsecured, the senior secured notes will become unsecured. In addition, certain covenants under the senior secured notes will be suspended in the event we achieve certain investment grade credit ratings.

Convertible Senior Subordinated Notes. These notes are convertible into shares of our common stock at a conversion price of $9.54 per share. We may redeem the notes, in whole or in part, at any time on or after August 20, 2008, if the last reported sales price of our common stock is at least 125% of the conversion price then in effect for a specified period of time.

Orion Power Holdings Senior Notes. These notes were recorded at a fair value of $479 million upon the acquisition of Orion Power. The $79 million premium is being amortized to interest expense over the life of the notes. The senior notes are senior unsecured obligations of Orion Power Holdings, are not guaranteed by any of Orion Power Holdings' subsidiaries and are non-recourse to Reliant Energy. The senior notes have covenants that restrict (subject to certain exceptions) the ability of Orion Power Holdings and certain of its subsidiaries to, among other actions, (a) pay dividends, (b) incur

indebtedness or issue preferred stock, (c) make investments, (d) divest assets, (e) encumber its assets, (f) enter into transactions with affiliates, (g) engage in unrelated businesses and (h) engage in sale and leaseback transactions. As of December 31, 2005, conditions under these covenants have been met that allow the payment of dividends. However, we expect that after the closing of the sale of the New York plants, which occurred in February 2006, Orion Power Holdings' dividends to Reliant Energy may be partially restricted.

PEDFA Bonds for New Seward Plant. Reliant Energy Seward, LLC (Seward) partially financed the construction of its power plant with proceeds from the issuance of tax-exempt revenue bonds by Pennsylvania Economic Development Financing Authority (PEDFA), which are guaranteed by Reliant Energy.

Reliant Energy Channelview, L.P. Reliant Energy Channelview, L.P. (Channelview) entered into a credit agreement that financed the construction of a power plant. The credit agreement consists of (a) $369 million in term loans and (b) $14 million revolving working capital facility that matures in 2007.

With the exception of a fixed-rate tranche (9.55% for $75 million), the loans bear a floating interest rate based either on LIBOR or base rates plus a margin that increases over time. The facility is secured by substantially all of the assets of Channelview and is non-recourse to Reliant Energy. The facility prohibits Channelview from taking certain actions (subject to exceptions), including paying dividends or making restricted payments unless, among other things, it maintains specified debt service coverage ratios and debt service account balances. As of December 31, 2005, the conditions under these covenants were not met. Channelview is not expected to satisfy these conditions in 2006. We have obtained waivers from the lenders regarding insurance requirements specified in the credit agreement and plan to do so in the future. The current waiver expires in April 2006. Prior to the expiration of this waiver, Channelview intends to obtain a successor waiver or purchase an insurance policy that will conform with the credit agreement.

RE Retail Receivables, LLC Facility. We have a receivables facility arrangement to sell an undivided interest in accounts receivable from our retail business to financial institutions on an ongoing basis. We amended this arrangement in September 2005 to extend its maturity until September 2006, reduce the fees we are charged, increase the proportion of receivables against which we can borrow and increase the maximum capacity available from $350 million to $450 million.

The assets of the special purpose subsidiary that purchases the receivables and then resells receivables under the facility are available first and foremost to satisfy the claims of its creditors. The special purpose subsidiary is a separate entity.

Prior to September 28, 2004, these transactions were accounted for as sales of receivables; as a result, the related receivables and debt were excluded from our consolidated balance sheet. Effective with the September 28, 2004 amendment to this facility, the qualified special purpose entity (QSPE) ceased to be a QSPE and we began consolidating its results of operations and the proceeds from receivables sold to the financial institutions were treated as a financing. As a result, accounts receivable and short-term borrowings of $350 million were included in the consolidated balance sheet as of the amendment date. The borrowings under the facility bear interest at floating rates that include fees based on the facility's level of commitment and utilization. We service the receivables and received a fee of 0.4%, 0.4% and 0.5% of cash collected during 2005, 2004 and 2003, respectively, which approximates our actual service costs. Reliant Energy also guarantees the performance obligations of the originators of the receivables and the servicing of the receivables. The guarantee contains, among other covenants, financial covenants identical to those contained in our December 2004 and October 2005 credit facilities.

(c) Refinanced or Repaid Historical Debt.

2004 Financing Activity. In December 2004, we completed a $4.25 billion refinancing, the components of which included:

New debt:

- $1.7 billion revolving credit facility due 2009,
- $1.3 billion term loan due 2010,
- $750 million of senior secured notes due 2014 and
- $100 million of fixed-rate tax-exempt PEDFA bonds (in addition to $400 million of floating-rate tax-exempt revenue bonds which were converted to fixed-rate bonds).

Retired debt:

- $2.1 billion revolving credit facility due 2007,
- $1.7 billion term loan due 2007 and
- $255 million of Orion Power MidWest, L.P. (Orion MidWest) debt and associated interest rate swap agreements due 2005.

REMA Term Loans. R