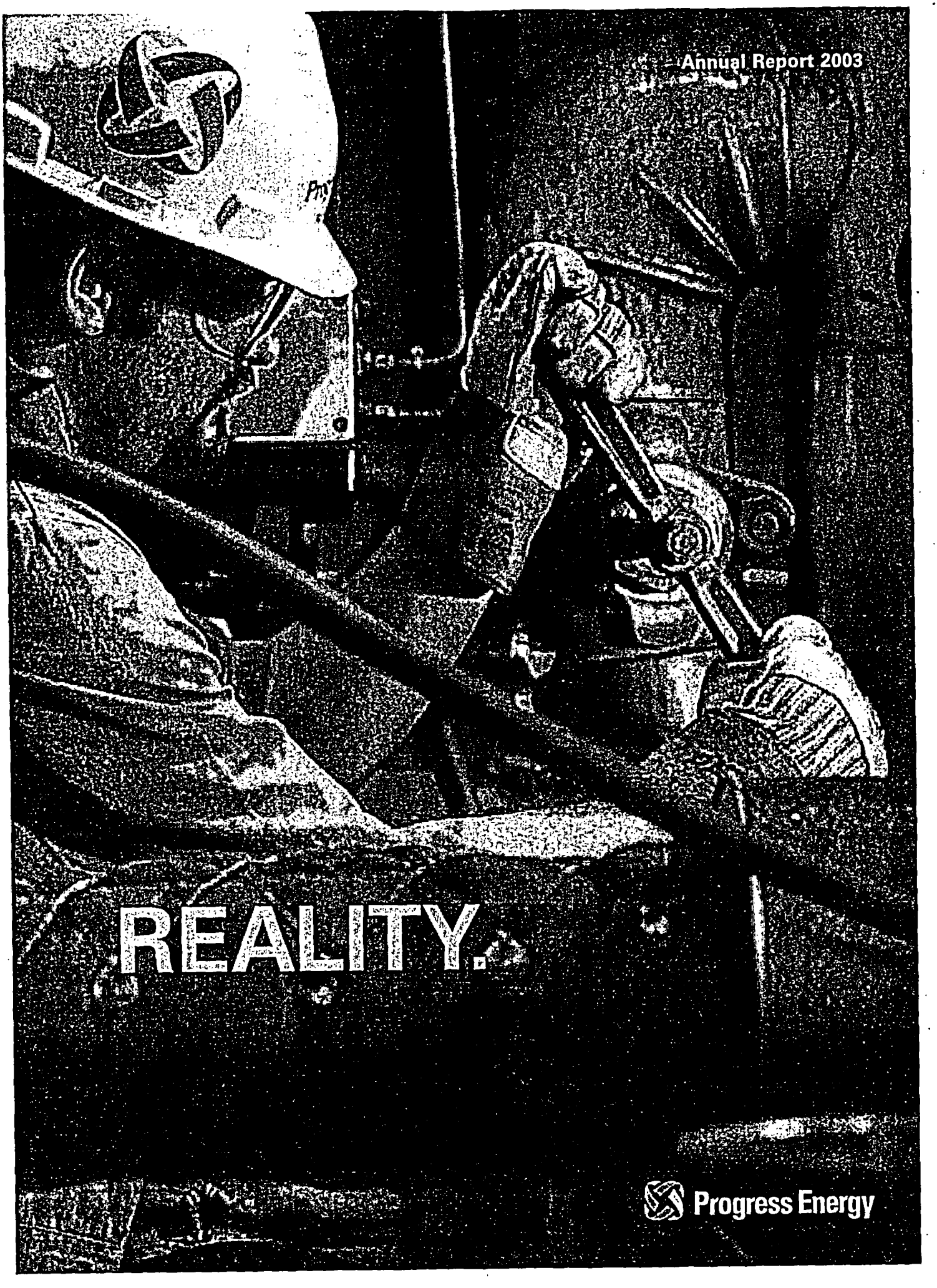

Annual Report 2003
REALITY.
Progress Energy

FINANCIAL HIGHLIGHTS

Years ended December 31 *(in millions, except per share data)*	2003	2002	2001
Financial Data			
Operating revenues	$8,743	$8,091	$8,129
Net income	782	528	542
Income from continuing operations	811	552	541
Ongoing earnings per common share*	3.56	3.81	3.40
Reported GAAP earnings per common share	3.30	2.43	2.65
Average common shares outstanding	237	217	205
Common Stock Data			
Return on average common stock equity (percent)	11.07	8.44	9.41
Book value per common share	$30.94	$28.73	$28.20
Market value per common share (closing)	$45.26	$43.35	$45.03

** See page 95 for a reconciliation of ongoing earnings per share to reported GAAP earnings per share.*

REALITY.
THE RIGHT CONTEXT FOR BUSINESS.

At Progress Energy, we take a realistic approach to our business. That means we recognize opportunities and risks for what they are, not what we wish they were. And we act accordingly — mindful of the best interests of our customers, employees and shareholders. It's a course that keeps us grounded in reality, which, in today's turbulent business environment, is the only place to be.

LETTER TO SHAREHOLDERS

Fellow Shareholders:

Progress Energy had a successful 2003 by carrying out a sound business strategy with operational skill and financial discipline. We also dealt effectively with the reality of change and challenge.

While many energy companies have been trying to recover from broken trust and failed initiatives, our company continues to build on its record of integrity, operational excellence and relentless improvement.

We set our standards high, focus on the fundamentals and carefully balance opportunity and risk. When we have a setback, we learn from it. This pragmatic, performance-oriented approach enables us to deliver value to shareholders while providing dependable service to customers.

Our Strategy

Progress Energy is an integrated energy company focused on the end-use electricity markets. This means we both generate and deliver power to retail customers as well as load-serving wholesale customers.

Financial Objectives and Results

Our financial objectives are straightforward:

- reward shareholders with a growing dividend
- provide earnings growth that positions the company in the upper half of our industry
- live within our means
- strengthen the balance sheet
- maintain ready access to credit markets
- communicate clear, comprehensive and timely financial information

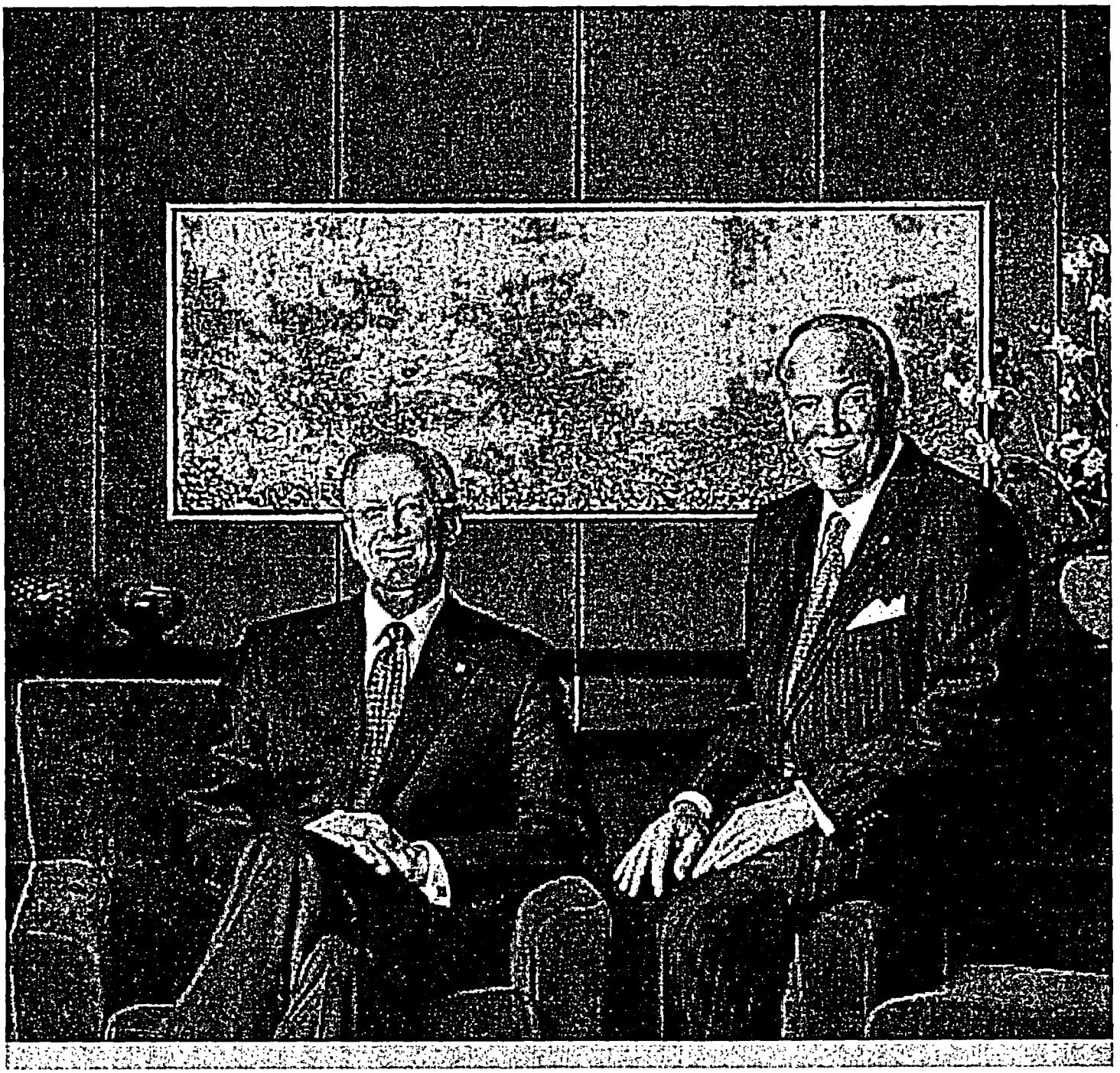
In December 2003 we approved an annual dividend increase of six cents to $2.30 per share. That's 16 straight years of increases. Our 2003 total return to shareholders (stock appreciation plus dividends) was 10 percent, and it has averaged 9.9 percent a year over the past 10 years.

In 2003 we improved our balance sheet by reducing our debt-to-capitalization ratio to below 59 percent, down from 65 percent right after the 2000 merger that formed Progress Energy. We intend to reduce it to about 57 percent in 2004.

We maintained our investment-grade credit ratings, even though Moody's and Standard & Poor's lowered the ratings one notch. These same rating agencies upgraded our outlook to "stable."

Progress Energy delivered strong earnings in 2003. Our employees deserve credit for finding ways to cut expenses while improving operational performance.

One issue affecting our earnings and stock price is the eligibility of our synthetic-fuel facilities to continue earning federal tax credits. In late 2003 we successfully resolved some aspects of this complex issue and are working diligently to complete the tax audits of all the facilities.



Robert B. McGehee, left, and William Cavanaugh III

Our Two Electric Utilities

The solid foundation of our business is our two regulated electric utilities:

- Progress Energy Carolinas serves 1.3 million customers in North Carolina and South Carolina.
- Progress Energy Florida serves 1.5 million customers in Florida.

Our utilities are well positioned to meet our customers' future energy needs while providing reliable service at competitive prices.

An important strength of our two utilities is that they serve an expanding customer base — 59,000 new customers were added in 2003. Although growth continues in the residential and commercial sectors, manufacturing in the Carolinas has declined in recent years — but we believe this trend will begin to reverse itself.

Progress Energy is a leader in partnering with state and local governments to attract new businesses that provide additional revenue for our utilities and good jobs for our fellow citizens. The November 2003 *Site Selection* magazine recognized North Carolina for having the best business climate in the nation for the third consecutive year. South Carolina and Florida are also ranked in the top ten. The magazine named Progress Energy as one of the top utilities in economic development.

Our utilities had many accomplishments during 2003, including:

- Achieved outstanding performance at our diverse mix of power plants. Our nuclear fleet set an all-time generation record while maintaining high safety standards and one of the lowest-cost operations in the nation. Our fossil plants also performed very well and are setting the industry standard for cost-efficient installation of emission controls.
- Invested more than $1 billion in power supply and delivery infrastructure, which will help us meet the growing demand for energy in our service areas.
- Earned top-quartile ranking in the J.D. Power customer-satisfaction surveys of our residential and small-business customers.
- Provided quick service restoration after two ice storms and Hurricane Isabel in the Carolinas, and we earned our industry's emergency response award for the fourth time in six years.
- Helped launch North Carolina's GreenPower Program, an innovative statewide effort to promote renewable-energy generation.

Progress Ventures

Progress Ventures is our business unit that competes in wholesale energy markets in the Eastern U.S. It owns 3,100 megawatts of electric generating capacity in the Southeast and 360 billion cubic feet equivalent of proven natural gas and oil reserves in Texas and Louisiana. It also owns river terminals in the Ohio River Valley and coal mines in Central Appalachia.

The returns generated by Progress Ventures supplement the steady net income from our two regulated electric utilities.

These are just a few of the noteworthy events at Progress Ventures in 2003:

- Completed building our 3,100-megawatt fleet of nonregulated plants and secured contracts for 85 percent of this generation capacity for 2004.
- Signed new and renewed wholesale power contracts and had a banner year in selling electricity to other regions of the country.
- Doubled our natural gas reserves by developing our existing properties and adding to our holdings in Texas and Louisiana. These gas wells provide financial protection against higher fuel prices for our nonregulated power plants that burn gas.

People Lead the Way

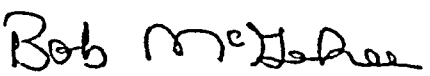
The caliber of our employees and our dedication to making the most of their potential are central to our success. We aim to attract and retain the best employees, fully engage their diverse talents and continually develop their knowledge and skills.

Since the merger that formed Progress Energy, we've been systematically building an organizational culture based on people, performance and excellence. Cultivating individual abilities and shared values gives us an edge in adapting to an industry and world in constant flux.

Rigorous succession planning and development efforts have created a deep, talented leadership team second to none in the industry. This depth goes beyond job titles. In a very real way, we have become a company of leaders.

Progress Energy is well prepared to earn your trust and confidence for many years to come. That's a responsibility we take seriously and a reality you can embrace.

William Cavanaugh III
Chairman

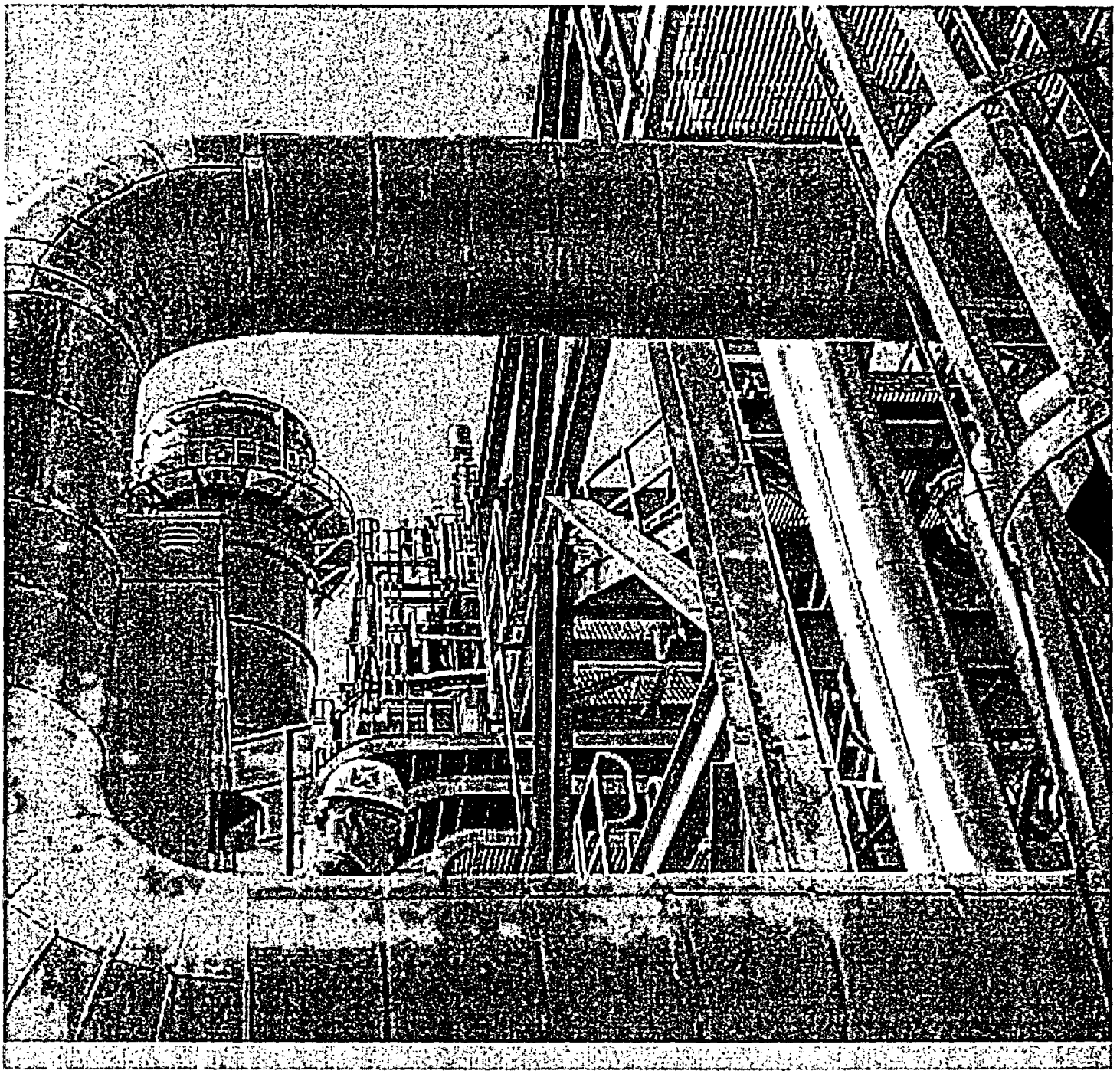


Robert B. McGehee
President and Chief Executive Officer

A NOTE FROM BILL CAVANAUGH: On January 23, 2004, I announced my decision to retire as CEO on March 1 of this year and as chairman in May. As my successor, Bob McGehee will provide outstanding leadership and will take Progress Energy to even higher levels of performance. Bob has been a senior executive with the company since 1997 and has the background and experience to continue its success. It has been an honor to serve this great company, and I'm grateful for the support given me by so many people over the years.

THE REAL STORY.

Telling it like it is. At Progress Energy, we start with the basics. Our sound growth strategy focuses on the fundamental strengths of our core business: energy generation and delivery. Of course, we've also taken other important paths, like the competitive wholesale energy market. Here, we've made smart investments to balance our assets with the needs of the marketplace. We manage our overall business well, and we continue to raise our performance to improve our support of the customers and communities we serve. That's our reality. And we'll continue to build on it.



Hines Energy Complex, Polk County, FL.

REAL INSIGHT.

We don't ignore the realities of our industry — we make the most of them.

An evolving economic base in our territories, unpredictable weather and overcapacity in wholesale generation — market realities like these affect our business every day. Yet, we don't see them as limitations. Combined with Progress Energy's expertise in risk management, economic forecasting and fuel portfolio management, they become guideposts for charting a more positive course — one that has outperformed the S&P 500 for the past 10 years and the S&P Electric Companies for shareholder return over the past five years.

Our direction in 2003 was to continue strengthening our core utility business. We invested more than $1 billion during the year to reinforce the reliability of our power supply and delivery infrastructure in Florida and the Carolinas. We added more than 2,000 megawatts to our regulated and unregulated generation capacity, including a 516-megawatt, natural-gas-fueled addition at our Hines Energy Complex in Polk County, Florida. On the nonregulated side of our business, we focused on strategic growth. In Georgia, for example, we added significantly to our load-serving portfolio through power supply agreements with Jackson Electric Membership Corp. and Morgan Stanley Capital Group, Inc. And to ensure a stable supply of fuel for the next 10 years, we doubled the size of our natural gas reserves held in Texas and Louisiana, acquiring approximately 200 producing natural gas wells and tripling net income from our gas assets.

We also strengthened another facet of Progress Energy — our unabated passion for operational excellence. It drives all we do, from our emergency storm response (we again won the Edison Electric Institute's Emergency Response Award) to our nuclear fleet (our nuclear power plants again set new performance records for power generation). Our reality improves every day.

REAL LIFE.

Strong communities are the foundation of our core business — and a changing reality.

Progress Energy generates and delivers electric power to more than 2.8 million customers in communities in Florida and the Carolinas. Our markets continue to expand, growing by about 59,000 new households a year. But the demographics are changing. For instance, the number of Spanish-speaking customers Progress Energy serves has more than doubled in the past two years. In response, we've added Spanish-speaking phone operators, translated our customer correspondence and signage and included a Spanish language option on our automated customer service line.

At Progress Energy, we connect to the communities we serve through a variety of community development and educational initiatives. Through the Progress Energy Foundation, the philanthropic arm of Progress Energy, we support organizations and programs that focus on improving the quality of life in the communities where our employees and customers live and work.

For example, in Florida we provided funding for one of NASA's Challenger Learning Centers. Its purpose: to encourage middle-school students to pursue science and math studies. And in collaboration with the Public School Forum of North Carolina, we created the Progress Energy Leadership Institute. Now in its second two-year session, the institute puts new school administrators on the fast track to becoming strong educational and community leaders by teaching them to apply best business practices in their schools. We're opening minds to new realities.

Phyllis Farren, principal — graduate of the Progress Energy Leadership Institute.

Restored watershed, Polk County, FL.

REAL COMMITMENT.

We're focused on the environment — it's a reality we want to protect.

Our service territories span three states and 54,000 square miles. That makes us stewards of a vast array of natural resources. It's a mission we take very seriously; environmental responsibility is a core value of our company. In 2003, we increased our commitment further by strengthening our environmental policies, documentation procedures and risk-assessment guidelines. The majority of our environmental initiatives for air and water quality are works in progress, and we continue to build on them.

The North Carolina Clean Smokestacks Act — landmark clean-air legislation championed by Progress Energy and passed in 2002 — is a case in point. To meet its requirements, we plan to invest more than $800 million at our North Carolina fossil-fuel plants by 2013. The result will be a 56 percent reduction in nitrogen oxide and a 74 percent reduction in sulfur dioxide emissions from 2001 levels. Currently we are ahead of the industry in implementing changes. We also continue to underscore our strong commitment to watershed management and wildlife conservation. At our Hines Plant site in Florida, we donated more than 2,000 acres of restored watershed to the state of Florida to protect regional river systems and wildlife habitats.

We are developing innovative ways to link environmental excellence to other parts of our business. Through a proprietary process, we are recycling fly ash from coal-burning plants for use as a manufactured product in concrete and other building and construction materials. In partnership with the Florida Department of Environmental Protection, our leadership in exploring alternative energy sources is taking us into new areas, like hydrogen fuel-cell research, hydrogen production and photovoltaic systems. We're busy turning new ideas into practical realities.

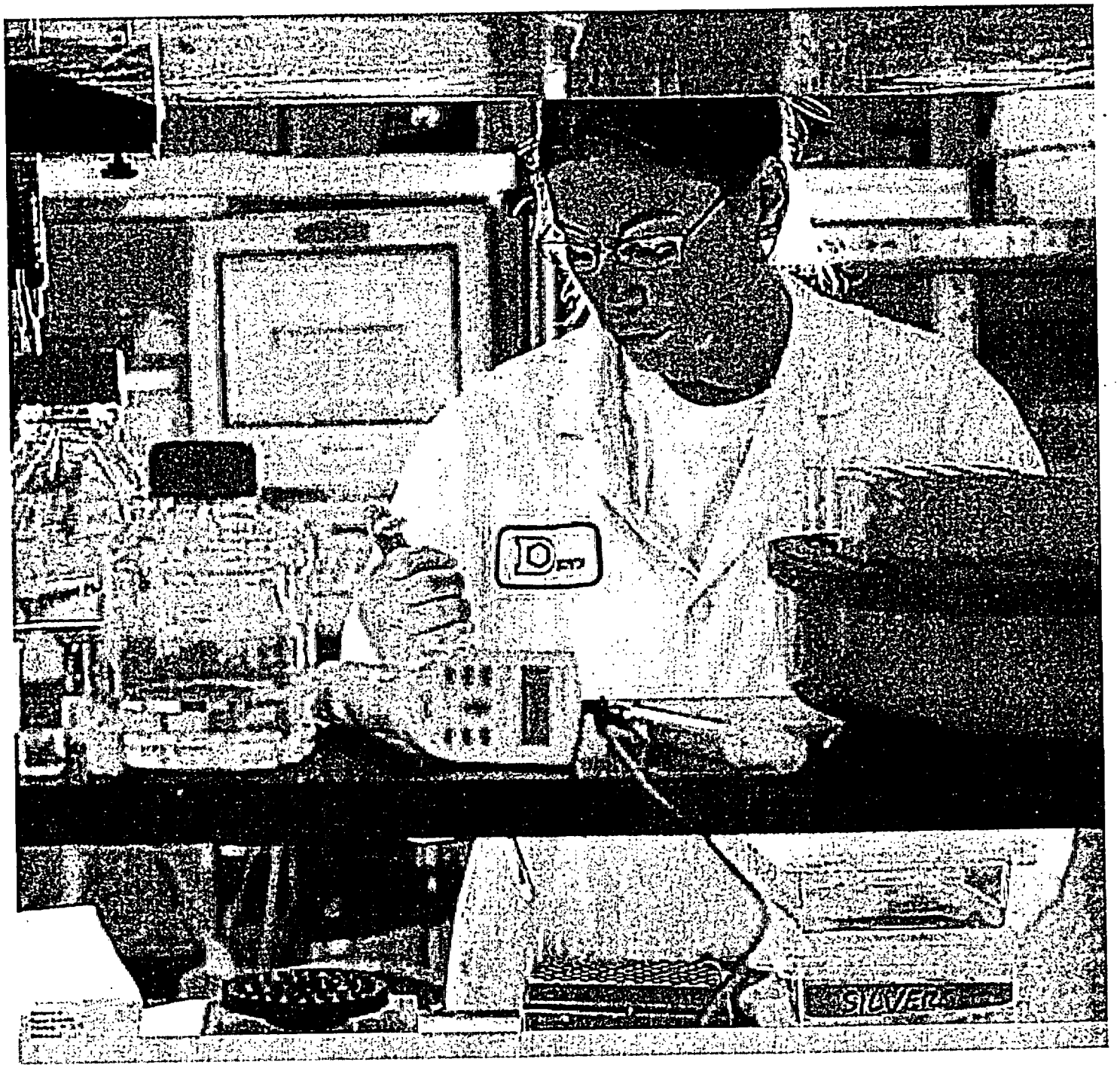
REAL INVESTMENT.

We take a realistic approach to promoting economic development — it's called partnership.

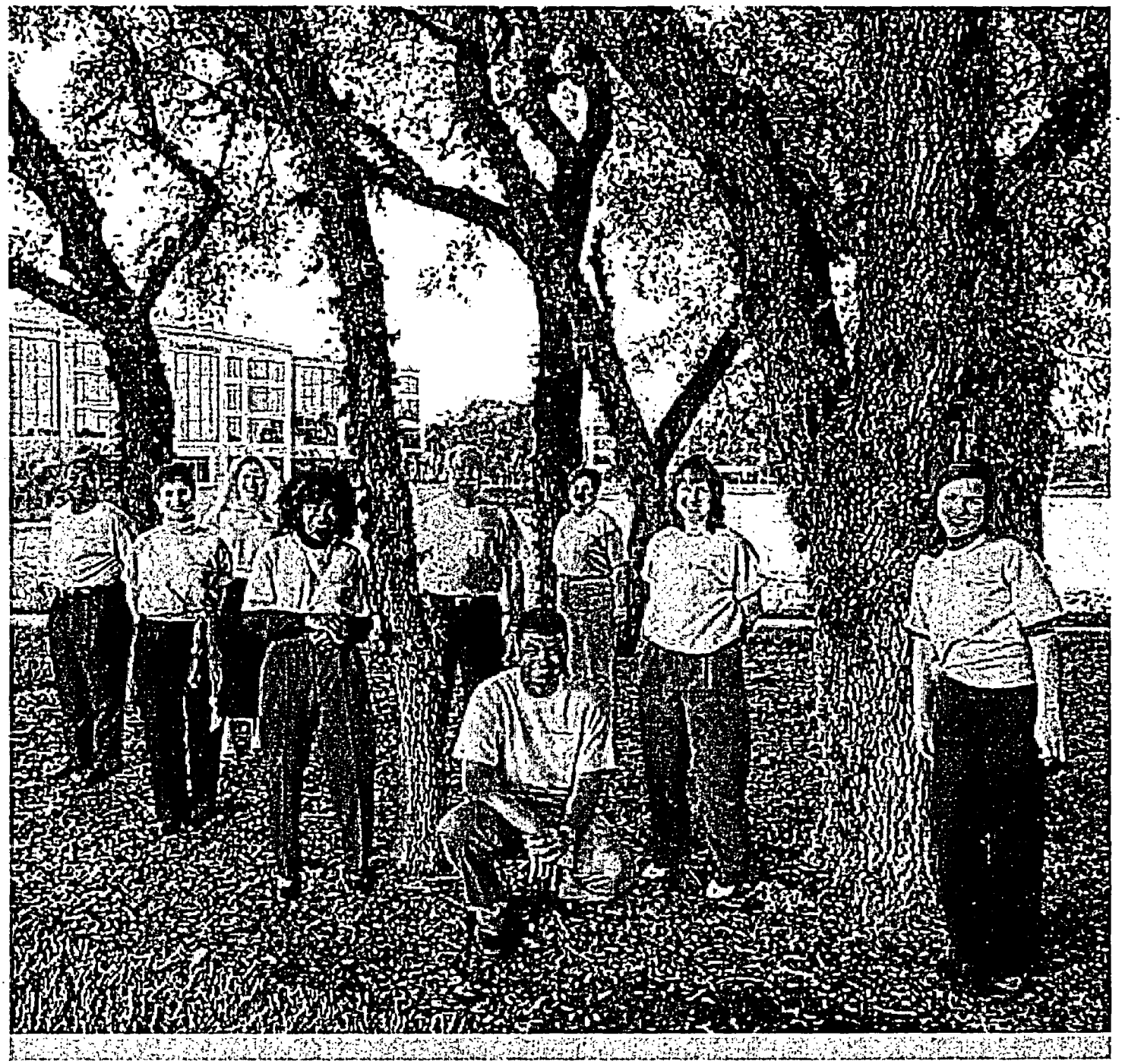
The economic base in our service territories, much like our customer base, is also changing. The traditional manufacturing sector in North Carolina and South Carolina is shifting from textiles and apparel to the next generation of knowledge-based industries. And the slow recovery of our national economy has reduced the pace of commercial growth in both Florida and the Carolinas.

To help spur new growth, Progress Energy plays an active part in recruiting, retaining and expanding industry in our service territories. Our role is to be a contributing part of a successful solution. To make that happen, we partner with state governments, regional and county economic development organizations, universities and community colleges and private enterprise. Together, we identify and help nurture new and emerging industrial sectors. The results for 2003 are encouraging — 9,400 new jobs and $691 million in new capital investment in Florida and the Carolinas. We also had the honor of again being named to *Site Selection* magazine's list of "Top Utilities for Economic Development."

In Florida, we work closely with Enterprise Florida — the public-private partnership responsible for leading Florida's statewide economic development efforts. Bill Habermeyer, Progress Energy Florida's president and CEO, is the partnership's vice chairman. Enterprise Florida works collaboratively with a network of regional and local economic development partners, including Progress Energy, to continually improve Florida's business climate and ensure its global competitiveness. In Raleigh, North Carolina, where our corporate headquarters is located, Progress Energy is active in the revitalization of the downtown area as a civic, commercial and cultural center. We're developing a promising reality for all.



Jennifer Kohm, Diosynth Biotechnology, Cary, NC — an emerging knowledge-based industry.



Progress Energy employee volunteers — National Cancer Society's Relay for Life.

REAL PROGRESS.

People, performance and excellence shape our reality — and our future.

Progress Energy is a company powered by people, driven by performance and committed to excellence. While those words are easy to say, at Progress Energy, they have meaning. They define our organizational culture, which, in turn, defines who we are. More than anything, we are a company of leaders. Our focus is on developing the talent and leadership potential within all Progress Energy employees. One of the ways we do that is through our many diversity and leadership initiatives. GAIN, which stands for growth, action, insight and networking, is a good example. It's a career development program in place at our customer service centers in North Carolina and Florida. Its goal is to help our customer service employees grow to the next level of responsibility. Also helping with leadership development is our mentoring program, which pairs employees with proven company leaders in a one-on-one development opportunity. It began in 2002 and will be expanded in 2004.

Collaboration is a big component of leadership development at Progress Energy — affecting everything from diversity training, to our exemplary storm response, to volunteerism in the community. Once a year, hundreds of Progress Energy employees, from frontline workers to our chief executive officer, volunteer at nonprofit agencies throughout our service territory to help kick off our annual workplace giving campaign, which last year raised $2.3 million.

At Progress Energy, we deal with many realities. The reality of a strong core business. The reality of a growing yet changing customer base. The reality of new opportunities in our regulated and nonregulated markets. The reality of new industries in the Carolinas. The reality of our 15,000 employees, dedicated to continuous improvement. The reality of giving back to the communities we serve. The reality of an environment that needs our protection. And most of all, the reality of Progress Energy's bright and expanding future.

BOARD OF DIRECTORS

Edwin B. Borden
Retired President,
The Borden Manufacturing Co.
(textile management services)
Goldsboro, NC

Elected to the board in 1985 and sits on the following committees: Corporate Governance Committee, Organization and Compensation Committee and Operations, Environmental, Health and Safety Issues Committee.

James E. Bostic, Jr.
Executive Vice President,
Georgia-Pacific Corp.
(manufacturer and distributor of tissue paper, pulp, packaging, building products and related chemicals)
Atlanta, GA

Elected to the board in 2002 and sits on the following committees: Audit and Corporate Performance Committee and Operations, Environmental, Health and Safety Issues Committee.

David L. Burner
Retired Chairman and Chief Executive Officer, Goodrich Corp. (aerospace components, systems and services)
Charlotte, NC

Elected to the board in 1999 and sits on the following committees: Audit and Corporate Performance Committee and Finance Committee.

William Cavanaugh III
Chairman,
Progress Energy, Inc.
Raleigh, NC

Elected to the board in 1993. Serves as chairman, Progress Energy Service Company, LLC and chairman, Progress Energy Ventures, Inc.

Charles W. Coker
Chairman, Sonoco Products Co.
(manufacturer of paperboard and paper and plastic packaging products)
Hartsville, SC

Elected to the board in 1975 and sits on the following committees: Corporate Governance Committee, Organization and Compensation Committee and Finance Committee.

Richard L. Daugherty
Formerly Executive Director, NCSU Research Corp., Vice President, IBM PC Company and Senior State Executive, IBM Corp.
Raleigh, NC

Elected to the board in 1992 and sits on the following committees: Audit and Corporate Performance Committee and Operations, Environmental, Health and Safety Issues Committee.

W. D. "Bill" Frederick, Jr.
Citrus grower and rancher, formerly mayor of Orlando and partner in the law firm of Holland & Knight
Orlando, FL

Elected to the board in 2000 and sits on the following committees: Audit and Corporate Performance Committee and Operations, Environmental, Health and Safety Issues Committee.

William O. McCoy
Partner, Franklin Street Partners (investment management), *formerly Vice Chairman of the Board, BellSouth Corp. and President and Chief Executive Officer, BellSouth Enterprises*
Chapel Hill, NC

Elected to the board in 1996 and sits on the following committees: Organization and Compensation Committee and Finance Committee.

E. Marie McKee
Senior Vice President, Corning, Inc. (developer of technologies for glass, ceramics, fiber optics and photonics) *and President and Chief Executive Officer, Steuben Glass*
Corning, NY

Elected to the board in 1999 and sits on the following committees: Organization and Compensation Committee and Operations, Environmental, Health and Safety Issues Committee.

John H. Mullin, III
Chairman, Ridgeway Farm, LLC (farming and timber management) *and formerly a Managing Director, Dillon, Read & Co.* (investment bankers)
Brookneal, VA

Elected to the board in 1999 and sits on the following committees: Corporate Governance Committee, Audit and Corporate Performance Committee and Finance Committee.

Richard A. Nunis
President, New Business Solutions, Inc. and Retired Chairman, Walt Disney Parks & Resorts
Orlando, FL

Elected to the board in 2000 and sits on the following committees: Finance Committee and Organization and Compensation Committee.

Peter S. Rummell
Chairman and Chief Executive Officer, The St. Joe Company (a real estate operating company)
Jacksonville, FL

Elected to the board in 2003 and sits on the following committees: Organization and Compensation Committee and Operations, Environmental, Health and Safety Issues Committee.

Carlos A. Saladrigas
Chairman, Premier American Bank and Retired Chief Executive Officer, ADP TotalSource
Miami, FL

Elected to the board in 2001 and sits on the following committees: Audit and Corporate Performance Committee and Finance Committee.

J. Tylee Wilson
Retired Chairman and Chief Executive Officer, RJR Nabisco, Inc.
Ponte Vedra Beach, FL

Elected to the board in 1987, presiding director and sits on the following committees: Corporate Governance Committee, Organization and Compensation Committee and Finance Committee.

Jean Giles Wittner
President and Secretary, Wittner & Co., Inc. and subsidiaries (real estate management and insurance brokerage and consulting)
St. Petersburg, FL

Elected to the board in 2000 and sits on the following committees: Audit and Corporate Performance Committee and Operations, Environmental, Health and Safety Issues Committee.

In 2003, the Securities and Exchange Commission and the New York Stock Exchange adopted new rules for corporate governance, including auditor and board independence and internal controls for financial reporting. These changes are designed to ensure accuracy in financial reporting and strong corporate governance.

At Progress Energy, that's how we've always done business.

RESPONSIBILITIES OF KEY BOARD COMMITTEES

Audit and Corporate Performance Committee

The work of this committee includes reviewing the annual and quarterly financial results of the company and the various periodic reports the company files with the SEC. It is responsible for retaining the company's external auditors, overseeing and monitoring the auditors' activities and pre-approving all external audit and non-audit services and fees. This committee also oversees the activities of the internal audit department and the Corporate Ethics Program.

Corporate Governance Committee

The responsibilities of this committee include making recommendations on the structure, charter, practices and policies of the board, including amendments to the Articles of Incorporation and bylaws. This committee ensures that processes are in place for annual CEO performance appraisal, reviews of succession planning and management development. It also recommends the process for the annual assessment of board performance and criteria for board membership. In addition, it proposes nominees to the board.

Finance Committee

This committee reviews and oversees the company's financial policies and planning and the company's pension funds. It monitors the company's financial position, reviews the company's strategic investments and financing options and recommends changes in the company's dividend policy.

Operations, Environmental, Health and Safety Issues Committee

This committee reviews the company's load forecasts and plans for generation, transmission and distribution, fuel production and transportation, customer service, energy trading, term marketing and other company operations. The committee assesses company policies, procedures and practices relative to environmental protection and safety-related issues and advises and makes recommendations to the board regarding these matters.

Organization and Compensation Committee

This committee reviews personnel policies and procedures for consistency with governmental rules and regulations and ensures that the company attracts and retains competent, talented employees. The committee reviews all executive development and management succession plans, evaluates CEO performance and makes senior executive compensation decisions.

EXECUTIVE AND SENIOR OFFICERS

Robert B. McGehee
President and Chief Executive Officer

William D. Johnson
Group President — Energy Delivery

Peter M. Scott III
President and Chief Executive Officer
Progress Energy Service Company, LLC

H. William Habermeyer, Jr.
President and Chief Executive Officer
Progress Energy Florida, Inc.

Tom D. Kilgore
President and Chief Executive Officer
Progress Energy Ventures, Inc.

William S. Orser
Group President — Energy Supply

Geoffrey S. Chatas
Executive Vice President and
Chief Financial Officer

Donald K. Davis
Executive Vice President — Rail and Telecom

Fred N. Day IV
President and Chief Executive Officer
Progress Energy Carolinas, Inc.

Brenda F. Castonguay
Senior Vice President — Administrative Services
Progress Energy Service Company, LLC

C. S. Hinnant
Senior Vice President — Nuclear Generation

Jeffrey J. Lyash
Senior Vice President — Energy Delivery
Progress Energy Florida, Inc.

John R. McArthur
Senior Vice President — Corporate Relations,
General Counsel and Secretary

E. Michael Williams
Senior Vice President — Power Operations

Bonnie V. Hancock
President — Progress Fuels

FINANCIAL REPORT

The following Management's Discussion and Analysis contains forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review the "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

INTRODUCTION

Progress Energy is an integrated energy company, with its primary focus on the end-use and wholesale electricity markets. The Company's reportable business segments and their primary operations include:

- Progress Energy Carolinas Electric (PEC Electric) — primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina;
- Progress Energy Florida (PEF) — primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida;
- Competitive Commercial Operations (CCO) — engaged in nonregulated electric generation operations and marketing activities primarily in the southeastern United States;
- Fuels — primarily engaged in natural gas production in Texas and Louisiana, coal mining and related services, and the production of synthetic fuels and related services, both of which are located in Kentucky, West Virginia and Virginia;
- Rail Services (Rail) — engaged in various rail and railcar-related services in 23 states, Mexico and Canada; and
- Other Businesses (Other) — engaged in other nonregulated business areas, including telecommunications primarily in the eastern United States and energy services operations, which do not meet the requirements for separate segment reporting disclosure.

In 2003, the Company realigned its business segments to reflect the current management structure and assigned new names to the segments to better reflect their operations. For comparative purposes, 2002 and 2001 segment information has been restated to align with the 2003 organizational and reporting structure.

Strategy

The Company's goals, related to its regulated utilities and nonregulated businesses, are to continue focusing on achieving their financial objectives, delivering excellent customer satisfaction and continually striving for operational excellence. The target is to maintain a business mix of approximately 80% regulated and 20% nonregulated business. A summary of the significant financial objectives or issues impacting Progress Energy, its regulated utilities and nonregulated operations are addressed more fully in the following discussion.

PROGRESS ENERGY, INC.

Progress Energy has several key financial objectives, the first of which is to achieve operating cash flows sufficient to meet planned capital expenditures and support its current dividend policy. Any excess cash flow would be used for debt reduction, primarily at the holding company. In addition, the Company seeks to achieve earnings growth through its core regulated utility businesses and through improving returns at its nonregulated businesses. The Company also seeks to maintain ready access to credit markets.

The ability to meet these objectives is largely dependent on the earnings and cash flows of its two regulated utilities. The regulated utilities contributed $787 million of net income and produced over 90% of consolidated cash flow from operations in 2003. In addition, synthetic fuel income of $200 million also contributed significantly to net income. Partially offsetting the net income contribution provided by the regulated utilities and synthetic fuels was a loss of $236 million recorded at Corporate, primarily related to interest expense. While the Company's synthetic fuel operations provide significant earnings, the significant amount of cash flow benefits from synthetic fuels will come in the future when deferred tax credits ultimately are utilized. Credits generated but not utilized are carried forward indefinitely as alternative minimum tax credits and will provide positive cash flow when utilized. At December 31, 2003, deferred credits were $659 million. The Company does not anticipate any significant acquisitions in the near term.

Progress Energy reduced its debt to total capitalization ratio to 58.9% at the end of 2003 as compared to 61.3% at the end of 2002. The Company expects to continue to improve this ratio as it plans to reduce total debt through growth in operating cash flow after dividends, ongoing equity issuances and with proceeds from asset sales. The Company expects capital expenditures to be approximately $1.3 billion in 2004 and in 2005.

Progress Energy continues to maintain investment-grade credit ratings, despite a ratings downgrade in 2003 by both Moody's and Standard & Poor's. Both these ratings agencies upgraded the Company's outlook from "negative"

to "stable" in 2003. The downgrades have not materially affected Progress Energy's access to liquidity or the cost of its short-term borrowings.

REGULATED UTILITIES

The regulated utilities earnings and operating cash flows are heavily influenced by weather, the economy, demand for electricity related to customer growth, actions of regulatory agencies and cost controls.

Both PEC Electric and PEF operate in retail service territories that are forecast to have income and population growth higher than the U.S. average. New housing starts in both these territories are also expected to exceed the U.S. average. In recent years, lower industrial sales, primarily at PEC Electric and mainly related to weakness in the textile sector, have negatively impacted earnings growth. The Company does not expect any significant improvement in industrial sales in the near term. These combined factors, and assuming normal weather, are expected to contribute to approximately 2%-3% annual KWh sales growth at the utilities through at least 2006. The Company does not anticipate any significant additional generation expansion to meet this growth other than the previously planned 500 MW combined-cycle unit at PEF in 2005.

PEC Electric and PEF continue to monitor progress toward a more competitive environment. No retail electric restructuring legislation has been introduced in the jurisdictions in which PEC Electric and PEF operate, and both operate under rate agreements. As part of the Clean Smokestacks bill in North Carolina and an agreement with the Public Service Commission of South Carolina (SCPSC), PEC Electric is operating under a rate freeze in North Carolina through 2007 and a rate cap in South Carolina through 2005. PEF is operating under a rate agreement in Florida through 2005. See Note 7 of the Progress Energy Consolidated Financial Statements for further discussion of the utilities' rates.

The utilities will continue to exercise strong financial discipline as it relates to controlling operation and maintenance costs despite expected increases in benefit-related costs and insurance expense. Operating cash flows are expected to be more than sufficient to fund capital spending in 2004 and in 2005.

NONREGULATED BUSINESSES

The Company's primary nonregulated businesses are CCO, Fuels and Progress Rail.

Cash flows and earnings of the nonregulated businesses are impacted largely by the ability to obtain additional term contracts or sell energy on the spot market at favorable terms, the volume of synthetic fuel produced and tax credits utilized, and volumes and prices of both coal and natural gas sales.

Progress Energy expects an excess of supply in the wholesale electric energy market for the next several years. During 2003, CCO completed the build-out of its nonregulated generation assets bringing CCO's total capacity to 3,100 MW. The Company has no current plans to expand its portfolio of nonregulated generating plants. The Company has contracts for planned production capacity of 85% in 2004 and 50% for both 2005 and 2006. CCO will continue to seek to secure term contracts with load-serving entities to utilize its excess capacity.

Fuels will continue to develop its natural gas production asset base both as a long-term economic hedge for the Company's nonregulated generation fuel needs and to obtain a meaningful presence in natural gas markets that will allow it to provide attractive returns for the Company's shareholders. In 2004, Fuels anticipates that, with budgeted capital expenditures, it will have a 25% increase in gas production.

The Company's majority-owned synthetic fuel entities participate in the Internal Revenue Service (IRS) Prefiling Agreement (PFA) program. The PFA program is a program that allows taxpayers to voluntarily accelerate the IRS exam process in order to seek resolution of specific issues. The Company has resolved certain issues with the IRS and is continuing to work with the IRS to resolve any remaining issues. The Company cannot predict when the exam process will be completed or the final resolution of any outstanding matters. These facilities have private letter rulings (PLRs) from the IRS with respect to their synthetic fuel operations. The Company has no current plans to alter its synthetic fuel production schedule as a result of these matters. The Company plans to produce approximately 11 million to 12 million tons of synthetic fuel in 2004. Through December 31, 2003, the Company had generated $1,243 million of synthetic fuel tax credits to date (including Florida Progress Corporation [FPC] prior to the acquisition by the Company). See additional discussion at Synthetic Fuel Tax Credits in the "Other Matters" section below and at Note 14 to the Progress Energy Consolidated Financial Statements.

Progress Energy continues to look for opportunities to divest of its Progress Rail subsidiary at an opportune time as it is not considered part of its core business strategy in the future. The Company expects to accomplish the divestiture within the next three years.

RESULTS OF OPERATIONS

For 2003 as compared to 2002 and 2002 as compared to 2001

In this section, earnings and the factors affecting earnings are discussed. The discussion begins with a summarized overview of the Company's consolidated earnings, which is followed by a more detailed discussion and analysis by business segment.

Progress Energy

In 2003, Progress Energy's net income was $782 million, a 48% increase from $528 million in 2002. Income from continuing operations before cumulative effect of changes in accounting principles and discontinued operations was $811 million in 2003, a 47% increase from $552 million in 2002. Net income for 2003 increased compared to 2002, primarily due to the inclusion in 2002 of an impairment of $265 million after-tax related to assets in the telecommunications and rail businesses. The Company recorded impairments of $23 million after-tax in 2003 on an investment portfolio and on long-lived assets. The increase in net income in 2003 of $12 million, excluding the impairments, is primarily due to:

- An increase in retail customer growth at the utilities.
- Growth in natural gas production and sales.
- Higher synthetic fuel sales.
- Absence of severe storm costs incurred in 2002.
- Lower loss recorded in 2003 related to the sale of NCNG, with the majority of the loss on the sale being recorded in 2002.
- Lower interest charges in 2003.

Partially offsetting these items were the:

- Net impact of the 2002 Florida Rate settlement.
- Impact of the change in the fair value of the CVOs.
- Milder weather in 2003 as compared to 2002.
- Increased benefit-related costs.
- Higher depreciation expense at both utilities and the Fuels and CCO segments.
- The impact of changes in accounting principles in 2003.

Each of these items is discussed further in the results of operations for the segments below.

Basic earnings per share from net income increased from $2.43 per share in 2002 to $3.30 per share in 2003 in part due to the factors outlined above. Dilution related to a November 2002 equity issuance of 14.7 million shares and issuances under the Company's Investor Plus and employee benefit programs in 2002 and 2003 also reduced basic earnings per share by $0.33 in 2003.

Net income in 2002 decreased 2.6% from $542 million in 2001. The decrease in net income in 2002 is primarily due to impairments and other charges related to the telecommunications and rail business operations, the discontinued operations of NCNG, the rate case settlement of PEF, PEC severe storm costs and increased benefit costs. Partially offsetting these items were continued customer growth and usage at the utilities, lower depreciation at PEF, 2001 impairments in the telecommunications and SRS business units, the impact of the change in market value of CVOs and the elimination of goodwill amortization in 2002.

The Company's segments contributed the following profit or loss from continuing operations for 2003, 2002 and 2001:

(in millions)	2003	Change	2002	Change	2001
PEC Electric	$515	$2	$513	$45	$468
PEF	295	(28)	323	14	309
Fuels	235	59	176	(23)	199
CCO	20	(7)	27	23	4
Rail Services	(1)	41	(42)	(30)	(12)
Other	(17)	226	(243)	(81)	(162)
Total Segment Profit (Loss)	$1,047	$293	$754	$(52)	$806
Corporate	(236)	(34)	(202)	63	(265)
Total Income from Continuing Operations	$811	$259	$552	$11	$541
Discontinued Operations, Net of Tax	(8)	16	(24)	(25)	1
Cumulative Effect of Changes in Accounting Principles	(21)	(21)	—	—	—
Net Income	$782	$254	$528	$(14)	$542

Progress Energy Carolinas Electric

PEC Electric contributed segment profits of $515 million, $513 million and $468 million in 2003, 2002 and 2001, respectively. The slight increase in profits in 2003, when compared to 2002, was primarily due to customer growth, strong wholesale sales during the first quarter of 2003, lower Service Company allocations and lower interest costs, which were offset by unfavorable weather in 2003, higher depreciation expense and increased benefit-related costs. The increase in profits in 2002, when compared to 2001, was attributable to customer growth, favorable weather in 2002, lower interest charges and the allocation of tax benefits from the holding company partially offset by severe storm costs in December 2002.

REVENUES

PEC Electric's electric revenues for the years ended December 31, 2003, 2002 and 2001, and the percentage change by year and by customer class are as follows:

(in millions) Customer Class	2003	% Change	2002	% Change	2001
Residential	$1,259	1.5%	$1,241	7.7%	$1,152
Commercial	850	2.2	832	6.0	785
Industrial	636	(1.4)	645	(1.4)	654
Governmental	79	1.3	78	4.0	75
Total Retail Revenues	2,824	1.0	2,796	4.9	2,666
Wholesale	687	5.5	651	2.7	634
Unbilled	(6)	—	15	—	(32)
Miscellaneous	84	9.1	77	1.3	76
Total Electric Revenues	$3,589	1.4%	$3,539	5.8%	$3,344

PEC Electric's electric energy sales for 2003, 2002 and 2001 and the percentage change by year and by customer class are as follows:

(in thousands of MWh) Customer Class	2003	% Change	2002	% Change	2001
Residential	15,283	0.3%	15,239	6.0%	14,372
Commercial	12,557	0.7	12,468	4.1	11,972
Industrial	12,749	(2.6)	13,089	(1.8)	13,332
Governmental	1,408	(2.0)	1,437	1.0	1,423
Total Retail Energy Sales	41,997	(0.6)	42,233	2.8	41,099
Wholesale	15,518	3.3	15,024	15.6	12,996
Unbilled	(44)	—	270	—	(534)
Total MWh Sales	57,471	(0.1)%	57,527	7.4%	53,561

PEC Electric's revenues, excluding recoverable fuel revenues of $901 million and $851 million in 2003 and 2002, respectively, were unchanged from 2002 to 2003. Milder weather in 2003, when compared to 2002 accounted for a $61 million retail revenue reduction. While heating degree days were 4.8% above prior year, cooling degree days were 25.2% below prior year. However, the more severe weather in the northeast region of the United States during the first quarter of 2003 drove a $19 million increase in wholesale revenues. Additionally, retail customer growth in 2003 generated an additional $42 million of revenues in 2003. PEC Electric's retail customer base increased as approximately 23,000 new customers were added in 2003.

PEC's electric revenues, excluding recoverable fuel revenues of $851 million and $734 million in 2002 and 2001, respectively, increased $78 million. During 2002, residential and commercial sales reflected continued growth in the number of customers served by PEC Electric, with approximately 26,000 new customers in 2002. Sales of energy and revenue increased in 2002 compared to 2001 for all customer classes except industrial. Increases in retail sales and wholesale sales were also driven by favorable weather during 2002 when compared to 2001. Wholesale sales growth was partially offset by price declines in the wholesale market.

Downturns in the economy during 2001, 2002 and 2003 impacted energy usage within the industrial customer class. Total industrial revenues, excluding fuel revenues, declined during 2003 when compared to 2002 and during 2002 when compared to 2001 by $13 million and $24 million, respectively, as the number of industrial customers decreased due to a slowdown in the textile industry, as well as a decrease in usage in the chemical industry.

EXPENSES

Fuel and Purchased Power

Fuel expense increased $73 million in 2003, when compared to the $752 million total in 2002, primarily due to higher prices incurred for coal, oil and natural gas used during generation. Costs for fuel per Btu increased for all three commodities during the year. Fuel expense increased $114 million in 2002, when compared to the $638 million in 2001, primarily due to an 8.2% increase in generation with a higher percentage of generation being produced by combustion turbines, which have higher fuel costs.

Purchased power expense decreased $51 million in 2003, when compared to the $347 million in 2002, mainly due to a decrease in the volume purchased as milder weather reduced system requirements and due to the renegotiation at more favorable terms of two contracts that expired during the year. For 2002, purchased power decreased $7 million, when compared to the $354 million in 2001, mainly due to decreases in prices and volumes purchased.

Fuel expenses are recovered primarily through cost recovery clauses and, as such, changes in expense have no material impact on operating results.

Operations and Maintenance (O&M)

O&M expense decreased $20 million in 2003 when compared to $802 million in 2002. O&M expense in 2002 included severe storm costs of $27 million. Those costs along with lower 2003 Service Company allocations of $16 million, due to the change in allocation methodology as required by the SEC in early 2003, are the primary reasons for decreased O&M expenses. This decrease was partially offset by higher benefit-related costs of $21 million. PEC Electric incurred O&M costs of $25 million related to three severe storms in 2003. The North Carolina Utilities Commission (NCUC) allowed deferral of $24 million of

these storm costs. These costs are being amortized over a five-year period, beginning in the months the expenses were incurred. PEC Electric amortized $3 million of these costs in 2003, which is included in depreciation and amortization expense on the Consolidated Income Statement.

O&M expense increased $91 million in 2002 when compared to $711 million in 2001, primarily due to the 2002 storm costs of $27 million, which were not deferred. O&M expense in 2002, when compared to 2001, was also negatively impacted by a lower pension credit of $6 million, the establishment of an inventory reserve of $11 million for materials that have no future benefit, increased salaries and benefits and other increases in maintenance and outage support.

Depreciation and Amortization

Depreciation and amortization increased $38 million in 2003, when compared to $524 million in 2002. Depreciation and amortization increased $74 million related to the 2003 impact of the Clean Air legislation in North Carolina, and decreased $53 million related to the 2002 impact of the accelerated nuclear amortization program. Both programs are approved by the state regulatory agencies and are discussed further at Notes 7 and 21E to the Progress Energy Consolidated Financial Statements. In addition, depreciation increased $19 million due to additional assets placed into service.

Depreciation and amortization increased $2 million in 2002 when compared to $522 million in 2001. PEC Electric recorded $53 million of accelerated amortization expense in 2002 and $75 million in 2001 related to the nuclear amortization program. The year-over-year favorability was offset by additional depreciation recognized in 2002, as compared to 2001, on new assets that were placed in service during 2002.

PEC filed a new depreciation study in 2004 that provides support for reducing depreciation expense on an annual basis by approximately $45 million. The reduction is primarily attributable to assumption changes for nuclear generation, offset by increases for distribution assets. The new rates are primarily effective January 1, 2004.

Interest Expense

Net interest expense was $194 million, $212 million and $241 million in 2003, 2002 and 2001, respectively. Declines in interest expense resulted from reduced short-term debt and refinancing certain long-term debt with lower interest rate debt.

Income Tax Expense

In 2003 and 2002, $24 million and $35 million, respectively, of the tax benefit that was previously held at the Company's holding company was allocated to PEC Electric. As required by an SEC order issued in 2002, holding company tax benefits are allocated to profitable subsidiaries. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

Progress Energy Florida

PEF contributed segment profits of $295 million, $323 million and $309 million in 2003, 2002 and 2001, respectively. The decrease in profits in 2003, when compared to 2002, was primarily due to the impact of the 2002 rate case stipulation, higher benefit-related costs primarily related to higher pension expense, higher depreciation and the unfavorable impact of weather. These amounts were partially offset by continued customer growth and lower interest charges. The increase in profits in 2002, when compared to 2001, was attributed to the impact of milder weather in 2001 as compared to 2002, continued customer growth and the allocation of tax benefits from the holding company. These items were partially offset by the impact of the 2002 rate case stipulation, increased benefits costs and lower pension credit and higher system reliability and enhancement spending.

PEF's profits in 2003 and 2002 were affected by the outcome of the rate case stipulation, which included a one-time retroactive revenue refund in 2002, a decrease in retail rates of 9.25% (effective May 1, 2002), provisions for revenue sharing with the retail customer base, lower depreciation and amortization and increased service revenue rates. See Note 7D to the Progress Energy Consolidated Financial Statements for further discussion of the rate case settlement.

REVENUES

PEF's electric revenues for the years ended December 31, 2003, 2002 and 2001, and the percentage change by year and by customer class, as well as the impact of the rate case settlement on revenue, are as follows:

(in millions) Customer Class	2003	% Change	2002	% Change	2001
Residential	$1,691	2.8%	$1,645	0.1%	$1,643
Commercial	740	1.2	731	(3.1)	754
Industrial	219	3.8	211	(5.4)	223
Governmental	181	4.6	173	(1.7)	176
Revenue Sharing Refund	(35)	—	(5)	—	—
Retroactive Retail Rate Refund	—	—	(35)	—	—
Total Retail Revenues	2,796	2.8	2,720	(2.7)	2,796
Wholesale	227	(1.3)	230	(20.1)	288
Unbilled	(2)	—	(3)	—	(22)
Miscellaneous	131	13.9	115	(23.8)	151
Total Electric Revenues	$3,152	2.9%	$3,062	(4.7)%	$3,213

PEF's electric energy sales for the years ended December 31, 2003, 2002 and 2001, and the percentage change by year and by customer class are as follows:

(in thousands of MWh) Customer Class	2003	% Change	2002	% Change	2001
Residential	19,429	3.6%	18,754	6.5%	17,604
Commercial	11,553	1.2	11,420	3.2	11,061
Industrial	4,000	4.3	3,835	(1.0)	3,872
Governmental	2,974	4.4	2,850	4.5	2,726
Total Retail Energy Sales	37,956	3.0	36,859	4.5	35,263
Wholesale	4,323	3.4	4,180	(11.4)	4,719
Unbilled	233	—	5	—	(511)
Total MWh Sales	42,512	3.6%	41,044	4.0%	39,471

PEF's revenues, excluding fuel revenues of $1,487 million and $1,402 million in 2003 and 2002, respectively, increased $5 million from 2002 to 2003. Revenues were favorably impacted by $49 million in 2003, primarily as a result of customer growth (approximately 36,000 additional customers). In addition, other operating revenues were favorable by $16 million due primarily to higher wheeling and transmission revenues and higher service charge revenues (resulting from increased rates allowed under the 2002 rate settlement). These increases were partially offset by the negative impact of the rate settlement, which decreases revenues, lower wholesale sales and the impact of unfavorable weather. The provision for revenue sharing increased $12 million in 2003 compared to the $5 million provision recorded in 2002. Revenues in 2003 were also impacted by the final resolution of the 2002 revenue sharing provisions as the Florida Public Service Commission (FPSC) issued an order in July of 2003 that required PEF to refund an additional $18 million to customers related to 2002. The 9.25% rate reduction from the settlement accounted for an additional $46 million decline in revenues. The 2003 impact of the rate settlement was partially offset by the absence of the prior year interim rate refund of $35 million. Lower wholesale revenues (excluding fuel revenues) of $17 million and the $8 million impact of milder weather also reduced base revenues during 2003.

PEF's revenues, excluding fuel revenues of $1,402 million and $1,453 million in 2002 and 2001, respectively, decreased $100 million from 2001 to 2002. The revenue declines were driven by the $119 million impact of the rate case, comprised of a $35 million one-time retroactive refund, a $79 million decrease due to the rate reduction, and an estimated revenue sharing refund of $5 million. Additionally, wholesale revenues (excluding fuel revenues) declined $12 million, driven primarily by a contract that was not renewed. Year-over-year comparisons were also unfavorably impacted by the recognition of $63 million of revenue deferred from 2000 to 2001. Partially offsetting the unfavorable revenue impacts was customer growth (approximately 33,000 additional customers), the impact of weather conditions, primarily a warmer than normal summer in 2002, and an increase in other operating revenue resulting primarily from higher service charge revenues (a result of increased rates allowed under the 2002 rate case settlement), along with higher transmission and wheeling revenues.

EXPENSES

Fuel and Purchased Power

Fuel used in generation and purchased power increased $87 million in 2003, when compared to $1,349 million in 2002. The increase is due to higher costs to generate electricity and higher purchased power costs as a result of an increase in volume due to system requirements and higher natural gas prices.

Fuel used in generation and purchased power totaled $1,349 million for the year ended December 31, 2002, a decrease of $71 million from 2001. The decrease is primarily due to a lower recovery of fuel expense that resulted from a mid-course correction of PEF's fuel cost recovery clause, as part of the rate settlement, and lower purchased power costs, partially offset by an increase in coal prices and volume from high system requirements.

Fuel and purchased power expenses are recovered primarily through cost recovery clauses and, as such, changes in expense have no material impact on operating results.

Operations and Maintenance (O&M)

O&M expense increased $49 million, when compared to $591 million in 2002. The increase is largely related to increases in certain benefit-related expenses of $36 million, which consisted primarily of a higher pension expense of $27 million and higher operational costs related to the CR3 nuclear outage and plant maintenance.

O&M expense increased $96 million in 2002 when compared to $495 million in 2001, due primarily to a reduced pension credit of $31 million, increased costs related to the Commitment to Excellence program of $11 million, and an increase in other salary and benefit costs of $22 million related partially to increased medical costs. The Commitment to Excellence program was initiated in 2002 to improve service and reliability.

Depreciation and Amortization

Depreciation and amortization increased $12 million in 2003 when compared to $295 million in 2002.

Depreciation increased primarily as a result of additional assets being placed into service that were partially offset by lower amortization of the Tiger Bay regulatory asset of $2 million, which was fully amortized in September 2003.

Depreciation and amortization decreased $158 million in 2002 when compared to $453 million in 2001. In addition to the depreciation and amortization reduction of approximately $79 million related to the rate case, depreciation declined an additional $97 million related to accelerated amortization on the Tiger Bay regulatory asset, which was created as a result of the early termination of certain long-term cogeneration contracts. See Note 7D to the Progress Energy Consolidated Financial Statements for further details on the rate case. PEF amortized the regulatory asset according to a plan approved by the FPSC in 1997.

Interest Expense

Interest charges decreased $15 million in 2003 compared to $106 million in 2002, primarily due to the reversal of a regulatory liability for accrued interest related to previously resolved tax matters.

Income Tax Expense

In 2003 and 2002, $13 million and $20 million, respectively, of the tax benefit that was previously held at the Company's holding company was allocated to PEF. As required by an SEC order issued in 2002, holding company tax benefits are allocated to profitable subsidiaries. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

Diversified Businesses

The Company's diversified businesses consist of the Fuels segment, the CCO segment, the Rail Services segment and the Other segment, which consists primarily of the energy services operations and telecommunications operations.

Fuels

Fuels' segment profits increased $59 million in 2003 as compared to $176 million in 2002 primarily due to an increase in synthetic fuel earnings, higher natural gas earnings from increased natural gas prices, the addition of North Texas Gas operations in March 2003 and the addition of Westchester in April 2002. These results were partially offset by an asset impairment during the fourth quarter of $11 million after-tax at the Kentucky May Coal Company. Fuels' 2002 profits as compared to 2001 decreased $23 million primarily as a result of lower synthetic fuel production, which was partially offset by increased natural gas revenues as a result of the Westchester acquisition.

Fuels contributed segment profits of $235 million, $176 million and $199 million in 2003, 2002 and 2001, respectively. The following summarizes Fuels' segment profits for the years ended December 31, 2003, 2002 and 2001:

(in millions)	2003	2002	2001
Synthetic fuel operations	$200	$156	$185
Natural gas operations	34	10	5
Coal fuel and other operations	1	10	9
Segment profits	$235	$176	$199

SYNTHETIC FUEL OPERATIONS

Synthetic fuel operations generated profits of $200 million, $156 million and $185 million, respectively, for the years ended December 31, 2003, 2002 and 2001. The production and sale of the synthetic fuel generate operating losses, but qualify for tax credits under Section 29, which more than offset the effects of such losses. See "Synthetic Fuels Tax Credits" under "Other Matters" below for additional discussion of these tax credits. The operations resulted in the following losses (prior to tax credits) and tax credits for 2003, 2002 and 2001:

(in millions)	2003	2002	2001
Tons sold	12.4	11.2	13.3
After-tax losses (excluding tax credits)	$(145)	$(135)	$(164)
Tax credits	345	291	349
Net Profit	$200	$156	$185

Synthetic fuels' net profits for 2003 increased as compared to 2002 due to higher sales, improved margins and a higher tax credit per ton. The 2003 tax credits also include a $12.7 million favorable true-up from 2002. Additionally, synthetic fuels' results in 2003 include 13 months of operations for some facilities. Prior to the fourth quarter of 2003, results of these synthetic fuels' operations had been recognized one month in arrears. The net impact of this action increased net income by $2 million for the year. Synthetic fuels' net profits decreased in 2002 compared to 2001 due to lower sales. Synthetic fuels' net profits decreased $29 million in 2002 when compared to 2001. The decrease in profits was primarily due to a decline in tons produced as severe storm costs, incurred at one of the utilities, reduced the Company's ability to use the tax credits generated from production.

NATURAL GAS OPERATIONS

Natural gas operations generated profits of $34 million, $10 million and $5 million for the years ended December 31, 2003, 2002 and 2001, respectively. The increase in production and price resulting from the acquisitions of

Westchester in 2002 and North Texas Gas in the first quarter of 2003 drove increased revenue and earnings in 2003 as compared to 2002. In October of 2003, the Company completed the sale of certain gas-producing properties owned by Mesa Hydrocarbons, LLC. See Notes 4 and 3C to the Progress Energy Consolidated Financial Statements for discussions of the Westchester and the North Texas Gas acquisitions and the Mesa disposition. The increase in profits of $5 million from 2001 to 2002 is due to an increase in gas production of 49% as a result of the Westchester acquisition in April of 2002. The following summarizes the production and revenues of the natural gas operations for 2003, 2002 and 2001 by facility:

	2003	2002	2001
Production in Bcf equivalent			
Mesa	4.8	6.0	8.3
Westchester	13.5	5.8	—
North Texas Gas	7.1	—	—
Total Production	25.4	11.8	8.3
Revenues in millions			
Mesa	$13	$15	$18
Westchester	65	24	—
North Texas Gas	38	—	—
Total Revenues	$116	$39	$18
Gross Margin			
In millions of $	$91	$29	$15
As a % of revenues	78%	74%	83%

COAL FUEL AND OTHER OPERATIONS

Coal fuel and other operations generated profits of $1 million, $10 million and $9 million, respectively, for the years ended December 31, 2003, 2002 and 2001. Coal fuel and other operations segment profits decreased $9 million from 2002 to 2003. The decrease is due primarily to the recording of an impairment of certain assets at the Kentucky May Coal Mine totaling $11 million after-tax. See discussion of impairment recorded in Note 9 to the Progress Energy Consolidated Financial Statements.

Competitive Commercial Operations

CCO generates and sells electricity to the wholesale market from nonregulated plants. These operations also include marketing activities.

CCO's operations generated segment profits of $20 million, $27 million and $4 million in 2003, 2002 and 2001, respectively. CCO's operations were most significantly impacted by placing additional generating capability into service in 2002 and 2003. The following summarizes the annual revenues, gross margin and segment profits from the CCO plants:

(in millions)	2003	2002	2001
Total revenues	$170	$92	$16
Gross margin			
In millions of $	$141	$83	$14
As a % of revenues	83%	90%	87%
Segment profits	$20	$27	$4

The increase in revenue for 2003 when compared to 2002 is primarily due to increased contracted capacity on newly constructed plants, energy revenue from a new, full-requirements power supply contract and a tolling agreement termination payment received during the first quarter. Generating capacity increased from 1,554 megawatts at December 31, 2002, to 3,100 megawatts at December 31, 2003, with the Effingham, Rowan Phase 2 and Washington plants being placed in service in 2003. In the second quarter of 2003, Progress Energy Ventures, Inc. (PVI) acquired from Williams Energy Marketing and Trading a full-requirements power supply agreement with Jackson in Georgia for $188 million, which resulted in additional revenues of $21 million when compared to the same periods in 2002. The revenue increases related to higher volumes were partially offset by higher depreciation costs of $22 million, increased interest charges of $16 million and other fixed charges.

The increase in revenues from 2001 to 2002 is due to the increase in capacity during the year. In 2001 operations included one nonregulated plant with a 315-megawatt capacity and, at the end of 2002, plants with 1,554 megawatts of capacity were operational. The increase in capacity was due to the transfer of one plant from PEC Electric, the purchase of one operational plant from LG&E Energy Corp. (See Note 4D to the Progress Energy Consolidated Financial Statements) and one additional plant being placed in service. The increase in capacity drove the increase in net income. The earnings potential was offset by general softness in the energy market in 2002.

The Company has contracts representing 85%, 50%, and 50% of planned production capacity for 2004 through 2006, respectively. The Company is actively pursuing opportunities with current customers and other potential new customers to utilize its excess capacity.

Rail Services

Rail Services' (Rail) operations represent the activities of Progress Rail and include railcar and locomotive repair, trackwork, rail parts reconditioning and sales, scrap metal recycling, railcar leasing and other rail-related services. Rail's results for the year ended December 31, 2001, include Rail Services' cumulative revenues and net loss from the date of acquisition, November 30, 2000,

because Rail Services had been held for sale from the date of acquisition through the second quarter of 2001.

Rail contributed losses of $1 million, $42 million and $12 million for the years ended December 31, 2003, 2002 and 2001, respectively. The net loss in 2002 includes a $40 million after-tax estimated impairment of assets held for sale related to Railcar Ltd., a leasing subsidiary of Progress Rail. In March 2003, the Company signed a letter of intent to sell the majority of Railcar Ltd. assets to The Andersons, Inc. The asset purchase agreement was signed in November 2003 and the transaction closed on February 12, 2004. As such, assets of Railcar Ltd. have been reported as assets held for sale. See Note 3B to the Progress Energy Consolidated Financial Statements for discussion of this divestiture. Excluding the impairment recorded in 2002, profits for Rail were flat year over year 2003 compared to 2002. Earnings for Rail increased in 2002 compared to 2001, excluding the $40 million impairment booked in 2002 as discussed above. Rail Services' 2002 results were favorably impacted by aggressive cost cutting, new business opportunities and restructuring initiatives. Rail Services' results for both years were affected by a downturn in the overall economy and decreases in rail service procurement by major railroads. A downturn in the domestic scrap market also impacted Rail Services results for 2002.

An SEC order approving the merger of FPC required the Company to divest of Progress Rail by November 30, 2003. However, the SEC has granted an extension until 2006.

Other

Progress Energy's Other segment includes the operations of SRS, the telecommunications operations of PTC and Caronet and the operation of nonutility subsidiaries of PEC. SRS is engaged in providing energy services to industrial, commercial and institutional customers to help manage energy costs and currently focuses its activities in the southeastern United States. Telecommunication operations provide broadband capacity services, dark fiber and wireless services in Florida and the eastern United States. In December 2003, PTC and Caronet, both wholly-owned subsidiaries of Progress Energy, and EPIK, a wholly-owned subsidiary of Odyssey, contributed substantially all of their assets and transferred certain liabilities to PTC LLC, a subsidiary of PTC. Subsequently, the stock of Caronet was sold to an affiliate of Odyssey for $2 million in cash, and Caronet became an indirect wholly-owned subsidiary of Odyssey. Following consummation of all the transactions described above, PTC holds a 55% ownership interest in, and is the parent of, PTC LLC. Odyssey holds a combined 45% ownership interest in PTC LLC through EPIK and Caronet. The accounts of PTC LLC are included in the Company's Consolidated Financial Statements since the transaction date.

The Other segment contributed segment losses of $17 million, $243 million and $162 million, respectively, for the years ended December 31, 2003, 2002 and 2001. Included in the 2003 segment losses is an investment impairment of $6 million after-tax on the Affordable Housing portfolio held by the nonutility subsidiaries of PEC. The 2002 segment losses include an asset impairment and other charges in the telecommunications business of $225 million after-tax. Segment losses in 2001 include an asset and investment impairment recorded at SRS ($46 million after-tax) and investment impairments in Interpath Communications, Inc. (Interpath) of $102 million after-tax. See discussion of impairments at Note 9 of the Progress Energy Consolidated Financial Statements.

Corporate Services

Corporate Services (Corporate) includes the operations of the holding company, Progress Energy Service Company and other consolidating and nonoperating entities, as summarized below:

Income (Expense) (in millions)	2003	Change	2002	Change	2001
Other interest expense	$(285)	$(10)	$(275)	$(14)	$(261)
Contingent value obligations	(9)	(37)	28	30	(2)
Tax reallocation	(38)	18	(56)	(56)	—
Other income taxes	124	11	113	68	45
Other income (expense)	(28)	(16)	(12)	35	(47)
Segment loss	$(236)	$(34)	$(202)	$63	$(265)

Net pre-tax interest charges in Corporate were $285 million, $275 million and $261 million for the years ended December 31, 2003, 2002 and 2001, respectively. Interest expense increased $10 million in 2003 compared to 2002 due to a decrease of $9 million in the amount of interest capitalized related to construction at nonregulated generating plants, as construction was completed and plants were placed in service. The increase in 2002, when compared to 2001, was primarily related to increased debt associated with the purchase of nonregulated generating facilities. This was partially offset by lower interest rates and $19 million of interest capitalization in 2002 related to the building of the nonregulated generating plants.

Progress Energy issued 98.6 million CVOs in connection with the FPC acquisition. Each CVO represents the right to receive contingent payments based on the performance of four synthetic fuel facilities owned by Progress Energy. The payments, if any, are based on the net after-tax cash

flows the facilities generate. At December 31, 2003, 2002, and 2001, the CVOs had a fair market value of approximately $23 million, $14 million, and $42 million, respectively. Progress Energy recorded unrealized losses of $9 million and $2 million for the years ended December 31, 2003 and 2001, and an unrealized gain of $28 million for the year ended December 31, 2002, to record the changes in fair value of CVOs, which had average unit prices of $0.23, $0.14, and $0.43 at December 31, 2003, 2002 and 2001, respectively.

As required by an SEC order issued in 2002, holding company tax benefits are allocated to profitable subsidiaries. Tax benefits reallocated from the holding company to the profitable subsidiaries increased Corporate's income tax expense by $38 million and $56 million in 2003 and 2002. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

As part of the acquisition of FPC, goodwill of approximately $3.6 billion was recorded, and amortization of $90 million was included in other income (expense) at the Corporate segment in 2001. In accordance with Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," (SFAS No. 142) effective January 1, 2002, the Company no longer amortizes goodwill. See Note 8 to the Progress Energy Consolidated Financial Statements for more details on goodwill.

Discontinued Operations

In 2002, the Company approved the sale of NCNG to Piedmont Natural Gas Company, Inc. As a result, the operating results of NCNG were reclassified to discontinued operations for all reportable periods. Progress Energy sold NCNG and ENCNG for net proceeds of approximately $450 million. Progress Energy incurred a loss from discontinued operations of $8 million for the year ended December 31, 2003, compared with a loss of $24 million for 2002. The loss for 2003 reflects the finalization of the sale of NCNG. See Note 3A to the Progress Energy Consolidated Financial Statements for more information on this divestiture.

Cumulative Effect of Accounting Changes

Progress Energy recorded adjustments for the cumulative effects of changes in accounting principles due to the adoption of several new accounting pronouncements. These adjustments totaled to a $21 million loss after-tax, which was due primarily to new Financial Accounting Standards Board (FASB) guidance related to the accounting for certain contracts. This guidance discusses whether the pricing in a contract that contains broad market indices qualifies for certain exceptions that would not require the contract to be recorded at its fair value. PEC Electric had a purchase power contract with Broad River LLC that did not meet the criteria for an exception, and a negative fair-value adjustment was recorded in the fourth quarter of 2003 for $23 million after-tax. See Note 17A to the Progress Energy Consolidated Financial Statements.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Company prepared its consolidated financial statements in accordance with accounting principles generally accepted in the United States. In doing so, certain estimates were made that were critical in nature to the results of operations. The following discusses those significant estimates that may have a material impact on the financial results of the Company and are subject to the greatest amount of subjectivity. Senior management has discussed the development and selection of these critical accounting policies with the Audit Committee of the Company's Board of Directors.

Utility Regulation

The Company's regulated utilities segments are subject to regulation that sets the prices (rates) the Company is permitted to charge customers based on the costs that regulatory agencies determine the Company is permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by a nonregulated company. This ratemaking process results in deferral of expense recognition and the recording of regulatory assets based on anticipated future cash inflows. As a result of the changing regulatory framework in each state in which the Company operates, a significant amount of regulatory assets has been recorded. The Company continually reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. Additionally, the state regulatory agencies often provide flexibility in the manner and timing of the depreciation of property, nuclear decommissioning costs and amortization of the regulatory assets. Note 7 to the Progress Energy Consolidated Financial Statements provides additional information related to the impact of utility regulation on the Company.

Asset Impairments

The Company evaluates the carrying value of long-lived assets for impairment whenever indicators exist. Examples of these indicators include current period losses combined with a history of losses, or a projection of

continuing losses, or a significant decrease in the market price of a long-lived asset group. If an indicator exists, the asset group held and used is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or if the asset group is to be disposed of, an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. A high degree of judgment is required in developing estimates related to these evaluations and various factors are considered, including projected revenues and cost and market conditions.

Due to the reduction in coal production at the Kentucky May Coal Mine, the Company evaluated its long-lived assets in 2003 and recorded an impairment of $17 million before tax ($11 million after-tax). See Note 9A to the Progress Energy Consolidated Financial Statements for further information on this impairment and other charges.

During 2002, the Company recorded pre-tax long-lived asset impairments of $305 million related to its telecommunications business. See Note 9A to the Progress Energy Consolidated Financial Statements for further information on this impairment and other charges. The fair value of these assets was determined using an external valuation study heavily weighted on a discounted cash flow methodology and using market approaches as supporting information.

The Company also continually reviews its investments to determine whether a decline in fair value below the cost basis is other than temporary. In 2003, the Company's affordable housing investment (AHI) portfolio was reviewed and deemed to be impaired based on various factors, including continued operating losses of the AHI portfolio and management performance issues arising at certain properties within the AHI portfolio. As a result, the Company recorded impairments of $18 million on a pre-tax basis during the fourth quarter of 2003. The Company also recorded an impairment of $3 million for a cost investment. During 2002 and 2001, the Company recorded pre-tax impairments to its cost method investment in Interpath of $25 million and $157 million, respectively. The fair value of this investment was determined using an external valuation study heavily weighted on a discounted cash flow methodology and using market approaches as supporting information. These cash flows included numerous assumptions including the pace at which the telecommunications market would rebound. In the fourth quarter of 2002, the Company sold its remaining interest in Interpath for a nominal amount.

Goodwill

Effective January 1, 2002, the Company adopted SFAS No. 142, which requires that goodwill be tested for impairment at least annually and more frequently when indicators of impairment exist. See Note 8 to the Progress Energy Consolidated Financial Statements for further detail on goodwill. SFAS No. 142 requires a two-step goodwill impairment test. The Company performs the annual goodwill impairment test each year. The first step, used to identify potential impairment, compares the fair value of the reporting unit with its carrying amount, including goodwill. The second step, used to measure the amount of the impairment loss if step one indicates a potential impairment, compares the implied fair value of the reporting unit goodwill with the carrying amount of the goodwill.

The Company completed the initial transitional goodwill impairment test, which indicated that the Company's goodwill was not impaired as of January 1, 2002. The carrying amounts of goodwill at December 31, 2003 and 2002, for reportable segments PEC Electric, PEF and CCO, are $1,922 million, $1,733 million and $64 million, respectively.

During 2003, the Other segment acquired $7 million in goodwill as part of the PTC business combination with EPIK. The Company performed the annual goodwill impairment test for the CCO segment in the first quarter of 2003, and the annual goodwill impairment test for the PEC Electric and PEF segments in the second quarter of 2003, which indicated no impairment. If the fair values for the utility segments were lower by 10%, there still would be no impact on the reported value of their goodwill.

During 2002, the Company completed the acquisition of two electric generating projects, Walton County Power, LLC and Washington County Power, LLC. The acquisitions resulted in goodwill of $64 million.

Synthetic Fuels Tax Credits

Progress Energy, through the Fuels business unit, produces coal-based synthetic fuel. The production and sale of the synthetic fuel qualifies for tax credits under Section 29 if certain requirements are satisfied, including a requirement that the synthetic fuel differs significantly in chemical composition from the feedstock used to produce such synthetic fuel and that the fuel was produced from a facility that was placed in service before July 1, 1998. Any synthetic fuel tax credit amounts not utilized are carried forward indefinitely and are included in deferred taxes on the accompanying Consolidated Balance Sheets. See

Note 14 to the Progress Energy Consolidated Financial Statements for further information on the synthetic fuel tax credits. All of Progress Energy's synthetic fuel facilities have received PLRs from the IRS with respect to their operations. These tax credits are subject to review by the IRS, and if Progress Energy fails to prevail through the administrative or legal process, there could be a significant tax liability owed for previously taken Section 29 credits, with a significant impact on earnings and cash flows.

Pension Costs

As discussed in Note 16A to the Progress Energy Consolidated Financial Statements, Progress Energy maintains qualified non-contributory defined benefit retirement (pension) plans. The Company's reported costs are dependent on numerous factors resulting from actual plan experience and assumptions of future experience. For example, such costs are impacted by employee demographics, changes made to plan provisions, actual plan asset returns and key actuarial assumptions such as expected long-term rates of return on plan assets and discount rates used in determining benefit obligations and annual costs.

Due to a slight decline in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate, the Company lowered the discount rate to 6.3% at December 31, 2003, which will increase the 2004 benefit costs recognized, all other factors remaining constant. However, after a few years of negative asset returns due to equity market declines, plan assets performed very well in 2003, with returns of approximately 30%. That positive asset performance will result in decreased pension cost in 2004. Evaluations of the effects of these factors have not been completed, but the Company estimates that the 2004 total cost recognized for pension will decrease by approximately $5 million from the amount recorded in 2003, due in large part to these factors.

The Company has pension plan assets, with a fair value of approximately $1.6 billion at December 31, 2003. The Company's expected rate of return on pension plan assets is 9.25%. The Company reviews this rate on a regular basis. Under Statement of Financial Accounting Standards No. 87, "Employer's Accounting for Pensions" (SFAS No. 87), the expected rate of return used in pension cost recognition is a long-term rate of return; therefore, the Company would only adjust that return if its fundamental assessment of the debt and equity markets changes or its investment policy changes significantly. The Company believes that its pension plans' asset investment mix and historical performance support the long-term rate of 9.25% being used. The Company did not adjust the rate in response to short-term market fluctuations such as the abnormally high market return levels of the latter 1990s, recent years' market declines and the market rebound in 2003. A 0.25% change in the expected rate of return for 2003 would have changed 2003 pension cost by approximately $4 million.

Another factor affecting the Company's pension cost and sensitivity of the cost to plan asset performance, is its selection of a method to determine the market-related value of assets, i.e., the asset value to which the 9.25% expected long-term rate of return is applied. SFAS No. 87 specifies that entities may use either fair value or an averaging method that recognizes changes in fair value over a period not to exceed five years, with the method selected applied on a consistent basis from year to year. The Company has historically used a five-year averaging method. When the Company acquired Florida Progress Corporation (Florida Progress) in 2000, it retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets. Changes in plan asset performance are reflected in pension cost sooner under the fair value method than the five-year averaging method and, therefore, pension cost tends to be more volatile using the fair value method. For example, in 2003 the expected return for assets subject to the averaging method was 3% lower than in 2002, whereas the expected return for assets subject to the fair value method was 18% lower than in 2002. Approximately 50% of the Company's pension plan assets is subject to each of the two methods.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Progress Energy is a registered holding company and, as such, has no operations of its own. As a holding company, Progress Energy's primary cash obligations are its common dividend and interest expense associated with $4.8 billion of senior unsecured debt. The ability to meet its obligations is primarily dependent on the earnings and cash flows of its two electric utilities and nonregulated subsidiaries, and the ability of those subsidiaries to pay dividends or repay funds to Progress Energy.

Other significant cash requirements of Progress Energy arise primarily from the capital-intensive nature of its electric utility operations as well as the expansion of its diversified businesses, primarily those of the Fuels segment.

Progress Energy relies upon its operating cash flow, generated primarily by its two regulated electric utility subsidiaries, commercial paper facilities and its ability to access long-term capital markets for its liquidity needs.

Since a substantial majority of Progress Energy's operating costs are related to its two regulated electric utilities, a significant portion of these costs are recovered from customers through fuel and energy cost recovery clauses.

As a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA), Progress Energy obtains approval from the SEC for the issuance and sale of securities as well as the establishment of intercompany extensions of credit (utility and nonutility money pools). PEC and PEF participate in the utility money pool, which allows the two utilities to lend and borrow between each other. Progress Energy can lend money into the utility money pool but cannot borrow funds. The nonutility money pool was established to allow Progress Energy's nonregulated operations to lend and borrow funds amongst each other. Progress Energy can also lend money to the nonutility money pool but cannot borrow funds.

During 2003, the Company realized approximately $450 million of net cash proceeds from the sale of NCNG and ENCNG. The Company also received net proceeds of approximately $97 million in October 2003 for the sale of its Mesa gas properties located in Colorado. Progress Energy used the proceeds from these sales to reduce indebtedness, primarily commercial paper, then outstanding.

On March 1, 2004, Progress Energy used available cash and proceeds from the issuance of commercial paper to retire $500 million 6.55% senior unsecured notes. Cash and commercial paper capacity were created primarily from the sale of the assets in 2003 as noted above.

For the 12 months ended December 31, 2003, the Company received approximately $309 million of net proceeds through the sale of 7.6 million shares of common stock issued through the Progress Energy Direct Stock Purchase and Dividend Reinvestment Plan, and its 401(k) Savings and Stock Ownership Plan. The Company expects to reduce the issuance of common stock in 2004.

Progress Energy's cash from operations and common stock issuances in 2004 is expected to fund its capital expenditures. To the extent necessary, incremental borrowings or commercial paper issuances may also be used as a source of liquidity.

Progress Energy believes its internal and external liquidity resources will be sufficient to fund its current business plans. Risk factors associated with commercial paper backup credit facilities and credit ratings are discussed below.

The following discussion of Progress Energy's liquidity and capital resources is on a consolidated basis.

Cash Flows from Operations

Cash from operations is the primary source used to meet operating requirements and capital expenditures. Total cash from operations for 2003 was $1.8 billion, compared to $1.6 billion in 2002. The increase in cash from operating activities for 2003 when compared with 2002 is largely the result of improved operating results at PEC. Total cash from operations for 2002 was $1.6 billion, up $271 million from 2001.

Progress Energy's two electric utilities produced over 90% of consolidated cash from operations in 2003. It is expected that the two electric utilities will continue to produce a majority of the consolidated cash flows from operations over the next several years as its nonregulated investments, primarily generation assets, improve asset utilization and begin generating operating cash flows.

In addition, Fuels' synthetic fuel operations do not currently produce positive operating cash flow primarily due to the difference in timing of when tax credits are recognized for financial reporting purposes and when tax credits are realized for tax purposes.

Total cash from operations provided the funding for approximately 90% of the Company's capital expenditures, including property additions, nuclear fuel expenditures and diversified business property additions during 2003, excluding proceeds from asset sales of $579 million. Progress Energy expects its operating cash flow to exceed its projected capital expenditures and common dividends beginning in 2004 and current plans are to use the excess cash flow to reduce debt.

Investing Activities

Excluding proceeds from sales of subsidiaries and investments, cash used in investing activities was $2.0 billion in 2003, down approximately $300 million when compared with 2002. The decrease is due primarily to lower utility property additions due to completion of Hines 2 construction at PEF and lower acquisitions of nonregulated assets.

Cash used in investing was $2.2 billion in 2002, up $562 million when compared with 2001. The increase was due primarily to PVI purchasing two generating projects from LG&E Energy Corp. for approximately $350 million.

Capital expenditures for Progress Energy's regulated electric operations were $1.0 billion or approximately 58% of consolidated capital expenditures in 2003, excluding proceeds from asset sales. As shown in the table below, the Company anticipates that the proportion of nonregulated capital spending to total capital expenditures will decrease substantially in 2004 when compared with

2003. The decrease reflects the completion of PVI's nonregulated generation portfolio in 2003. Progress Energy expects the majority of its capital expenditures to be incurred at its regulated operations. Forecasted nonregulated expenditures relate primarily to Progress Fuels and its gas operations, primarily for drilling new wells.

	Actual	Forecasted		
(in millions)	2003	2004	2005	2006
Regulated capital expenditures	$1,018	$980	$990	$1,020
Nuclear fuel expenditures	117	90	120	80
AFUDC — borrowed funds	(7)	(20)	(20)	(10)
Nonregulated capital expenditures	607	200	160	120
Total	$1,735	$1,250	$1,250	$1,210

Regulated capital expenditures in the table above include total expenditures from 2004 through 2006 of approximately $105 million expected to be incurred at PEC fossil-fueled electric generating facilities to comply with Section 110 of the Clean Air Act, referred to as the NOx SIP Call. See Note 21E to the Progress Energy Consolidated Financial Statements.

In June 2002, legislation was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from coal-fired power plants. PEC expects its capital costs to meet these emission targets will be approximately $813 million by 2013. For the years 2004 through 2006, the Company expects to incur approximately $320 million of total capital costs associated with this legislation, which is included in the table above. See Note 21E to the Progress Energy Consolidated Financial Statements and "Current Regulatory Environment" under "Other Matters" below for more information on this legislation.

In 2003, PEC determined that its external funding levels did not fully meet the nuclear decommissioning financial assurance levels required by the United States Nuclear Regulatory Commission (NRC). The funding levels had been adversely affected by the declines in the equity markets. The total shortfall was approximately $95 million (2010 dollars) for Robinson Unit No. 2, $82 million (2016 dollars) for Brunswick Unit No. 1 and $99 million (2014 dollars) for Brunswick Unit No. 2. PEC met the financial assurance requirements by obtaining a parent company guarantee. The funding status for these facilities would be positively affected by a continuing recovery in the equity markets and by the approval of license extension applications.

PEC retains funds internally to meet decommissioning liability. The NCUC order issued February 2004 found that by January 1, 2008, PEC must begin transitioning these amounts to external funds. The transition of $131 million must be completed by December 31, 2017, and at least 10% must be transitioned each year. PEC has exclusively utilized external funding for its decommissioning liability since 1994.

All projected capital and investment expenditures are subject to periodic review and revision and may vary significantly depending on a number of factors including, but not limited to, industry restructuring, regulatory constraints, market volatility and economic trends.

Financing Activities

Cash provided by operating activities and proceeds from asset sales exceeded property and fuel additions by approximately $625 million. The excess, when combined with $304 million of net cash generated from the sale of common stock, resulted in an increase of cash and cash equivalents of $212 million after paying common dividends. As of December 31, 2003, on a consolidated basis, the Company had $868 million of long-term debt maturing in 2004, $300 million of which was prefunded through issuances of long-term debt in 2003. On March 1, 2004, Progress Energy funded the maturity of its $500 million 6.55% senior unsecured notes with cash on hand and commercial paper.

On January 15, 2004, PEC funded the maturity of $150 million 5.875% First Mortgage Bonds with commercial paper proceeds. PEC also has $150 million 7.875% First Mortgage Bonds maturing on April 15, 2004. It plans to use commercial paper proceeds to fund this maturity.

During 2003, both PEC and PEF took advantage of historically low interest rates and refinanced several issues of debt.

In February 2003, PEF issued $425 million of First Mortgage Bonds, 4.80% Series, Due March 1, 2013, and $225 million of First Mortgage Bonds, 5.90% Series, Due March 1, 2033. Proceeds from this issuance were used to repay the balance of its outstanding commercial paper, to refinance its secured and unsecured indebtedness, including $150 million of PEF's First Mortgage Bonds, 8% Series, Due December 1, 2022, at 103.75% of the principal amount of such bonds.

On March 1, 2003, $70 million of PEF's First Mortgage Bonds, 6.125% Series, Due March 1, 2003, matured. PEF funded the maturity with commercial paper.

On May 27, 2003, PEC redeemed $150 million of First Mortgage Bonds, 7.5% Series, Due March 1, 2023, at

103.22% of the principal amount of such bonds. PEC funded the redemption with commercial paper.

On July 1, 2003, $110 million of PEF's First Mortgage Bonds, 6.0% Series, Due July 1, 2003, and $35 million of PEF's medium-term notes, 6.62% Series, matured. PEF funded the maturity with commercial paper.

On August 15, 2003, PEC redeemed $100 million of First Mortgage Bonds, 6.875% Series, Due August 15, 2023, at 102.84%. PEC funded the redemption with commercial paper.

On September 11, 2003, PEC issued $400 million of First Mortgage Bonds, 5.125% Series, Due September 15, 2013, and $200 million of First Mortgage Bonds, 6.125% Series, Due September 15, 2033. Proceeds from this issuance were used to reduce the balance of PEC's outstanding commercial paper and short-term notes payable to affiliated companies, which notes represent PEC's borrowings under the internal money pool operated by Progress Energy.

On November 21, 2003, PEF issued $300 million of First Mortgage Bonds, 5.10% Series, Due December 1, 2015. Proceeds from this issuance were used to refinance $100 million of PEF's First Mortgage Bonds, 7% Series, Due 2023, at 103.19% of the principal amount of such bonds, and to reduce the outstanding balance of its notes payable to affiliates.

The amount of debt issued by PEC and PEF in September and November, respectively, took into consideration debt maturities and other financing needs for 2004. As such, neither PEC nor PEF anticipate the need to issue long-term debt in 2004.

In March 2003, Progress Genco Ventures LLC (Genco), a wholly-owned subsidiary of PVI, terminated its $50 million working capital credit facility. Under a related construction facility, Genco has drawn $241 million at December 31, 2003.

During 2003, Progress Energy obtained a new three-year financing order which will expire September 30, 2006. Under the new order, Progress Energy, the holding company, can issue up to $2.8 billion of long-term securities, $1.5 billion of short-term debt and $3 billion of parent guarantees.

At December 31, 2003, the Company and its subsidiaries had committed lines of credit totaling $1.6 billion, for which there were no loans outstanding. All of the credit facilities supporting the $1.6 billion of credit were arranged through a syndication of commercial banks. There are no bilateral contracts associated with these facilities. These lines of credit support the Company's commercial paper borrowings. The following table summarizes the Company's credit facilities:

(in millions) Company	Description	Total
Progress Energy, Inc.	364-Day (expiring 11/10/04)	$250
Progress Energy, Inc.	3-Year (expiring 11/13/04)	450
Progress Energy Carolinas, Inc.	364-Day (expiring 7/29/04)	165
Progress Energy Carolinas, Inc.	3-Year (expiring 7/31/05)	285
Progress Energy Florida, Inc.	364-Day (expiring 3/31/04)	200
Progress Energy Florida, Inc.	3-Year (expiring 4/01/06)	200
Total credit facilities		$1,550

The Company's financial policy precludes issuing commercial paper in excess of its supporting lines of credit. At December 31, 2003, the Company did not have any commercial paper outstanding, leaving $1.6 billion available for issuance. In addition, the Company had requirements to pay minimal annual commitment fees to maintain its credit facilities. At December 31, 2002, the total amount of commercial paper outstanding was $695 million.

In addition, these credit agreements and Genco's $241 million bank facility contain various terms and conditions that could affect the Company's ability to borrow under these facilities. These include a maximum debt to total capital ratio, an interest coverage test, a material adverse change clause and cross-default provisions.

All of the credit facilities and Genco's bank facility include a defined maximum total debt to total capital ratio (leverage) and coverage ratios. At December 31, 2003, the calculated ratios for these four companies, pursuant to the terms of the agreements, are as follows:

Company	Maximum Leverage Ratio	Actual Leverage[a] Ratio	Minimum Coverage Ratio	Actual Coverage Ratio
Progress Energy, Inc.	68%	61.5%	2.5:1	3.74:1
Progress Energy Carolinas, Inc.	65%	51.4%	n/a	n/a
Progress Energy Florida, Inc.	65%	51.5%	3.0:1	9.22:1
Progress Genco Ventures, LLC	40%	24.6%	1.25:1	6.35:1

[a] *Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees which are not recorded on the Consolidated Balance Sheets.*

The credit facilities of Progress Energy, PEC, PEF and Genco include a provision under which lenders could refuse to advance funds in the event of a material adverse change in the borrower's financial condition.

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of $10 million. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of $10 million, the lenders could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. Progress Energy's cross-default provision only applies to Progress Energy and its significant subsidiaries (i.e., PEC, Florida Progress, PEF, Progress Capital Holdings, Inc. [PCH], PVI and Progress Fuels).

Additionally, certain of Progress Energy's long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of $25 million; these provisions only apply to other obligations of Progress Energy, primarily commercial paper issued by the holding company, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $4.3 billion in long-term debt, as of March 1, 2004. Certain agreements underlying the Company's indebtedness also limit its ability to incur additional liens or engage in certain types of sale and leaseback transactions.

The Company has on file with the SEC a shelf registration statement under which senior notes, junior debentures, common and preferred stock and other trust preferred securities are available for issuance by the Company. At December 31, 2003, the Company had approximately $1 billion available under this shelf registration.

Progress Energy and PEF each have an uncommitted bank bid facility authorizing each of them to borrow and re-borrow, and have loans outstanding at any time, up to $300 million and $100 million, respectively. At December 31, 2003, there were no outstanding loans against these facilities.

PEC currently has on file with the SEC a shelf registration statement under which it can issue up to $900 million of various long-term securities. PEF currently has on file registration statements under which it can issue an aggregate of $750 million of various long-term debt securities.

Both PEC and PEF can issue First Mortgage Bonds under their respective First Mortgage Bond indentures. At December 31, 2003, PEC and PEF could issue up to $2.8 billion and $3.4 billion based on property additions and $1.9 billion and $76 million based upon retirements.

The following table shows Progress Energy's capital structure at December 31, 2003 and 2002:

	2003	2002
Common Stock	40.6%	38.2%
Preferred Stock	0.5%	0.5%
Total Debt	58.9%	61.3%

The amount and timing of future sales of company securities will depend on market conditions, operating cash flow, asset sales and the specific needs of the Company. The Company may from time to time sell securities beyond the amount needed to meet capital requirements in order to allow for the early redemption of long-term debt, the redemption of preferred stock, the reduction of short-term debt or for other general corporate purposes.

Credit Rating Matters

The major credit rating agencies have currently rated the Company's securities as follows:

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Progress Energy, Inc.			
Corporate Credit Rating	n/a	BBB	n/a
Senior Unsecured	Baa2	BBB-	BBB-
Commercial Paper	P-2	A-2	n/a
Progress Energy Carolinas, Inc.			
Corporate Credit Rating	n/a	BBB	n/a
Commercial Paper	P-2	A-2	F2
Senior Secured Debt	A3	BBB	A-
Senior Unsecured Debt	Baa1	BBB	BBB+
Progress Energy Florida, Inc.			
Corporate Credit Rating	n/a	BBB	n/a
Commercial Paper	P-1	A-2	F2
Senior Secured Debt	A1	BBB	A-
Senior Unsecured Debt	A2	BBB	BBB+
FPC Capital I			
Preferred Stock*	Baa1	BB+	n/a
Progress Capital Holdings, Inc.			
Senior Unsecured Debt*	A3	BBB-	n/a

** Guaranteed by Florida Progress Corporation*

These ratings reflect the current views of these rating agencies and no assurances can be given that these ratings will continue for any given period of time. However, the Company monitors its financial condition as well as market conditions that could ultimately affect its credit ratings.

The Company and its subsidiaries' debt indentures and credit agreements do not contain any "ratings triggers," which would cause the acceleration of interest and principal payments in the event of a ratings downgrade.

However, in the event of a downgrade, the Company and/or its subsidiaries may be subject to increased interest costs on the credit facilities backing up the commercial paper programs. The Company and its subsidiaries have certain contracts which have provisions that are triggered by a ratings downgrade. These contracts include counterparty trade agreements, derivative contracts, certain Progress Energy guarantees and various types of third-party purchase agreements. None of these contracts would require any action on the part of Progress Energy or its subsidiaries unless the ratings downgrade results in a rating below investment grade.

The power supply agreement with Jackson Electric Membership Corporation that PVI acquired from Williams Energy Marketing and Trading Company included a performance guarantee that Progress Energy assumed. In the event that Progress Energy's credit ratings fall below investment grade, Progress Energy will be required to provide additional security for its guarantee in form and amount acceptable to Jackson.

In February 2003, Moody's Investors Service announced that it was lowering Progress Energy, Inc.'s senior unsecured debt rating from Baa1 to Baa2, and changing the outlook of the rating from negative to stable. Moody's cited the slower-than-planned pace of the Company's efforts to pay down debt from its acquisition of Florida Progress as the primary reason for the ratings change. Moody's also changed the outlook of PEF (A1 senior secured) and PCH (A3 senior unsecured) from stable to negative and lowered the trust preferred rating of FPC Capital I from A3 to Baa1 with a negative outlook.

Also in February 2003, Fitch Ratings Service assigned an initial rating to Progress Energy's senior unsecured debt of BBB-. No short-term rating was assigned.

Fitch also downgraded the ratings of PEF and PEC. PEF's senior secured rating was changed to A- from AA- and its senior unsecured rating was changed to BBB+ from A+. PEF's short-term rating was changed to F-2 from F-1+. PEC's senior secured rating was changed to A- from A+ and its senior unsecured rating was changed to BBB+ from A. PEC's short-term rating was changed to F-2 from F-1. Fitch's outlook for all three rated entities is stable.

In August 2003, Standard & Poor's (S&P) credit rating agency announced that it had lowered its corporate credit rating on Progress Energy Inc., PEC, PEF, and Florida Progress to BBB from BBB+. The outlook of the ratings was changed from negative to stable.

These changes have not had a material impact on the companies' access to capital or their financial results.

INTEREST RATE DERIVATIVES

Progress Energy uses interest rate derivative instruments to manage the fixed and variable rate debt components of its debt portfolio. The Company's long-term objective is to maintain a debt portfolio mix of approximately 30% variable rate debt, 70% fixed rate. At December 31, 2003, Progress Energy's variable rate and fixed rate debt comprised 16% and 84%, respectively, including the effects of interest rate derivatives.

During 2003, cash proceeds from the sale of NCNG and gas reserves were used to pay down debt, primarily commercial paper. While this reduced the Company's floating rate portion well below its long-term target of 30%, on March 1, 2004, the Company issued commercial paper to fund a portion of the maturing of $500 million, 6.55% senior unsecured notes, increasing the amount of floating rate debt back to over 20%.

Progress Fuels periodically enters into derivative instruments to hedge its exposure to price fluctuations on natural gas sales. At December 31, 2003, Progress Fuels had approximately 19 Bcf of cash flow hedges in place for its natural gas production. These positions extend through December 2005.

Genco has a floating rate credit facility that requires, as part of the loan terms, a cash flow hedge against floating interest rate exposure. In order to satisfy this requirement, Genco entered into a series of interest rate collars during 2002 with notional amounts up to a maximum of $195 million and a final maturity date of March 20, 2007.

CONTRACTUAL OBLIGATIONS

The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2003 in the respective periods in which they are due:

(in millions) Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt	$10,874	$868	$1,256	$1,742	$7,008
Capital lease obligations	50	4	8	7	31
Operating leases	307	38	60	41	168
Fuel and purchased power	10,683	1,672	1,976	1,312	5,723
Other purchase obligations	369	140	78	27	124
North Carolina clean air capital commitments	783	90	230	210	253
Funding obligations	182	51	—	13	118
Other commitments	111	26	52	33	—
Total	$23,359	$2,889	$3,660	$3,385	$13,425

Information on the Company's contractual obligations at December 31, 2003, is included in the notes to the Progress Energy Consolidated Financial Statements. Future debt maturities are included in Note 12 to the Progress Energy Consolidated Financial Statements. The Company's fuel and purchased power obligations have expiration dates ranging from 2004 to 2025 and are included in Note 21A to the Progress Energy Consolidated Financial Statements. The Company's other purchase obligations are included in Note 21A to the Progress Energy Consolidated Financial Statements. The Company's lease obligations are included in Note 21C to the Progress Energy Consolidated Financial Statements. PEC's North Carolina clean air legislation capital commitments are described in Note 21E to the Progress Energy Consolidated Financial Statements. In 2004, the Company expects to make $51 million of required contributions directly to retirement plan assets. Decommissioning cost provisions are included in Note 5D to the Progress Energy Consolidated Financial Statements. In 2008, PEC must begin transitioning amounts currently retained internally to its external decommissioning funds. The transition of $131 million must be complete by December 31, 2017, and at least 10% must be transitioned each year. The Company's other commitments are included in Note 21B to the Progress Energy Consolidated Financial Statements.

The Company takes into consideration the future commitments shown above when assessing its liquidity and future financing needs.

The Company's maturing debt obligations are generally expected to be refinanced with new debt issuances in the capital markets. However, the Company does plan to annually reduce its leverage by one to two percentage points over the next few years through the sale of assets and excess operating cash flow.

Fuel and purchased power commitments represent the majority of the Company's remaining future commitments after its debt obligations. Essentially all of the Company's fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.

OTHER MATTERS

Current Regulatory Environment

GENERAL

The Company's electric utility operations in North Carolina, South Carolina and Florida are regulated by the NCUC, the SCPSC and the FPSC, respectively. The electric businesses are also subject to regulation by the Federal Energy Regulatory Commission (FERC), the NRC and other federal and state agencies common to the utility business. In addition, the Company is subject to SEC regulation as a registered holding company under PUHCA. As a result of regulation, many of the fundamental business decisions, as well as the rate of return the electric utilities are permitted to earn, are subject to the approval of governmental agencies.

ELECTRIC INDUSTRY RESTRUCTURING

PEC and PEF continue to monitor any developments toward a more competitive environment and have actively participated in regulatory reform deliberations in North Carolina, South Carolina and Florida. Movement toward deregulation in these states has been affected by recent developments, including developments related to deregulation of the electric industry in other states. The Company expects the legislatures in all three states will continue to monitor the experiences of states that have implemented electric restructuring legislation.

The Company cannot anticipate when, or if, any of these states will move to increase competition in the electric industry.

FLORIDA RETAIL RATE PROCEEDING

In March 2002, the parties in PEF's rate case entered into a Stipulation and Settlement Agreement (the Agreement) related to retail rate matters. The Agreement was approved by the FPSC and is generally effective from May 1, 2002, through December 31, 2005; provided, however, that if PEF's base rate earnings fall below a 10% return on equity, PEF may petition the FPSC to amend its base rates. See Note 7D to the Progress Energy Consolidated Financial Statements for additional information on the Agreement.

NORTH CAROLINA CLEAN AIR LEGISLATION

In June 2002, legislation was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from coal-fired power plants. Progress Energy expects its capital costs to meet these emission targets to be approximately $813 million by 2013, of which approximately $30 million has been expended through December 31, 2003. PEC currently has approximately 5,100 MW of coal-fired generation in North Carolina that is affected by this legislation. The legislation requires the emissions reductions to be completed in phases by 2013, and applies to each utility's total system rather than setting requirements for individual power plants. The legislation also freezes the utilities' base rates for five years unless there are significant cost changes due to governmental action or other extraordinary events beyond the control of the utilities or unless the utilities

persistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the utilities' last general rate case. Further, the legislation allows the utilities to recover from their retail customers the projected capital costs during the first seven years of the 10-year compliance period beginning on January 1, 2003. The utilities must recover at least 70% of their projected capital costs during the five-year rate freeze period. Pursuant to the law, PEC entered into an agreement with the state of North Carolina to transfer to the state all future emissions allowances it generates from over-complying with the federal emission limits when these units are completed. The law also requires the state to undertake a study of mercury and carbon dioxide emissions in North Carolina. Operation and maintenance costs will increase due to the additional personnel, materials and general maintenance associated with the equipment. Operation and maintenance expenses are recoverable through base rates, rather than as part of this program. Progress Energy cannot predict the future regulatory interpretation, implementation or impact of this law.

FLORIDA PROPOSED CLEAN AIR LEGISLATION

In 2004, a bill was introduced in the Florida legislature that would require significant reductions in NOx, SO_2 and particulate emissions from certain coal, natural gas and oil-fired generating units owned or operated by investor-owned electric utilities, including PEF. The NOx and SO_2 reductions would be effective beginning with calendar year 2010, and the particulate reductions would be effective beginning with calendar year 2012. Under the proposed legislation, the FPSC would be authorized to allow the utilities to recover the costs of compliance with the emissions reductions over a period not greater than seven years beginning in 2005, but the utilities' rates would be frozen at 2004 levels for at least five years of the maximum recovery period. The Company cannot predict the outcome of this matter.

OTHER RETAIL RATE MATTERS

See Note 7B to the Progress Energy Consolidated Financial Statements for additional information on the Company's other retail rate matters.

REGIONAL TRANSMISSION ORGANIZATIONS AND STANDARD MARKET DESIGN

In 2000, the FERC issued Order 2000 regarding RTOs. This Order set minimum characteristics and functions that RTOs must meet, including independent transmission service. In July 2002, the FERC issued its Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR). If adopted as proposed, the rules set forth in the SMD NOPR would materially alter the manner in which transmission and generation services are provided and paid for. PEC and PEF, as subsidiaries of Progress Energy, filed comments in November 2002 and supplemental comments in January 2003. In April 2003, the FERC released a White Paper on the Wholesale Market Platform. The White Paper provides an overview of what the FERC currently intends to include in a final rule in the SMD NOPR docket. The White Paper retains the fundamental and most-protested aspects of SMD NOPR, including mandatory RTOs and the FERC's assertion of jurisdiction over certain aspects of retail service. The FERC has not yet issued a final rule on SMD NOPR. The Company cannot predict the outcome of these matters or the effect that they may have on the GridFlorida and GridSouth proceedings currently ongoing before the FERC. It is unknown what impact the future proceedings will have on the Company's earnings, revenues or prices. See Note 7C to the Progress Energy Consolidated Financial Statements for additional information on GridFlorida and GridSouth.

Franchise Litigation

Three cities, with a total of approximately 18,000 customers, have litigation pending against PEF in various circuit courts in Florida. Three other cities, with a total of approximately 30,000 customers, have subsequently settled their lawsuits with PEF and signed new, 30-year franchise agreements. The lawsuits principally seek 1) a declaratory judgment that the cities have the right to purchase PEF's electric distribution system located within the municipal boundaries of the cities, 2) a declaratory judgment that the value of the distribution system must be determined through arbitration, and 3) injunctive relief requiring PEF to continue to collect from PEF's customers and remit to the cities, franchise fees during the pending litigation, and as long as PEF continues to occupy the cities' rights-of-way to provide electric service, notwithstanding the expiration of the franchise ordinances under which PEF had agreed to collect such fees. Five circuit courts have entered orders requiring arbitration to establish the purchase price of PEF's electric distribution system within five cities. Two appellate courts have upheld those circuit court decisions and authorized cities to determine the value of PEF's electric distribution system within the cities through arbitration. Arbitration in one of the cases (the City of Casselberry) was held in August 2002. Following arbitration, the parties entered settlement discussions, and in July 2003, the City approved a settlement agreement and a new, 30-year franchise agreement with PEF. The

settlement resolves all pending litigation with that city. A second arbitration (with the 13,000-customer City of Winter Park) was completed in February 2003. That arbitration panel issued an award in May 2003 setting the value of PEF's distribution system within the City of Winter Park at approximately $32 million, not including separation and reintegration costs and construction work in progress, which could add several million dollars to the award. The panel also awarded PEF approximately $11 million in stranded costs. In September 2003, Winter Park voters passed a referendum that would authorize the City to issue bonds of up to approximately $50 million to acquire PEF's electric distribution system. The City has not yet definitively decided whether it will acquire the system, but has indicated that it will seek wholesale power supply bids and bids to operate and maintain the distribution system. At this time, whether and when there will be further proceedings regarding the City of Winter Park cannot be determined. A third arbitration (with the 2,500-customer Town of Belleair) was completed in June 2003. In September 2003, the arbitration panel issued an award in that case setting the value of the electric distribution system within the Town at approximately $6 million. The panel further required the Town to pay to PEF its requested $1 million in separation and reintegration costs and approximately $2 million in stranded costs. The Town has not yet decided whether it will attempt to acquire the system. At this time, whether and when there will be further proceedings regarding the Town of Belleair cannot be determined. A fourth arbitration (with the 13,000-customer City of Apopka) had been scheduled for January 2004. In December 2003, the Apopka City Commission voted on first reading to approve a settlement agreement and a 30-year franchise with PEF. The settlement and franchise became effective upon approval by the Commission at a second reading of the franchise in January 2004. The settlement resolves all outstanding litigation between the parties. Arbitration in the remaining city's litigation (the 1,500-customer City of Edgewood) has not yet been scheduled.

As part of the above litigation, two appellate courts have also reached opposite conclusions regarding whether PEF must continue to collect from its customers and remit to the cities "franchise fees" under the expired franchise ordinances. PEF has filed an appeal with the Florida Supreme Court to resolve the conflict between the two appellate courts. The Florida Supreme Court held oral argument in one of the appeals in August 2003. Subsequently, the Court requested briefing from the parties in the other appeal, which was completed in November 2003. The Court has not yet issued a decision in these cases. The Company cannot predict the outcome of these matters at this time.

Nuclear

In the Company's retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC, the SCPSC and the FPSC and are based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdictions, the provisions for nuclear decommissioning costs are approved by the FERC. See Note 5D to the Progress Energy Consolidated Financial Statements for a discussion of the Company's nuclear decommissioning costs.

Synthetic Fuels Tax Credits

Progress Energy, through the Fuels business segment, produces coal-based solid synthetic fuel. The production and sale of the synthetic fuel qualifies for tax credits under Section 29 if certain requirements are satisfied, including a requirement that the synthetic fuel differs significantly in chemical composition from the feedstock used to produce such synthetic fuel and that the fuel was produced from a facility that was placed in service before July 1, 1998. Any synthetic fuel tax credit amounts not utilized are carried forward indefinitely and are included in deferred taxes on the accompanying Consolidated Balance Sheets. See Note 14 to the Progress Energy Consolidated Financial Statements. All entities have received PLRs from the IRS with respect to their synthetic fuel operations. These tax credits are subject to review by the IRS, and if Progress Energy fails to prevail through the administrative or legal process, there could be a significant tax liability owed for previously taken Section 29 credits, with a significant impact on earnings and cash flows. Total Section 29 credits generated to date (including FPC prior to its acquisition by the Company) are approximately $1,243 million. The current Section 29 tax credit program expires at the end of 2007.

One of the Company's synthetic fuel entities, Colona Synfuel Limited Partnership, L.L.L.P. (Colona), from which the Company (and FPC prior to its acquisition by the Company) has been allocated approximately $317 million in tax credits to date, is being audited by the IRS. The Company is audited regularly in the normal course of business, as are most similarly situated companies, and the audit of Colona was expected.

In September 2002, all of Progress Energy's majority-owned synthetic fuel entities, including Colona, were accepted into the IRS Pre-Filing Agreement (PFA) program.

The PFA program allows taxpayers to voluntarily accelerate the IRS exam process in order to seek resolution of specific issues. Either the Company or the IRS can withdraw from the program at any time, and issues not resolved through the program may proceed to the next level of the IRS exam process.

In June 2003, the Company was informed that IRS field auditors had raised questions regarding the chemical change associated with coal-based synthetic fuel manufactured at its Colona facility and the testing process by which the chemical change is verified. (The questions arose in connection with the Company's participation in the PFA program.) The chemical change and the associated testing process were described as part of the PLR request for Colona. Based on that application, the IRS ruled in Colona's PLR that the synthetic fuel produced at Colona undergoes a significant chemical change and thus qualifies for tax credits under Section 29.

In October 2003, the National Office of the IRS informed the Company that it had rejected the IRS field auditors' challenges regarding whether the synthetic fuel produced at the Company's Colona facility was the result of a significant chemical change. The National Office had concluded that the experts engaged by Colona, who test the synthetic fuel for chemical change, use reasonable scientific methods to reach their conclusions. Accordingly, the National Office will not take any adverse action on the PLR that has been issued for the Colona facility.

Although this ruling applies only to the Colona facility, the Company believes that the National Office's reasoning would be equally applicable to the other Progress Energy facilities. The Company applies essentially the same chemical process and uses the same independent laboratories to confirm chemical change in the synthetic fuel manufactured at each of its other facilities.

In February 2004, subsidiaries of the Company finalized execution of the Colona Closing Agreement with the IRS concerning their Colona synthetic fuel facilities. The Colona Closing Agreement provided that the Colona facilities were placed in service before July 1, 1998, which is one of the qualification requirements for tax credits under Section 29. The Colona Closing Agreement further provides that the fuel produced by the Colona facilities in 2001 is a "qualified fuel" for purposes of the Section 29 tax credits. This action concludes the IRS PFA program with respect to Colona.

Although the execution of the Colona Closing Agreement is a significant event, the audits of the Company's facilities are not yet completed and the PFA process continues with respect to the four synthetic fuel facilities owned by other affiliates of Progress Energy and FPC. Currently, the focus of that process is to determine that the facilities were placed in service before July 1, 1998. In management's opinion, Progress Energy is complying with all the necessary requirements to be allowed such credits under Section 29, although it cannot provide with certainty that it will prevail if challenged by the IRS on credits taken. Accordingly, the Company has no current plans to alter its synthetic fuel production schedule as a result of these matters.

In October 2003, the United States Senate Permanent Subcommittee on Investigations began a general investigation concerning synthetic fuel tax credits claimed under Section 29. The investigation is examining the utilization of the credits, the nature of the technologies and fuels created, the use of the synthetic fuel, and other aspects of Section 29 and is not specific to the Company's synthetic fuel operations. Progress Energy is providing information in connection with this investigation. The Company cannot predict the outcome of this matter.

In addition, the Company has retained an advisor to assist in selling an interest in one or more synthetic fuel entities. The Company is pursuing the sale of a portion of its synthetic fuel production capacity that is underutilized due to limits on the amount of credits that can be generated and utilized by the Company. The Company would expect to retain an ownership interest and to operate any sold facility for a management fee. The final outcome and timing of these discussions is uncertain, and the Company cannot predict the outcome of this matter.

Environmental Matters

The Company is subject to federal, state and local regulations addressing air and water quality, hazardous and solid waste management and other environmental matters. These environmental matters are discussed in detail in Note 21E to the Progress Energy Consolidated Financial Statements. This discussion identifies specific environmental issues, the status of the issues, accruals associated with issue resolutions and the associated exposures to the Company.

New Accounting Standards

See Note 2 to the Progress Energy Consolidated Financial Statements for a discussion of the impact of new accounting standards.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk represents the potential loss arising from adverse changes in market rates and prices. Certain market risks are inherent in the Company's financial instruments, which arise from transactions entered into in the normal course of business. The Company's primary exposures are changes in interest rates with respect to its long-term debt and commercial paper, and fluctuations in the return on marketable securities with respect to its nuclear decommissioning trust funds. The Company manages its market risk in accordance with its established risk management policies, which may include entering into various derivative transactions.

These financial instruments are held for purposes other than trading. The risks discussed below do not include the price risks associated with nonfinancial instrument transactions and positions associated with the Company's operations, such as purchase and sales commitments and inventory.

Interest Rate Risk

The Company manages its interest rate risks through the use of a combination of fixed and variable rate debt. Variable rate debt has rates that adjust in periods ranging from daily to monthly. Interest rate derivative instruments may be used to adjust interest rate exposures and to protect against adverse movements in rates.

The following tables provide information at December 31, 2003 and 2002, about the Company's interest rate risk-sensitive instruments. The tables present principal cash flows and weighted-average interest rates by expected maturity dates for the fixed and variable rate long-term debt and FPC obligated mandatorily redeemable securities of trust. The tables also include estimates of the fair value of the Company's interest rate risk-sensitive instruments based on quoted market prices for these or similar issues. For interest rate swaps and interest rate forward contracts, the tables present notional amounts and weighted-average interest rates by contractual maturity dates. Notional amounts are used to calculate the contractual cash flows to be exchanged under the interest rate swaps and the settlement amounts under the interest rate forward contracts. See "Interest Rate Derivatives" under "Liquidity and Capital Resources" above for more information on interest rate derivatives.

December 31, 2003 *(dollars in millions)*	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value December 31, 2003
Fixed rate long-term debt	$868	$349	$909	$674	$827	$5,836	$9,463	$10,501
Average interest rate	6.67%	7.38%	6.78%	6.41%	6.27%	6.51%	6.55%	
Variable rate long-term debt	—	—	—	$241	—	$861	$1,102	$1,103
Average interest rate	—	—	—	3.04%	—	1.08%	1.51%	
Debt to affiliated trust	—	—	—	—	—	$309	$309	$313[d]
Interest rate	—	—	—	—	—	7.10%	7.10%	
Interest rate derivatives								
Pay variable/receive fixed[a]	—	—	$(300)	$(350)	$(200)	—	$(850)	$(4)
Payer swaptions[b]	—	—	—	—	$400	—	$400	$5
Interest rate collars[c]	$65	—	—	$130	—	—	$195	$(11)

[a] *Receives floating rate based on three-month London Inter Bank Offering Rate (LIBOR). Designated as hedge of $850 million of fixed-rate debt.*

[b] *PGN has the right to enter into a 3-year, pay-fixed swap beginning January 2005 at a fixed rate of 4.75%.*

[c] *Interest rate collars on $195 million notional. Designated as hedge of variable rate interest.*

[d] *Refer to Note 12F to the Progress Energy Consolidated Financial Statements.*

December 31, 2002 (dollars in millions)	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value December 31, 2002
Fixed rate long-term debt	$275	$869	$355	$909	$674	$5,614	$8,696	$9,584
Average interest rate	6.42%	6.66%	7.38%	6.78%	6.41%	6.90%	6.83%	—
Variable rate long-term debt	—	—	—	—	$225	$861	$1,086	$1,087
Average interest rate	—	—	—	—	0.03%	1.24%	1.61%	—
FPC mandatorily redeemable securities of trust	—	—	—	—	—	$300	$300	$303
Interest rate	—	—	—	—	—	7.10%	7.10%	—
Interest rate derivatives								
Pay variable/receive fixed[a]	—	—	—	—	$350	—	$350	$5
Interest rate forward contracts[b]	$35	—	—	—	—	—	$35	$(1)
Interest rate collars[c]	—	$65	—	—	$130	—	$195	$(12)

[a] *Receives fixed and pays floating rate based on three-month LIBOR.*
[b] *Treasury Rate Lock agreement on $35 million designated as cash flow hedge of anticipated debt issuance.*
[c] *Interest rate collars on $195 million notional. Designated as hedge of variable rate interest.*

Marketable Securities Price Risk

The Company's electric utility subsidiaries maintain trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning their nuclear plants. These funds are primarily invested in stocks, bonds and cash equivalents, which are exposed to price fluctuations in equity markets and to changes in interest rates. The fair value of these funds was $938 million and $797 million at December 31, 2003 and 2002, respectively. The Company actively monitors its portfolio by benchmarking the performance of its investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Company's regulated electric rates provide for recovery of these costs net of any trust fund earnings and, therefore, fluctuations in trust fund marketable security returns do not affect the earnings of the Company.

Contingent Value Obligations Market Value Risk

In connection with the acquisition of FPC, the Company issued 98.6 million Contingent Value Obligations (CVOs). Each CVO represents the right to receive contingent payments based on the performance of four synthetic fuel facilities purchased by subsidiaries of FPC in October 1999. The payments, if any, are based on the net after-tax cash flows the facilities generate. These CVOs are recorded at fair value and unrealized gains and losses from changes in fair value are recognized in earnings. At December 31, 2003 and 2002, the fair value of these CVOs was $23 million and $14 million, respectively. A hypothetical 10% decrease in the December 31, 2003, market price would result in a $2 million decrease in the fair value of the CVOs.

Commodity Price Risk

The Company is exposed to the effects of market fluctuations in the price of natural gas, electricity and other energy-related products marketed and purchased as a result of its ownership of energy-related assets. The Company's exposure to these fluctuations is significantly limited by the cost-based regulation of PEC and PEF. In addition, many of the Company's long-term power sales contracts shift substantially all fuel responsibility to the purchaser.

The Company uses natural gas hedging instruments to manage a portion of the market risk associated with fluctuations in the future sales price of the Company's natural gas. In addition, the Company may engage in limited economic hedging and trading activity using natural gas and electricity financial instruments. Refer to Note 17 to the Consolidated Financial Statements for additional information with regard to the Company's commodity contracts and use of derivative financial instruments.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The matters discussed throughout this Annual Report that are not historical facts are forward-looking and, accordingly, involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

In addition, examples of forward-looking statements discussed in this Annual Report include, but are not limited to, statements under the following headings: 1) "Liquidity and Capital Resources" about operating cash flows, estimated capital requirements through the year 2006 and future financing plans 2) "Strategy" about Progress Energy's strategy and 3) "Other Matters" about the effects of new environmental regulations, nuclear decommissioning costs and the effect of electric utility industry restructuring.

Any forward-looking statement speaks only as of the date on which such statement is made, and Progress Energy undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex government laws and regulations, including those relating to the environment; the impact of recent events in the energy markets that have increased the level of public and regulatory scrutiny in the energy industry and in the capital markets; deregulation or restructuring in the electric industry that may result in increased competition and unrecovered (stranded) costs; the uncertainty regarding the timing, creation and structure of regional transmission organizations; weather conditions that directly influence the demand for electricity; recurring seasonal fluctuations in demand for electricity; fluctuations in the price of energy commodities and purchased power; economic fluctuations and the corresponding impact on Progress Energy, Inc. and subsidiaries' (the Company) commercial and industrial customers; the ability of the Company's subsidiaries to pay upstream dividends or distributions to it; the impact on the facilities and the businesses of the Company from a terrorist attack; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the ability to successfully access capital markets on favorable terms; the impact that increases in leverage may have on the Company; the ability of the Company to maintain its current credit ratings; the impact of derivative contracts used in the normal course of business by the Company; investment performance of pension and benefit plans and the ability to control costs; the availability and use of Internal Revenue Code Section 29 (Section 29) tax credits by synthetic fuel producers, and the Company's continued ability to use Section 29 tax credits related to its coal and synthetic fuel businesses; the Company's ability to successfully integrate newly acquired assets, properties or businesses into its operations as quickly or as profitably as expected; the Company's ability to manage the risks involved with the operation of its nonregulated plants, including dependence on third parties and related counter-party risks, and a lack of operating history; the Company's ability to manage the risks associated with its energy marketing operations; and unanticipated changes in operating expenses and capital expenditures. Many of these risks similarly impact the Company's subsidiaries.

These and other risk factors are detailed from time to time in Progress Energy's United States Securities and Exchange Commission reports. All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond the control of Progress Energy. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can it assess the effect of each such factor on Progress Energy.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of Progress Energy, Inc.

We have audited the accompanying consolidated balance sheets of Progress Energy, Inc. and its subsidiaries at December 31, 2003 and 2002, and the related consolidated statements of income, changes in common stock equity and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 5F and 17A to the consolidated financial statements, in 2003, the Company adopted Statement of Financial Accounting Standards No. 143 and Derivatives Implementation Group Issue C20. As discussed in Note 8 to the consolidated financial statements, in 2002, the Company changed its method of accounting for goodwill to conform to Statement of Financial Accounting Standards No. 142.

Deloitte & Touche LLP

Raleigh, North Carolina
February 20, 2004

MANAGEMENT REPORT

The management of Progress Energy, Inc. is responsible for the information and representations contained in the financial statements and other sections of this annual report. The financial statements are prepared in conformity with accounting principles generally accepted in the United States of America, using informed judgments and estimates where appropriate. The information in other sections of this annual report is consistent with the financial statements.

The Company maintains a system of internal accounting controls to provide reasonable assurance that assets are safeguarded and the financial statements are reliable. This system is supported by our internal audit function.

The Board of Directors pursues its oversight role for financial reporting and accounting through its Audit Committee. The Committee, which is composed entirely of outside directors, meets periodically with management and the Company's internal and external auditors, who have free access to the Committee without management present, to discuss auditing, internal accounting and financial reporting matters.

The independent auditors, Deloitte & Touche LLP, are engaged to express an opinion on the Company's financial statements. Their opinion is based on procedures believed by them to be sufficient to provide reasonable assurance that the financial statements do not contain material misstatements.

Geoffrey S. Chatas

Geoffrey S. Chatas
Executive Vice President and Chief Financial Officer

CONSOLIDATED STATEMENTS OF INCOME

(in millions, except per share data) Years ended December 31	2003	2002	2001
Operating Revenues			
Utility	$6,741	$6,601	$6,557
Diversified business	2,002	1,490	1,572
Total Operating Revenues	8,743	8,091	8,129
Operating Expenses			
Utility			
Fuel used in electric generation	1,695	1,586	1,543
Purchased power	862	862	868
Operation and maintenance	1,419	1,390	1,228
Depreciation and amortization	883	820	1,067
Taxes other than on income	405	386	380
Diversified business			
Cost of sales	1,746	1,410	1,589
Depreciation and amortization	157	118	83
Impairment of long-lived assets	17	364	43
Other	197	145	92
Total Operating Expenses	7,381	7,081	6,893
Operating Income	1,362	1,010	1,236
Other Income (Expense)			
Interest income	11	15	22
Impairment of investments	(21)	(25)	(164)
Other, net	(25)	27	(34)
Total Other Income (Expense)	(35)	17	(176)
Interest Charges			
Net interest charges	632	641	690
Allowance for borrowed funds used during construction	(7)	(8)	(17)
Total Interest Charges, Net	625	633	673
Income from Continuing Operations before Income Tax and Cumulative Effect of Changes in Accounting Principles	702	394	387
Income Tax Benefit	(109)	(158)	(154)
Income from Continuing Operations before Cumulative Effect of Changes in Accounting Principles	811	552	541
Discontinued Operations, Net of Tax	(8)	(24)	1
Income before Cumulative Effect of Changes in Accounting Principles	803	528	542
Cumulative Effect of Changes in Accounting Principles, Net of Tax	(21)	—	—
Net Income	$782	$528	$542
Average Common Shares Outstanding	237	217	205
Basic Earnings per Common Share			
Income from Continuing Operations before Cumulative Effect of Changes in Accounting Principles	$3.42	$2.54	$2.64
Discontinued Operations, Net of Tax	(.03)	(.11)	.01
Cumulative Effect of Changes in Accounting Principles, Net of Tax	(.09)	—	—
Net Income	$3.30	$2.43	$2.65
Diluted Earnings per Common Share			
Income from Continuing Operations before Cumulative Effect of Changes in Accounting Principles	$3.40	$2.53	$2.63
Discontinued Operations, Net of Tax	(.03)	(.11)	.01
Cumulative Effect of Changes in Accounting Principles, Net of Tax	(.09)	—	—
Net Income	$3.28	$2.42	$2.64
Dividends Declared per Common Share	$2.26	$2.20	$2.14

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2003	2002
ASSETS		
Utility Plant		
Utility plant in service	$21,675	$20,157
Accumulated depreciation	(8,116)	(7,540)
Utility plant in service, net	13,559	12,617
Held for future use	13	15
Construction work in progress	634	752
Nuclear fuel, net of amortization	228	217
Total Utility Plant, Net	14,434	13,601
Current Assets		
Cash and cash equivalents	273	61
Accounts receivable	865	737
Unbilled accounts receivable	217	225
Inventory	808	875
Deferred fuel cost	317	184
Assets of discontinued operations	—	490
Prepayments and other current assets	348	262
Total Current Assets	2,828	2,834
Deferred Debits and Other Assets		
Regulatory assets	612	347
Nuclear decommissioning trust funds	938	797
Diversified business property, net	2,158	1,884
Miscellaneous other property and investments	464	519
Goodwill	3,726	3,719
Prepaid pension costs	462	60
Intangibles, net	327	155
Other assets and deferred debits	253	292
Total Deferred Debits and Other Assets	8,940	7,773
Total Assets	$26,202	$24,208
CAPITALIZATION AND LIABILITIES		
Common Stock Equity		
Common stock without par value, 500 million shares authorized, 246 and 238 million shares issued and outstanding, respectively	$5,270	$4,951
Unearned restricted shares (1 and 1 million shares, respectively)	(17)	(21)
Unearned ESOP shares (4 and 5 million shares, respectively)	(89)	(102)
Accumulated other comprehensive loss	(50)	(238)
Retained earnings	2,330	2,087
Total Common Stock Equity	7,444	6,677
Preferred Stock of Subsidiaries — Not Subject to Mandatory Redemption	93	93
Long-Term Debt Affiliate	309	—
Long-Term Debt	9,625	9,747
Total Capitalization	17,471	16,517
Current Liabilities		
Current portion of long-term debt	868	275
Accounts payable	704	659
Interest accrued	209	220
Dividends declared	140	132
Short-term obligations	4	695
Customer deposits	167	158
Liabilities of discontinued operations	—	125
Other current liabilities	572	430
Total Current Liabilities	2,664	2,694
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	737	858
Accumulated deferred investment tax credits	190	206
Regulatory liabilities	2,938	120
Cost of removal	—	2,940
Asset retirement obligations	1,271	—
Other liabilities and deferred credits	931	873
Total Deferred Credits and Other Liabilities	6,067	4,997
Commitments and Contingencies (Note 21)		
Total Capitalization and Liabilities	$26,202	$24,208

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions) Years ended December 31	2003	2002	2001
Operating Activities			
Net income	$782	$528	$542
Adjustments to reconcile net income to net cash provided by operating activities:			
Loss (income) from discontinued operations	8	24	(1)
Impairment of long-lived assets and investments	38	389	207
Cumulative effect of changes in accounting principles	21	—	—
Depreciation and amortization	1,146	1,099	1,266
Deferred income taxes	(276)	(402)	(367)
Investment tax credit	(16)	(18)	(23)
Deferred fuel cost (credit)	(133)	(37)	69
Cash provided (used) by changes in operating assets and liabilities:			
Accounts receivable	(168)	(35)	183
Inventories	78	(49)	(299)
Prepayments and other current assets	25	(39)	(21)
Accounts payable	41	100	(213)
Other current liabilities	167	56	123
Other	75	28	(93)
Net Cash Provided by Operating Activities	1,788	1,644	1,373
Investing Activities			
Gross utility property additions	(1,018)	(1,174)	(1,177)
Diversified business property additions	(607)	(570)	(350)
Nuclear fuel additions	(117)	(81)	(116)
Proceeds from sales of subsidiaries and investments	579	43	53
Acquisition of businesses, net of cash	—	(365)	—
Acquisition of intangibles	(200)	(10)	—
Other	(17)	(61)	(66)
Net Cash Used in Investing Activities	(1,380)	(2,218)	(1,656)
Financing Activities			
Issuance of common stock, net	304	687	488
Issuance of long-term debt, net	1,539	1,783	4,564
Net decrease in short-term indebtedness	(696)	(247)	(4,018)
Retirement of long-term debt	(810)	(1,157)	(322)
Dividends paid on common stock	(541)	(480)	(432)
Other	8	(5)	(42)
Net Cash Provided by (Used in) Financing Activities	(196)	581	238
Cash Used in Discontinued Operations	—	—	(1)
Net Increase (Decrease) in Cash and Cash Equivalents	212	7	(46)
Cash and Cash Equivalents at Beginning of Year	61	54	100
Cash and Cash Equivalents at End of Year	$273	$61	$54
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year			
Interest (net of amount capitalized)	$612	$631	$588
Income taxes (net of refunds)	$177	$219	$127

Noncash Activities

- In April 2002, Progress Fuels Corporation, a subsidiary of the Company, acquired 100% of Westchester Gas Company. In conjunction with the purchase, the Company issued approximately $129 million in common stock (See Note 4E).
- In December 2003, Progress Telecommunications Corporation (PTC) and Caronet, Inc., both indirect wholly-owned subsidiaries of Progress Energy, and EPIK Communications, Inc., a wholly-owned subsidiary of Odyssey Telecorp, Inc., contributed substantially all of their assets and transferred certain liabilities to Progress Telecom, LLC, a subsidiary of PTC (See Note 4A).

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS IN CHANGES OF COMMON STOCK EQUITY

(in millions, except per share data)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned Restricted Stock	Unearned ESOP Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Stock Equity
Balance, January 1, 2001	206	$3,621	$(13)	$(127)	$—	$1,943	$5,424
Net income						542	542
FAS 133 transition adjustment (net of tax of $15)					(24)		(24)
Change in net unrealized losses on cash flow hedges (net of tax of $13)					(21)		(21)
Reclassification adjustment for amounts included in net income (net of tax of $9)					14		14
Foreign currency translation and other					(1)		(1)
Comprehensive Income							510
Issuance of shares	13	489					489
Purchase of restricted stock			(8)				(8)
Restricted stock expense recognition			6				6
Cancellation of restricted shares		(1)	1				—
Allocation of ESOP shares		12		13			25
Dividends ($2.14 per share)						(442)	(442)
Balance, December 31, 2001	219	4,121	(14)	(114)	(32)	2,043	6,004
Net income						528	528
Change in net unrealized losses on cash flow hedges (net of tax of $18)					(28)		(28)
Reclassification adjustment for amounts included in net income (net of tax of $10)					16		16
Foreign currency translation and other					(2)		(2)
Minimum pension liability adjustment (net of tax of $121)					(192)		(192)
Comprehensive Income							322
Issuance of shares	19	815					815
Purchase of restricted stock			(16)				(16)
Restricted stock expense recognition			8				8
Cancellation of restricted shares		(1)	1				-
Allocation of ESOP shares		16		12			28
Dividends ($2.20 per share)						(484)	(484)
Balance, December 31, 2002	238	4,951	(21)	(102)	(238)	2,087	6,677
Net income						782	782
Change in net unrealized losses on cash flow hedges (net of tax of $7)					(12)		(12)
Reclassification adjustment for amounts included in net income (net of tax of ($11))					19		19
Foreign currency translation and other					4		4
Minimum pension liability adjustment (net of tax of ($112))					177		177
Comprehensive Income							970
Issuance of shares	8	309					309
Purchase of restricted stock		(1)	(7)				(8)
Restricted stock expense recognition			10				10
Cancellation of restricted shares		(1)	1				—
Allocation of ESOP shares		12		13			25
Dividends ($2.26 per share)						(539)	(539)
Balance, December 31, 2003	246	$5,270	$(17)	$(89)	$(50)	$2,330	$7,444

See Notes to Consolidated Financial Statements.

CONSOLIDATED QUARTERLY FINANCIAL DATA (UNAUDITED)

(in millions, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2003				
Operating revenues	**$2,187**	**$2,050**	**$2,458**	**$2,048**
Operating income	**357**	**274**	**478**	**253**
Income from continuing operations	**208**	**154**	**337**	**112**
Income before cumulative effect of changes in accounting principles	**218**	**157**	**318**	**110**
Net income	**219**	**157**	**318**	**88**
Common stock data				
Basic earnings per common share				
Income from continuing operations	**0.89**	**0.65**	**1.41**	**0.47**
Income before cumulative effect of changes in accounting principles	**0.94**	**0.67**	**1.33**	**0.46**
Net income	**0.94**	**0.67**	**1.33**	**0.37**
Diluted earnings per common share				
Income from continuing operations	**0.89**	**0.65**	**1.40**	**0.47**
Income before cumulative effect of changes in accounting principles	**0.93**	**0.66**	**1.33**	**0.46**
Net income	**0.94**	**0.66**	**1.33**	**0.37**
Dividends paid per common share	**0.560**	**0.560**	**0.560**	**0.560**
Market price per share				
High	**46.10**	**48.00**	**45.15**	**46.00**
Low	**37.45**	**38.99**	**39.60**	**41.60**
Year ended December 31, 2002				
Operating revenues	$1,813	$1,994	$2,316	$1,968
Operating income	244	306	201	259
Income from continuing operations	124	122	157	149
Net income	133	121	152	122
Common stock data				
Basic earnings per common share				
Income from continuing operations	0.58	0.57	0.72	0.66
Net income	0.62	0.56	0.71	0.55
Diluted earnings per common share				
Income from continuing operations	0.58	0.56	0.71	0.66
Net income	0.62	0.56	0.70	0.55
Dividends paid per common share	0.545	0.545	0.545	0.545
Market price per share				
High	50.86	52.70	51.97	44.82
Low	43.01	47.91	36.54	32.84

- In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. All amounts were restated for discontinued operations (See Note 3A) and 2003 amounts were restated for the cessation of reporting results for portions of the Fuels' segment operations one month in arrears (See Note 1B).
- Fourth quarter 2003 includes impairments related to Kentucky May and Affordable Housing investment of $38 million ($24 million after-tax) (See Note 9).
- Fourth quarter 2003 includes a cumulative effect for DIG Issue 20 of $38 million ($23 million after-tax) (See Note 17).
- Third quarter 2002 includes impairment and other charges related to PTC, Caronet and Interpath Communications, Inc. of $355 million ($225 million after-tax) (See Note 9).
- Fourth quarter 2002 includes estimated impairment of assets held for sale of Railcar Ltd. of $59 million ($40 million after-tax) (See Note 3B).

See Notes to Consolidated Financial Statements.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

Progress Energy, Inc. (Progress Energy or the Company) is a holding company headquartered in Raleigh, North Carolina. The Company is registered under the Public Utility Holding Company Act of 1935 (PUHCA), as amended and as such, the Company and its subsidiaries are subject to the regulatory provisions of PUHCA. Effective January 1, 2003, three of the Company's subsidiaries, Carolina Power & Light Company (CP&L), Florida Power Corporation and Progress Ventures, Inc., began doing business under the assumed names Progress Energy Carolinas, Inc. (PEC), Progress Energy Florida, Inc. (PEF) and Progress Energy Ventures, Inc. (PVI), respectively. The legal names of these entities have not changed. The current corporate and business unit structure remains unchanged.

Through its wholly-owned subsidiaries, PEC and PEF, the Company's PEC Electric and PEF segments are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. The Progress Ventures business unit consists of the Fuels business segment (Fuels) and Competitive Commercial Operations (CCO) operating segments. The Fuels segment is involved in natural gas drilling and production, coal terminal services, coal mining, synthetic fuel production, fuel transportation and delivery. The CCO segment includes nonregulated generation and energy marketing activities. Through the Rail Services (Rail) segment, the Company is involved in nonregulated railcar repair, rail parts reconditioning and sales, railcar leasing and sales, and scrap metal recycling. Through its other business units, the Company engages in other nonregulated business areas, including telecommunications and energy management and related services. Progress Energy's legal structure is not currently aligned with the functional management and financial reporting of the Progress Ventures business unit. Whether, and when, the legal and functional structures will converge depends upon legislative and regulatory action, which cannot currently be anticipated.

B. Basis of Presentation

The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the activities of the Company and its majority-owned subsidiaries. Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," which provides that profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of the sales price through the ratemaking process is probable.

Unconsolidated investments in companies over which the Company does not have control, but has the ability to exercise influence over operating and financial policies (generally 20%-50% ownership), are accounted for under the equity method of accounting. Certain investments in debt and equity securities that have readily determinable market values, and for which the Company does not have control, are accounted for at fair value in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Other investments are stated principally at cost. These equity and cost investments, which total approximately $57 million and $109 million at December 31, 2003 and 2002, respectively, are included in miscellaneous other property and investments in the Consolidated Balance Sheets. The primary component of this balance is the Company's investments in affordable housing of $29 million and $72 million at December 31, 2003 and 2002, respectively. This decrease is primarily due to the sale of certain PEC investments in the third quarter of 2003. For a discussion of how new FASB interpretations will affect these affordable housing investments, see Note 2.

The results of operations of Rail are reported one month in arrears. During 2003, the Company ceased recording portions of the Fuels' segment operations one month in arrears. The net impact of this action increased net income by $2 million for the year.

Certain amounts for 2002 and 2001 have been reclassified to conform to the 2003 presentation.

C. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

In preparing consolidated financial statements that conform with GAAP, management must make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the consolidated financial statements and amounts of revenues and expenses reflected during the reporting period. Actual results could differ from those estimates.

REVENUE RECOGNITION

The Company recognizes electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utility revenues earned when service has been delivered but not billed by the end of the accounting period. Diversified business revenues are generally recognized at the time products are shipped or as services are rendered. Leasing activities are accounted for in accordance with SFAS No. 13, "Accounting for Leases." Gains and losses from energy trading activities and other derivatives are reported on a net basis. Revenues related to design and construction of wireless infrastructure are recognized upon completion of services for each completed phase of design and construction. Revenues from the sale of oil and gas production are recognized when title passes, net of royalties.

FUEL COST DEFERRALS

Fuel expense includes fuel costs or recoveries that are deferred through fuel clauses established by the electric utilities' regulators. These clauses allow the utilities to recover fuel costs and portions of purchased power costs through surcharges on customer rates.

EXCISE TAXES

PEC and PEF collect from customers certain excise taxes levied by the state or local government upon the customers. PEC and PEF account for excise taxes on a gross basis. For the years ended December 31, 2003, 2002 and 2001, gross receipts tax, franchise taxes and other excise taxes of approximately $217 million, $211 million and $210 million, respectively, are included in taxes other than on income in the accompanying Consolidated Statements of Income. These approximate amounts are also included in utility revenues.

STOCK-BASED COMPENSATION

The Company measures compensation expense for stock options as the difference between the market price of its common stock and the exercise price of the option at the grant date. The exercise price at which options are granted by the Company equals the market price at the grant date, and accordingly, no compensation expense has been recognized for stock option grants. For purposes of the pro forma disclosures required by SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure — an Amendment of FASB Statement No. 123" (SFAS No. 148), the estimated fair value of the Company's stock options is amortized to expense over the options' vesting period. The following table illustrates the effect on net income and earnings per share if the fair value method had been applied to all outstanding and unvested awards in each period:

(in millions, except per share data)	2003	2002	2001
Net income, as reported	$782	$528	$542
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	11	8	2
Pro forma net income	$771	$520	$540
Earnings per share			
Basic — as reported	$3.30	$2.43	$2.65
Basic — pro forma	$3.25	$2.40	$2.64
Diluted — as reported	$3.28	$2.42	$2.64
Diluted — pro forma	$3.24	$2.39	$2.63

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. The Company capitalizes all construction-related direct labor and material costs of units of property as well as indirect construction costs. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property, and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal and decommissioning costs were charged to regulatory liabilities in 2003 and cost of removal in 2002. The Company follows the guidance in SFAS No. 143, "Accounting for Asset Retirement Obligations," to account for legal obligations associated with the retirement of certain tangible, long-lived assets.

DEPRECIATION AND AMORTIZATION — UTILITY PLANT

For financial reporting purposes, substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 5A). The North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (SCPSC) and the Florida Public Service Commission (FPSC) can also grant approval to accelerate or reduce depreciation and amortization of utility assets (See Note 7).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, is computed primarily on the units-of-production method and charged to fuel used in electric generation in the accompanying Consolidated Statements of Income. In the Company's retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC, the SCPSC and the FPSC and are

based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdictions, the provisions for nuclear decommissioning costs are approved by the Federal Energy Regulatory Commission (FERC).

CASH AND CASH EQUIVALENTS

The Company considers cash and cash equivalents to include unrestricted cash on hand, cash in banks and temporary investments purchased with a maturity of three months or less.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

The Company maintains an allowance for doubtful accounts receivable, which totaled approximately $28 million and $40 million at December 31, 2003 and 2002, respectively, and is included in accounts receivable on the Consolidated Balance Sheets.

INVENTORY

The Company accounts for inventory using the average-cost method.

REGULATORY ASSETS AND LIABILITIES

The Company's regulated operations are subject to SFAS No. 71, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, the Company records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the accompanying Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 7A).

DIVERSIFIED BUSINESS PROPERTY

Diversified business property is stated at cost less accumulated depreciation. If an impairment is recognized on an asset, the fair value becomes its new cost basis. The costs of renewals and betterments are capitalized. The cost of repairs and maintenance is charged to expense as incurred. Depreciation is computed on a straight-line basis using the estimated useful lives disclosed in Note 5B. Depletion of mineral rights is provided on the units-of-production method based upon the estimates of recoverable amounts of clean mineral.

The Company uses the full cost method to account for its natural gas and oil properties. Under the full cost method, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of natural gas and oil reserves are capitalized. These capitalized costs include the costs of all unproved properties, internal costs directly related to acquisition and exploration activities. The amortization base also includes the estimated future cost to develop proved reserves. Except for costs of unproved properties and major development projects in progress, all costs are amortized using the units-of-production method over the life of the Company's proved reserves.

GOODWILL AND INTANGIBLE ASSETS

Effective January 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), and no longer amortizes goodwill. Instead, goodwill is subject to at least an annual assessment for impairment by applying a two-step fair-value-based test. This assessment could result in periodic impairment charges. Prior to the adoption of SFAS No. 142, the Company amortized goodwill on a straight-line basis over a period not exceeding 40 years. Intangible assets are being amortized based on the economic benefit of their respective lives.

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

Long-term debt premiums, discounts and issuance expenses for the utilities are amortized over the life of the related debt using the straight-line method. Any expenses or call premiums associated with the reacquisition of debt obligations by the utilities are amortized over the applicable life using the straight-line method consistent with ratemaking treatment.

INCOME TAXES

The Company and its affiliates file a consolidated federal income tax return. Deferred income taxes have been provided for temporary differences. These occur when there are differences between the book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. Credits for the production and sale of synthetic fuel are deferred to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns.

DERIVATIVES

Effective January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138 and SFAS No. 149. SFAS No. 133, as

amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as assets or liabilities in the balance sheet and measure those instruments at fair value. During 2003, the Financial Accounting Standards Board (FASB) reconsidered an interpretation of SFAS No. 133. See Note 17 for the effect of the interpretation and additional information regarding risk management activities and derivative transactions.

ENVIRONMENTAL

The Company accrues environmental remediation liabilities when the criteria for SFAS No. 5, "Accounting for Contingencies" (SFAS No. 5), have been met. Environmental expenditures are expensed as incurred or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable (See Note 21E).

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

The Company reviews the recoverability of long-lived tangible and intangible assets whenever indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. The accounting for impairment of assets is based on SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which was adopted by the Company effective January 1, 2002. Prior to the adoption of this standard, impairments were accounted for under SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" (SFAS No. 121), which was superseded by SFAS No. 144.

The Company reviews its investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. The Company considers various factors, such as the investee's cash position, earnings and revenue outlook, liquidity and management's ability to raise capital in determining whether the decline is other-than-temporary. If the Company determines that an other-than-temporary decline exists in the value of its investments, it is the Company's policy to write-down these investments to fair value. See Note 9 for a discussion of impairment evaluations performed and charges taken.

Under the full cost method of accounting for natural gas and oil properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. If the ceiling (discounted revenues) is not equal to or greater than total capitalized costs, the Company is required to write-down capitalized costs to this level. The Company performs this ceiling test calculation every quarter. No write-downs were required in 2003, 2002 or 2001.

SUBSIDIARY STOCK TRANSACTIONS

Gains and losses realized as a result of common stock sales by the Company's subsidiaries are recorded in the Consolidated Statements of Income, except for any transactions that must be credited directly to equity in accordance with the provisions of SAB No. 51, "Accounting for Sales of Stock by a Subsidiary."

2. NEW ACCOUNTING STANDARDS

SFAS NO. 150, "ACCOUNTING FOR CERTAIN FINANCIAL INSTRUMENTS WITH CHARACTERISTICS OF BOTH LIABILITIES AND EQUITY"

In May 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity" (SFAS No. 150). The adoption of SFAS No. 150 did not have an impact on the Company's financial position or results of operations as of and for the periods ended December 31, 2003.

EITF ISSUE NO. 03-04, "ACCOUNTING FOR 'CASH BALANCE' PENSION PLANS"

In May 2003, the Emerging Issues Task Force (EITF) reached consensus in EITF Issue No. 03-04, "Accounting for 'Cash

Balance' Pension Plans" (EITF 03-04), to specifically address the accounting for certain cash balance pension plans. The consensus reached in EITF 03-04 requires certain cash balance pension plans to be accounted for as defined benefit plans. For cash balance plans described in EITF 03-04, the consensus also requires the use of the traditional unit credit method for purposes of measuring the benefit obligation and annual cost of benefits earned as opposed to the projected unit credit method. The Company has historically accounted for its cash balance plan as a defined benefit plan; however, the Company was required to adopt the measurement provisions of EITF 03-04 at its cash balance plan's measurement date of December 31, 2003. Any differences in the measurement of the obligations as a result of applying EITF 03-04 were reported as a component of actuarial gain or loss. The ongoing effects of this standard are dependent on other factors that also affect the determination of actuarial gains and losses and the subsequent amortization of such gains and losses. However, the adoption of EITF 03-04 is not expected to have a material effect on the Company's results of operations or financial position.

SFAS NO. 149, "AMENDMENT OF STATEMENT 133 ON DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES"

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." The statement amends and clarifies SFAS No. 133 on accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. The new guidance incorporates decisions made as part of the Derivatives Implementation Group (DIG) process, as well as decisions regarding implementation issues raised in relation to the application of the definition of a derivative. SFAS No. 149 is generally effective for contracts entered into or modified after June 30, 2003. Interpretations and implementation issues with regard to SFAS No. 149 continue to evolve. The statement had no significant impact on the Company's accounting for contracts entered into subsequent to the statement's effective date (See Note 17). Future effects, if any, on the Company's results of operations and financial condition will be dependent on the specifics of future contracts entered into with regard to guidance provided by the statement.

FIN NO. 46, "CONSOLIDATION OF VARIABLE INTEREST ENTITIES"

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities — an Interpretation of ARB No. 51" (FIN No. 46). This interpretation provides guidance related to identifying variable interest entities and determining whether such entities should be consolidated. FIN No. 46 requires an enterprise to consolidate a variable interest entity when the enterprise (a) absorbs a majority of the variable interest entity's expected losses, (b) receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Prior to the effective date of FIN No. 46, entities were generally consolidated by an enterprise that had control through ownership of a majority voting interest in the entity. FIN No. 46 originally applied immediately to variable interest entities created or obtained after January 31, 2003. During 2003, the Company did not participate in the creation of, or obtain a new variable interest in, any variable interest entity. In December 2003, the FASB issued a revision to FIN No. 46 (FIN No. 46R), which modified certain requirements of FIN No. 46 and allowed for the optional deferral of the effective date of FIN No. 46R until March 31, 2004. However, entities subject to FIN No. 46R that are deemed to be special-purpose entities (as defined in FIN No. 46R) must implement either FIN No. 46 or FIN No. 46R at December 31, 2003. The Company elected to apply FIN No. 46 to special-purpose entities as of December 31, 2003. Because the Company expects additional transitional guidance to be issued, it has elected to apply FIN No. 46R to non-special-purpose entities as of March 31, 2004.

Prior to the adoption of FIN No. 46, the Company consolidated the FPC Capital I trust (the Trust), which holds FPC-obligated mandatorily redeemable preferred securities. The Trust is a special-purpose entity as defined in FIN No. 46R, and therefore the Company applied FIN No. 46 to the Trust at December 31, 2003. The Trust is a variable interest entity, but the Company does not absorb a majority of the Trust's expected losses and therefore is not its primary beneficiary. Therefore, the Company deconsolidated the Trust at December 31, 2003. This deconsolidation resulted in recording an additional equity investment in the Trust of approximately $9 million, an increase in outstanding debt of approximately $8 million and a gain of approximately $1 million relating to the cumulative effect of a change in accounting principle. See Note 12F for a discussion of the Company's guarantees with the Trust.

The Company also has investments in 14 limited partnerships accounted for under the equity method for which it may be the primary beneficiary. These partnerships invest in and operate low-income housing and historical renovation properties that qualify for federal and state tax credits. The Company has not concluded whether it is the primary beneficiary of these partnerships. These partnerships

are partially funded with financing from third-party lenders, which is secured by the assets of the partnerships. The creditors of the partnerships do not have recourse to the Company. At December 31, 2003, the maximum exposure to loss as a result of the Company's investments in these limited partnerships was approximately $9 million. The Company expects to complete its evaluation of these partnerships under FIN No. 46R during the first quarter of 2004. If the Company had consolidated these 14 entities at December 31, 2003, it would have recorded an increase to both total assets and total liabilities of approximately $40 million.

The Company also has interests in several other variable interest entities created before January 31, 2003, for which the Company is not the primary beneficiary. These arrangements include equity investments in approximately 20 limited partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. The aggregate maximum loss exposure at December 31, 2003, under these arrangements totals approximately $34 million. The creditors of these variable interest entities do not have recourse to the general credit of the Company in excess of the aggregate maximum loss exposure.

In February 2004, the Company became aware that certain long-term purchase power and tolling contracts may be considered variable interests under FIN No. 46R. The Company has various long-term purchase power and tolling contracts with other utilities and certain qualifying facility plants. The Company believes the counterparties to these contracts are not special-purpose entities and therefore, FIN No. 46R would not apply to these contracts until March 31, 2004. The Company has not yet completed its evaluation of these contracts to determine if the Company needs to consolidate these counterparties under FIN No. 46R and will continue to monitor developing practice in this area.

3. DIVESTITURES

A. NCNG Divestiture

On September 30, 2003, the Company completed the sale of North Carolina Natural Gas Corporation (NCNG) and the Company's equity investment in Eastern North Carolina Natural Gas Company (ENCNG) to Piedmont Natural Gas Company, Inc. Net proceeds from the sale of NCNG of $443 million were used to reduce debt. Based on the net proceeds, the Company recorded an after-tax loss of $12 million during 2003.

The accompanying consolidated financial statements have been restated for all periods presented for the discontinued operations of NCNG. The net income of these operations is reported as discontinued operations in the Consolidated Statements of Income. Interest expense of $10 million, $16 million and $15 million for the years ended December 31, 2003, 2002 and 2001, respectively, has been allocated to discontinued operations based on the net assets of NCNG, assuming a uniform debt-to-equity ratio across the Company's operations. The Company ceased recording depreciation effective October 1, 2002, upon classification of the assets as discontinued operations. After-tax depreciation expense recorded by NCNG for each of the years ended December 31, 2002 and 2001, was $9 million and $10 million, respectively. Results of discontinued operations for years ended December 31 were as follows:

(in millions)	2003	2002	2001
Revenues	$284	$300	$321
Earnings before income taxes	$6	$9	$4
Income tax expense	2	4	3
Net earnings from discontinued operations	4	5	1
Loss on disposal of discontinued operations, including applicable income tax expense of $1 and $3, respectively	(12)	(29)	—
Earnings (loss) from discontinued operations	$(8)	$(24)	$1

The major balance sheet classes included in assets and liabilities of discontinued operations in the Consolidated Balance Sheets at December 31, 2002, are as follows:

(in millions)	
Utility plant, net	$399
Current assets	73
Deferred debits and other assets	18
Assets of discontinued operations	$490
Current liabilities	$76
Deferred credits and other liabilities	49
Liabilities of discontinued operations	$125

The sale of ENCNG resulted in net proceeds of $7 million and a pre-tax loss of $2 million, which is included in other, net on the accompanying Consolidated Statements of Income for the year ended December 31, 2003. The Company's equity investment in ENCNG of $8 million at December 31, 2002, is included in miscellaneous other property and investments in the accompanying Consolidated Balance Sheets.

B. Railcar Ltd. Divestiture

In December 2002, the Progress Energy Board of Directors adopted a resolution approving the sale of

Railcar Ltd., a subsidiary included in the Rail Services segment. In accordance with SFAS No. 144, an estimated pre-tax impairment of $59 million on assets held for sale was recognized in December 2002 to write-down the assets to fair value less costs to sell. This impairment has been included in impairment of long-lived assets in the Consolidated Statements of Income (See Note 9A).

The assets of Railcar Ltd. have been grouped as assets held for sale and are included in other current assets on the Consolidated Balance Sheets at December 31, 2003 and 2002. The assets were recorded at approximately $75 million and $24 million at December 31, 2003 and 2002, respectively, which reflects the Company's estimates of the fair value expected to be realized from the sale of these assets less costs to sell. The primary component of assets held for sale at December 31, 2003, was property and equipment of $74 million. The primary component of assets held for sale at December 31, 2002, was current assets of $22 million. The net increase in assets held for sale from December 31, 2002, to December 31, 2003, was primarily attributable to the purchase of railcars in 2003 that were subject to off-balance sheet obligations at December 31, 2002. In addition to the assets held for sale, the Company is subject to certain commitments under operating leases (See Note 21C).

In March 2003, the Company signed a letter of intent to sell the majority of Railcar Ltd. assets to The Andersons, Inc. In November 2003, the asset purchase agreement was signed, and the transaction closed in February 2004. Proceeds from the sale were approximately $82 million. The Company was relieved of the majority of the operating lease commitments when the assets were sold.

C. Mesa Hydrocarbons, Inc. Divestiture

In October 2003, the Company sold certain gas-producing properties owned by Mesa Hydrocarbons, LLC, a wholly-owned subsidiary of Progress Fuels Corporation (Progress Fuels), which is included in the Fuels segment. Net proceeds were approximately $97 million. Because the Company utilizes the full cost method of accounting for its oil and gas operations, the pre-tax gain of approximately $18 million was applied to reduce the basis of the Company's other U.S. oil and gas investments and will prospectively result in a reduction of the amortization rate applied to those investments as production occurs.

D. Inland Marine Transportation Divestiture

During 2001, the Company completed the sale of its Inland Marine Transportation business operated by MEMCO Barge Line, Inc., and related investments to AEP Resources, Inc., a wholly-owned subsidiary of American Electric Power, for a sales price of $270 million. Of the $270 million purchase price, $230 million was used to pay early termination of certain off-balance sheet arrangements for assets leased by the business. In connection with the sale, the Company entered into environmental indemnification provisions covering both known and unknown sites (See Note 21E). The Company adjusted the FPC purchase price allocation to reflect a $15 million net realizable value of the Inland Marine Transportation business.

E. Required Divestiture

The U.S. Securities and Exchange Commission's (SEC) original order approving the FPC merger required the Company to divest of Rail Services and certain immaterial, nonregulated investments of FPC by November 30, 2003. Although the Company has been actively marketing these investments, an acceptable divestiture opportunity was not found by that date. Therefore, the Company sought and in October 2003 was granted approval of a three-year extension from the SEC until 2006.

4. ACQUISITIONS AND BUSINESS COMBINATIONS

A. Progress Telecommunications Corporation

In December 2003, Progress Telecommunications Corporation (PTC) and Caronet, Inc. (Caronet), both wholly-owned subsidiaries of Progress Energy, and EPIK Communications, Inc. (EPIK), a wholly-owned subsidiary of Odyssey Telecorp, Inc. (Odyssey), contributed substantially all of their assets and transferred certain liabilities to Progress Telecom, LLC (PTC LLC), a subsidiary of PTC. Subsequently, the stock of Caronet was sold to an affiliate of Odyssey for $2 million in cash and Caronet became a wholly-owned subsidiary of Odyssey. Following consummation of all the transactions described above, PTC holds a 55% ownership interest in, and is the parent of PTC LLC. Odyssey holds a combined 45% ownership interest in PTC LLC through EPIK and Caronet. The accounts of PTC LLC are included in the Company's Consolidated Financial Statements since the transaction date. The minority interest is included in other liabilities and deferred credits in the Consolidated Balance Sheets.

The transaction was accounted for as a partial acquisition of EPIK through the issuance of the stock of a consolidated subsidiary. The contributions of PTC's and Caronet's net assets were recorded at their carrying values of approximately $31 million. EPIK's contribution was recorded at its estimated fair value of $22 million using the purchase method, and was initially allocated as follows: property

and equipment — $27 million; other current assets — $9 million; current liabilities — $21 million, and goodwill — $7 million. The goodwill was assigned to the Company's Other business segment and will not be deductible for tax purposes. The purchase price allocation is a preliminary estimate, based on available information, internal estimates and certain assumptions management believes are reasonable. Accordingly, the purchase price allocation is subject to finalization in 2004 pending the completion of internal and external appraisals of assets acquired. No gain or loss was recognized on the transaction. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for the years ended December 31, 2002 or 2001.

B. Acquisition of Natural Gas Reserves

During 2003, Progress Fuels entered into several independent transactions to acquire approximately 200 natural gas-producing wells with proven reserves of approximately 190 billion cubic feet (Bcf) from Republic Energy, Inc. and three other privately owned companies, all headquartered in Texas. The total cash purchase price for the transactions was $168 million.

C. Wholesale Energy Contract Acquisition

In May 2003, PVI entered into a definitive agreement with Williams Energy Marketing and Trading, a subsidiary of The Williams Companies, Inc., to acquire a long-term full-requirements power supply agreement at fixed prices with Jackson Electric Membership Corporation (Jackson), located in Jefferson, Georgia. The agreement calls for a $188 million cash payment to Williams Energy Marketing and Trading in exchange for assignment of the Jackson supply agreement. The $188 million cash payment was recorded as an intangible asset and is being amortized based on the economic benefit of the contract (See Note 8). The power supply agreement terminates in 2015, with a first-refusal right to extend for five years. The agreement includes the use of 640 megawatts (MW) of contracted Georgia System generation comprised of nuclear, coal, gas and pumped-storage hydro resources. PVI expects to supplement the acquired resources with its own intermediate and peaking assets in Georgia to serve Jackson's forecasted 1,100 MW peak demand in 2005 growing to a forecasted 1,700 MW demand by 2015.

D. Generation Acquisition

In February 2002, PVI acquired 100% of two electric generating projects located in Georgia from LG&E Energy Corp., a subsidiary of Powergen plc. The two projects consist of 1) Walton County Power, LLC in Monroe, Georgia, a 460 MW natural gas-fired plant placed in service in June 2001, and 2) Washington County Power, LLC in Washington County, Georgia, a 600 MW natural gas-fired plant placed in service in June 2003. The Walton and Washington projects have been accounted for using the purchase method of accounting and, accordingly, have been included in the consolidated financial statements since the acquisition date.

In the final allocation, the aggregate cash purchase price of approximately $348 million was allocated to diversified business property, intangibles and goodwill for $250 million, $33 million and $64 million, respectively (See Note 8). Of the acquired intangible assets, $33 million was assigned to tolling and power sale agreements with LG&E Energy Marketing, Inc. for each project and is being amortized through December 31, 2004. Goodwill was assigned to the CCO segment and will be deductible for tax purposes.

The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for the years ended December 31, 2002 or 2001.

E. Westchester Acquisition

In April 2002, Progress Fuels, a subsidiary of Progress Energy, acquired 100% of Westchester Gas Company (Westchester). The acquisition included approximately 215 natural gas-producing wells, 52 miles of intrastate gas pipeline and 170 miles of gas-gathering systems located within a 25-mile radius of Jonesville, Texas, on the Texas-Louisiana border.

The aggregate purchase price of approximately $153 million consisted of cash consideration of approximately $22 million and the issuance of 2.5 million shares of Progress Energy common stock then valued at approximately $129 million. The purchase price included approximately $2 million of direct transaction costs. The final purchase price was allocated to oil and gas properties, intangible assets, diversified business property, net working capital and deferred tax liabilities for approximately $152 million, $9 million, $32 million, $5 million and $45 million, respectively. The $9 million intangible assets recorded relate to customer contracts acquired as part of the acquisition and are being amortized over their respective lives (See Note 8).

The acquisition has been accounted for using the purchase method of accounting and, accordingly, the results of operations for Westchester have been included in Progress Energy's consolidated financial statements since the date of acquisition. The pro forma results of operations reflecting the acquisition would not be materially

different than the reported results of operations for the years ended December 31, 2002 or 2001.

5. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

The balances of electric utility plant in service at December 31 are listed below, with a range of depreciable lives for each:

(in millions)	2003	2002
Production plant (7-33 years)	$12,039	$11,063
Transmission plant (30-75 years)	2,167	2,104
Distribution plant (12-50 years)	6,432	6,073
General plant and other (8-75 years)	1,037	917
Utility plant in service	$21,675	$20,157

Generally, electric utility plant at PEC and PEF, other than nuclear fuel, is pledged as collateral for the first mortgage bonds of PEC and PEF, respectively.

Allowance for funds used during construction (AFUDC) represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 4.0% in 2003 and 6.2% in 2002 and 2001. The composite AFUDC rate for PEF's electric utility plant was 7.8% in 2003, 2002 and 2001.

Depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.5%, 2.6% and 2.8% in 2003, 2002 and 2001, respectively. The depreciation provisions related to utility plant were $517 million, $488 million and $530 million in 2003, 2002 and 2001, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, asset retirement obligation (ARO) accretion, cost of removal provisions (See Note 5D) and regulatory approved expenses (See Note 7).

PEC filed a new depreciation study in 2004 that provides support for reducing depreciation expense on an annual basis by approximately $45 million. The reduction is primarily attributable to assumption changes for nuclear generation, offset by increases for distribution assets. The new rates are primarily effective January 1, 2004.

Amortization of nuclear fuel costs, for the years ended December 31, 2003, 2002 and 2001, were $143 million, $141 million and $130 million, respectively.

B. Diversified Business Property

The balances of diversified business property at December 31 are listed below, with a range of depreciable lives for each:

(in millions)	2003	2002
Equipment (3-25 years)	$246	$299
Nonregulated generation plant and equipment (3-40 years)	1,299	549
Land and mineral rights	93	90
Buildings and plants (5-40 years)	153	153
Oil and gas properties (units-of-production)	412	265
Telecommunications equipment (5-20 years)	63	43
Rail equipment (3-20 years)	125	48
Marine equipment (3-35 years)	83	80
Computers, office equipment and software (3-10 years)	36	33
Construction work in progress	49	644
Accumulated depreciation	(401)	(320)
Diversified business property, net	$2,158	$1,884

The Company's nonregulated businesses capitalize interest costs under SFAS No. 34, "Capitalizing Interest Costs." During the years ended December 31, 2003 and 2002, respectively, the Company capitalized $20 million and $38 million of its interest expense of $652 million and $679 million related to the expansion of its nonregulated generation portfolio at PVI. Capitalized interest is included in diversified business property, net on the Consolidated Balance Sheets. Diversified business depreciation expense was $120 million, $85 million and $61 million for December 31, 2003, 2002 and 2001, respectively.

C. Joint Ownership of Generating Facilities

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. PEC's and PEF's share of expenses for the jointly owned facilities is included in the appropriate expense category. The co-owner of Intercession City Unit P11 (P11) has exclusive rights to the output of the unit during the months of June through September. PEF has that right for the remainder of the year. PEC's and PEF's ownership interests in the jointly owned generating facilities are listed below with related information at December 31, ($ in millions):

2003 Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo Plant	83.83%	$464	$242	$50
PEC	Harris Plant	83.83%	3,248	1,370	7
PEC	Brunswick Plant	81.67%	1,611	884	21
PEC	Roxboro Unit 4	87.06%	323	139	1
PEF	Crystal River Unit 3	91.78%	1,069	432	49
PEF	Intercession City Unit P11	66.67%	22	6	6

2002 Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo Plant	83.83%	$464	$232	$14
PEC	Harris Plant	83.83%	3,160	1,331	6
PEC	Brunswick Plant	81.67%	1,477	811	26
PEC	Roxboro Unit 4	87.06%	316	134	8
PEF	Crystal River Unit 3	91.78%	777	375	28
PEF	Intercession City Unit P11	66.67%	22	5	4

In the tables above, plant investment and accumulated depreciation are not reduced by the regulatory disallowances related to the Shearon Harris Nuclear Plant (Harris Plant).

D. Decommissioning, Dismantlement and Cost of Removal Provisions

Decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million, $31 million and $39 million in 2003, 2002 and 2001, respectively. The PEF rate case settlement required PEF to suspend accruals on its reserves for nuclear decommissioning and fossil dismantlement through December 31, 2005 (See Note 7D). Management believes that decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning.

PEF's provision for fossil plant dismantlement was previously suspended per a 1997 FPSC settlement agreement, but resumed mid-2001. The 2001 annual provision, approved by the FPSC, was $9 million. The accrual for fossil dismantlement reserves was suspended again in 2002 by the Florida rate case settlement (See Note 7D).

Cost of removal provisions, which are included in depreciation and amortization expense were $158 million, $149 million and $143 million in 2003, 2002 and 2001, respectively. These amounts represent the expense recognized for the disposal or removal of utility assets. The FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), that changed the accounting for the decommissioning, dismantlement and cost of removal provisions (See Note 5F).

E. Insurance

PEC and PEF are members of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities. Under the primary program, each company is insured for $500 million at each of its respective nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $2.0 billion on the Brunswick and Harris Plants, and $1.1 billion on the Robinson and Crystal River Unit No. 3 (CR3) Plants.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured thereunder, following a 12-week deductible period, for 52 weeks in the amount of $3 million per week at the Brunswick and Harris Plants, $2.5 million per week at the Robinson Plant and $4.5 million per week at the CR3 Plant. An additional 110 weeks of coverage is provided at 80% of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $27 million with respect to the primary coverage, $31 million with respect to the decontamination, decommissioning and excess property coverage, and $19 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the United States Nuclear Regulatory Commission (NRC), each company's

property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both PEC and PEF are insured against public liability for a nuclear incident up to $10.9 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from an insured nuclear incident exceed $300 million (currently available through commercial insurers), each company would be subject to pro rata assessments of up to $101 million for each reactor owned per occurrence. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $10 million per reactor owned. Congress is expected to approve revisions to the Price Anderson Act during 2004 that could include increased limits and assessments per reactor owned. The final outcome of this matter cannot be predicted at this time.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.2 billion, along with any amounts it recovers from reinsurance, government indemnity or other sources up to the limits for each claimant. If terrorism losses occurred beyond the one-year period, a new set of limits and resources would apply. For nuclear liability claims arising out of terrorist acts, the primary level available through commercial insurers is now subject to an industry aggregate limit of $300 million. The second level of coverage obtained through the assessments discussed above would continue to apply to losses exceeding $300 million and would provide coverage in excess of any diminished primary limits due to the terrorist acts aggregate.

PEC and PEF self-insure their transmission and distribution lines against loss due to storm damage and other natural disasters. PEF accrues $6 million annually to a storm damage reserve pursuant to a regulatory order and may defer losses in excess of the reserve (See Note 7A).

F. Asset Retirement Obligations

SFAS No. 143 provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and was adopted by the Company effective January 1, 2003. This statement requires that the present value of retirement costs for which the Company has a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. Cumulative accretion and accumulated depreciation were recognized for the time period from the date the liability would have been recognized had the provisions of this statement been in effect, to the date of adoption of this statement. For assets acquired through acquisition, the cumulative effect was based on the acquisition date.

Upon adoption of SFAS No. 143, the Company recorded AROs totaling $1,183 million for nuclear decommissioning of irradiated plants at PEC and PEF. The Company used an expected cash flow approach to measure these obligations. This amount includes accruals recorded prior to adoption totaling $775 million, which were previously recorded in cost of removal. The related asset retirement costs, net of accumulated depreciation, recorded upon adoption totaled $368 million for regulated operations. The adoption of this statement had no impact on the income of the regulated entities, as the effects were offset by the establishment of a regulatory asset and a regulatory liability pursuant to SFAS No. 71. A regulatory asset was recorded related to PEC in the amount of $271 million, representing the cumulative accretion and accumulated depreciation for the time period from the date the liability would have been recognized had the provisions of this statement been in effect to the date of adoption, less amounts previously recorded. A regulatory liability was recorded related to PEF in the amount of $231 million, representing the amount by which previously recorded accruals exceeded the cumulative accretion and accumulated depreciation for the time period from the date the liability would have been recognized had the provisions of this statement been in effect at the date of the acquisition of the assets by Progress Energy to the date of adoption.

At December 31, 2003, the asset retirement costs related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $354 million for regulated operations. The ongoing expense differences between SFAS No. 143 and regulatory cost recovery are being deferred to the regulatory asset and regulatory liability.

Funds set aside in the Company's nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $938 million at December 31, 2003, and $797 million at December 31, 2002. Net unrealized gains on the nuclear decommissioning trust funds were included in regulatory liabilities in 2003 and cost of removal in 2002.

Upon adoption of SFAS No. 143, the Company also recorded AROs totaling $10 million for synthetic fuel operations of PVI and coal mine operations, synthetic fuel operations and gas production of Progress Fuels. The Company used an expected cash flow approach to measure these obligations. This amount includes accruals recorded prior to adoption totaling $5 million, which was previously recorded in other liabilities and deferred credits. The related asset retirement costs, net of accumulated depreciation, recorded upon adoption totaled $7 million for nonregulated operations. The cumulative effect of initial adoption of this statement related to nonregulated operations was $1 million of income, which is included in cumulative effect of changes in accounting principles, net of tax on the Consolidated Statements of Income for the year ended December 31, 2003.

The AROs for synthetic fuel operations of PVI and coal mine operations, synthetic fuel operations and gas production of Progress Fuels totaled $20 million at December 31, 2003. The related asset retirement costs, net of accumulated depreciation, totaled $7 million for nonregulated operations at December 31, 2003. The following table shows the changes to the asset retirement obligations during the year ended December 31, 2003. Additions relate primarily to additional reclamation obligations at coal mine operations of Progress Fuels.

(in millions)	*Regulated*	*Nonregulated*
Asset retirement obligations as of January 1, 2003	$1,183	$10
Additions	—	11
Accretion expense	68	1
Deductions	—	(2)
Asset retirement obligations as of December 31, 2003	$1,251	$20

Pro forma net income has not been presented for prior years because the pro forma application of SFAS No. 143 to prior years would result in pro forma net income not materially different from the actual amounts reported.

The Company has identified but not recognized AROs related to electric transmission and distribution and telecommunications assets as the result of easements over property not owned by the Company. These easements are generally perpetual and only require retirement action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as the Company intends to utilize these properties indefinitely. In the event the Company decides to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time.

The utilities previously recognized removal, decommissioning and dismantlement costs as a component of accumulated depreciation in accordance with the regulatory treatment. At December 31, 2003, such costs totaling $2,169 million were included in regulatory liabilities on the Consolidated Balance Sheets and consist of removal costs of $1,897 million, removal costs for nonirradiated areas at nuclear facilities of $129 million and amounts previously collected for dismantlement of fossil generation plants of $143 million. At December 31, 2002, such costs totaling $2,940 million were included in cost of removal on the Consolidated Balance Sheets and consist of removal costs of $1,790 million, decommissioning costs for both the irradiated and nonirradiated areas at nuclear facilities of $1,008 million and amounts previously collected for dismantlement of fossil generation plants of $142 million. With the adoption of SFAS No. 143 in 2003, removal costs related to the irradiated areas at nuclear facilities are reported as asset retirement obligations on the 2003 Consolidated Balance Sheet.

PEC filed a request with the NCUC requesting deferral of the difference between expense pursuant to SFAS No. 143 and expense as previously determined by the NCUC. The NCUC initially granted the deferral of the January 1, 2003, cumulative adjustment. During the third quarter of 2003, the NCUC issued an order allowing the deferral of the ongoing effects of SFAS No. 143. In April 2003, the SCPSC approved a joint request by PEC, Duke Energy Corporation and South Carolina Electric and Gas Company for an accounting order to authorize the deferral of all cumulative and prospective effects related to the adoption of SFAS No. 143. Therefore, SFAS No. 143 had no impact on the income of PEC for the year ended December 31, 2003.

In January 2003, the Staff of the FPSC issued a notice of proposed rule development to adopt provisions relating to accounting for asset retirement obligations under SFAS No. 143. Accompanying the notice was a draft rule presented by the Staff which adopts the provisions of SFAS No. 143 along with the requirement to record the difference between amounts prescribed by the FPSC and those used in the application of SFAS No. 143 as regulatory assets or regulatory liabilities, which was accepted by all parties. A final order was issued in the third quarter of 2003. Therefore, the adoption of the statement had no impact on the income of PEF due to the establishment of a regulatory liability pursuant to SFAS No. 71.

6. INVENTORY

At December 31, inventory was comprised of:

(in millions)	2003	2002
Fuel	$250	$313
Rail equipment and parts	132	155
Materials and supplies	386	363
Other	40	44
Total inventory	$808	$875

7. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As regulated entities, the utilities are subject to the provisions of SFAS No. 71. Accordingly, the utilities record certain assets and liabilities resulting from the effects of the ratemaking process which would not be recorded under GAAP for nonregulated entities. The utilities' ability to continue to meet the criteria for application of SFAS No. 71 may be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS No. 71 no longer applied to a separable portion of the Company's operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, these factors could result in an impairment of utility plant assets as determined pursuant to SFAS No. 144.

At December 31, the balances of regulatory assets (liabilities) were as follows:

(in millions)	2003	2002
Deferred fuel cost	$317	$184
Deferred impact of ARO (Note 5F)	291	—
Income taxes recoverable through future rates (Note 14)	136	155
Deferred purchased power contract termination costs (Note 7B)	—	47
Loss on reacquired debt (Note 1C)	55	33
Deferred DOE enrichment facilities-related costs (Note 1C)	24	31
Storm deferral (Note 7B)	21	—
Other postretirement benefits (Note 16B)	9	11
Other	76	70
Total long-term regulatory assets	612	347
Non-ARO cost of removal (Note 5F)	(2,169)	—
Deferred impact of ARO (Note 5F)	(212)	—
Net nuclear decommissioning trust unrealized gains (Note 5F)	(204)	—
Defined benefit retirement plan (Note 16B)	(211)	(51)
Storm reserve (Note 5E)	(41)	(36)
Clean air compliance (Note 7B)	(74)	—
Other	(27)	(33)
Total long-term regulatory liabilities	(2,938)	(120)
Net regulatory assets (liabilities)	$(2,009)	$411

Except for portions of deferred fuel, all regulatory assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. The Company expects to fully recover these assets and refund the liabilities through customer rates under current regulatory practice.

B. Retail Rate Matters

The NCUC and SCPSC have approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The aggregate minimum and maximum amounts of cost recovery are $530 million and $750 million, respectively. Accelerated cost recovery of these assets resulted in no additional expense in 2003 and additional depreciation expense of approximately $53 million and $75 million in 2002 and 2001, respectively. Total accelerated depreciation recorded through December 31, 2003, was $403 million.

In compliance with a regulatory order, PEF accrues a reserve for maintenance and refueling expenses anticipated to be incurred during scheduled nuclear plant outages.

In conjunction with the acquisition of NCNG in 1999, PEC agreed to cap base retail electric rates in North Carolina and South Carolina through December 2004. The cap on base retail electric rates in South Carolina was extended to December 2005 in conjunction with regulatory approval to form a holding company.

The NC Clean Air Act of June 2002 (the Clean Air Act), requires state utilities to reduce emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from coal-fired plants. The NCUC has allowed the utilities to amortize and recover the costs associated with meeting the new emission standards over a seven-year period beginning January 1, 2003. PEC recognized $74 million of clean air amortization during 2003. This legislation freezes PEC's base rates in North Carolina for five years, subject to certain conditions (See Note 21E).

In conjunction with the FPC merger, PEC reached a settlement with the Public Staff of the NCUC in which it agreed to provide credits to its non-real-time-pricing customers in the amounts of $3 million in 2002, $5 million in 2003 and $6 million in both 2004 and 2005.

At December 31, 2000, PEF, with the approval of the FPSC, had established a regulatory liability to defer $63 million of revenues. In 2001, PEF applied the deferred revenues, plus accrued interest, to reduce its regulatory asset related to deferred purchased power termination costs. In addition, PEF recorded accelerated amortization of $34 million to further offset this regulatory asset during 2001. During 2003, PEF fully amortized this regulatory asset.

In February 2003, PEF petitioned the FPSC to increase its fuel factors due to continuing increases in oil and natural gas commodity prices. In March 2003, the FPSC approved PEF's petition. New rates also became effective in March 2003.

In September 2003, PEF asked the FPSC to approve a cost adjustment in its annual fuel filing, primarily related to rising costs of fuel that will increase retail customer bills beginning January 1, 2004. The total amount of the fuel adjustment requested above current levels was approximately $322 million. In November 2003, the FPSC approved PEF's request and new rates became effective January 2004.

PEC obtained SCPSC and NCUC approval of fuel factors in annual fuel-adjustment proceedings. The SCPSC approved PEC's petition to leave billing rates unchanged from the prior year by order issued in March 2003. The NCUC approved an increase of $20 million by order issued in September 2003.

In October 2003, PEC made a filing with the NCUC to seek permission to defer expenses incurred from Hurricane Isabel and the February 2003 winter storms. As a result of rising storm costs and the frequency of major storm damage, PEC asked the NCUC to allow PEC to create a deferred account in which PEC would place expenses incurred as a result of named tropical storms, hurricanes and significant winter storms. In December 2003, the NCUC approved PEC's request to defer the costs and amortize them over a period of five years beginning in the month the storm occurs. PEC charged approximately $24 million in 2003 from Hurricane Isabel and from current year ice storms to the deferred account, of which $3 million was amortized during 2003.

PEC retains funds internally to meet decommissioning liability. The NCUC order issued February 2004 found that by January 1, 2008, PEC must begin transitioning these amounts to external funds. The transition of $131 million must be completed by December 31, 2017, and at least 10% must be transitioned each year. PEC has exclusively utilized external funding for its decommissioning liability since 1994.

C. Regional Transmission Organizations and Standard Market Design

In 2000, the FERC issued Order 2000 regarding regional transmission organizations (RTOs). This Order set minimum characteristics and functions that RTOs must meet, including independent transmission service (ISOs). In July 2002, the FERC issued its Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR). If adopted as proposed, the rules set forth in the SMD NOPR would materially alter the manner in which transmission and generation services are provided and paid for. PEC and PEF, as subsidiaries of Progress Energy, filed comments in November 2002 and supplemental comments in January 2003. In April 2003, the FERC released a White Paper on the Wholesale Market Platform. The White Paper provides an overview of what the FERC currently intends to include in a final rule in the SMD NOPR docket. The White Paper retains the fundamental and most protested aspects of SMD NOPR, including mandatory RTOs and the FERC's assertion of jurisdiction over certain aspects of retail service. The FERC has not yet issued a final rule on SMD NOPR. The Company cannot predict the outcome of these matters or the effect that they may have on the GridFlorida and GridSouth proceedings currently ongoing before the FERC. It is unknown what impact the future proceedings will have on the Company's earnings, revenues or prices.

The Company has $33 million and $4 million invested in GridSouth and GridFlorida, respectively, at December 31, 2003. Given the regulatory uncertainty of the ultimate timing, structure and operations of GridSouth, GridFlorida or an alternate combined transmission structure, the Company cannot predict the effect on future consolidated results of operations, cash flows or financial condition. Furthermore, the SMD NOPR presents several uncertainties, including what percentage of the investments in GridSouth and GridFlorida will be recovered, how the elimination of transmission charges, as proposed in the SMD NOPR, will impact the Company, and what amount of capital expenditures will be necessary to create a new wholesale market.

D. PEF Rate Case Settlement

The FPSC initiated a rate proceeding in 2001 regarding PEF's future base rates. In March 2002, the parties in PEF's rate case entered into a Stipulation and Settlement Agreement (the Agreement) related to retail rate matters. The Agreement was approved by the FPSC in April 2002. The Agreement is generally effective from May 2002 through December 2005; provided, however, that if PEF's base rate earnings fall below a 10% return on equity, PEF may petition the FPSC to amend its base rates.

The Agreement provides that PEF will reduce its retail revenues from the sale of electricity by an annual amount of $125 million. The Agreement also provides that PEF will operate under a Revenue Sharing Incentive Plan

(the Plan) through 2005, and thereafter until terminated by the FPSC, that establishes annual revenue caps and sharing thresholds. The Plan provides that retail base rate revenues between the sharing thresholds and the retail base rate revenue caps will be divided into two shares — a 1/3 share to be received by PEF's shareholders, and a 2/3 share to be refunded to PEF's retail customers; provided, however, that for the year 2002 only, the refund to customers was limited to 67.1% of the 2/3 customer share. The retail base rate revenue sharing threshold amounts for 2003 and 2002 were $1,333 million and $1,296 million, respectively, and will increase $37 million each year thereafter. The Plan also provides that all retail base rate revenues above the retail base rate revenue caps established for each year will be refunded to retail customers on an annual basis. For 2002, the refund to customers was limited to 67.1% of the retail base rate revenues that exceeded the 2002 cap. The retail base revenue cap for 2003 and 2002 was $1,393 million and $1,356 million, respectively, and will increase $37 million each year thereafter. Any amounts above the retail base revenue caps will be refunded 100% to customers. At December 31, 2003, $17 million has been accrued and will be refunded to customers by March 2004. Approximately $5 million was originally returned in March 2003 related to 2002 revenue sharing. However, in February 2003, the parties to the Agreement filed a motion seeking an order from the FPSC to enforce the Agreement. In this motion, the parties disputed PEF's calculation of retail revenue subject to refund and contended that the refund should be approximately $23 million. In July 2003, the FPSC ruled that PEF must provide an additional $18 million to its retail customers related to the 2002 revenue sharing calculation. PEF recorded this refund in the second quarter of 2003 as a charge against electric operating revenue and refunded this amount by October 2003.

The Agreement also provides that, beginning with the in-service date of PEF's Hines Unit 2 and continuing through December 2005, PEF will be allowed to recover through the fuel cost recovery clause a return on average investment and depreciation expense for Hines Unit 2, to the extent such costs do not exceed the Unit's cumulative fuel savings over the recovery period. Hines Unit 2 is a 516 MW combined-cycle unit that was placed in service in December 2003.

PEF will suspend accruals on its reserves for nuclear decommissioning and fossil dismantlement through December 2005. Additionally, for each calendar year during the term of the Agreement, PEF will record a $63 million depreciation expense reduction, and may, at its option, record up to an equal annual amount as an offsetting accelerated depreciation expense. In addition, PEF is authorized, at its discretion, to accelerate the amortization of certain regulatory assets over the term of the Agreement. In 2003, PEF recorded $16 million of accelerated amortization of a regulatory liability related to a settled tax matter. There was no accelerated depreciation or amortization expense recorded for the year ended December 31, 2002.

Under the terms of the Agreement, PEF agreed to continue the implementation of its four-year Commitment to Excellence Reliability Plan and expects to achieve a 20% improvement in its annual System Average Interruption Duration Index by no later than 2004. If this improvement level is not achieved for calendar years 2004 or 2005, PEF will provide a refund of $3 million for each year the level is not achieved to 10% of its total retail customers served by its worst performing distribution feeder lines.

The Agreement also provided that PEF was required to refund to customers $35 million of revenues PEF collected during the interim period since March 2001. This one-time retroactive revenue refund was recorded in the first quarter of 2002 and was returned to retail customers during 2002. Any additional refunds under the Agreement are recorded when they become probable.

8. GOODWILL AND OTHER INTANGIBLE ASSETS

Effective January 2002, the Company adopted SFAS No. 142. As required by SFAS No. 142, the results for the prior year periods have not been restated. A reconciliation of net income as if SFAS No. 142 had been adopted is presented below for the year ended December 31, 2001. The goodwill amortization used in the reconciliation includes $6 million related to NCNG, which is included in discontinued operations.

(in millions, except per share data)	Net income	Basic earnings per common share	Diluted earnings per common share
Reported	$542	$2.65	$2.64
Goodwill amortization	96	0.47	0.47
Adjusted	$638	$3.12	$3.11

The changes in the carrying amount of goodwill for the years ended December 31, 2002 and 2003, by reportable segment, are as follows:

(in millions)	PEC Electric	PEF	CCO	Other	Total
Balance as of January 1, 2002	$1,922	$1,733	$—	$35	$3,690
Acquisitions (Note 4D)	—	—	64	—	64
Divestitures	—	—	—	(2)	(2)
Discontinued operations (Note 3A)	—	—	—	(33)	(33)
Balance as of December 31, 2002	$1,922	$1,733	$64	$—	$3,719
Acquisitions (Note 4A)	—	—	—	7	7
Balance as of December 31, 2003	**$1,922**	**$1,733**	**$64**	**$7**	**$3,726**

The Company performed the annual goodwill impairment test for the CCO segment in the first quarter of 2003, and the annual goodwill impairment test for the PEC Electric and PEF segments in the second quarter of 2003, which indicated no impairment. The first annual impairment test for the Other segment will be performed in 2004, since the goodwill was acquired in 2003.

The gross carrying amount and accumulated amortization of the Company's intangible assets at December 31 are as follows:

	2003		2002	
(in millions)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Synthetic fuel intangibles	$140	$(64)	$140	$(45)
Power agreements acquired	221	(20)	33	(6)
Other	62	(12)	41	(8)
Total	$423	$(96)	$214	$(59)

All of the Company's intangibles are subject to amortization. Synthetic fuel intangibles represent intangibles for synthetic fuel technology. These intangibles are being amortized on a straight-line basis until the expiration of tax credits under Section 29 of the Internal Revenue Code (Section 29) in December 2007 (See Note 14). In May 2003, PVI acquired a long-term full-requirements power supply agreement at fixed prices for $188 million. The intangible related to this power agreement is being amortized based on the economic benefits of the contract (See Note 4C). As part of the acquisition of generating assets from LG&E Energy Corp. in February 2002, power agreements of $33 million were recorded and are amortized based on the economic benefits of the contracts through December 2004, which approximates straight-line (See Note 4D). Other intangibles are primarily acquired customer contracts and permits that are amortized over their respective lives. Of the increase in other intangible assets, $9 million relates to customer contracts acquired as part of the Westchester acquisition, which was identified as an intangible in the final purchase price allocation (See Note 4E).

Amortization expense recorded on intangible assets for the years ended December 31, 2003, 2002 and 2001, was, in millions, $37, $33 and $22, respectively. The estimated annual amortization expense for intangible assets for 2004 through 2008, in millions, is approximately $42, $35, $36, $36 and $17, respectively.

9. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

Effective January 1, 2002, the Company adopted SFAS No. 144, which provides guidance for the accounting and reporting of impairment or disposal of long-lived assets. The statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of." In 2003, 2002 and 2001, the Company recorded pre-tax long-lived asset and investment impairments and other charges of approximately $38 million, $414 million and $209 million, respectively.

A. Long-Lived Assets

Due to the reduction in coal production the Company evaluated Kentucky May Coal Mine's long-lived assets in 2003. Fair value was determined based on discounted cash flows. As a result of this review, the Company recorded asset impairments of $17 million on a pre-tax basis during the fourth quarter of 2003.

An estimated impairment of assets held for sale of $59 million is included in the 2002 amount, which relates to Railcar Ltd. (See Note 3B).

Due to the decline of the telecommunications industry and continued operating losses, the Company initiated an independent valuation study during 2002 to assess the recoverability of the long-lived assets of PTC and Caronet. Based on this assessment, the Company recorded asset impairments of $305 million on a pre-tax basis and other charges of $25 million on a pre-tax basis primarily related to inventory adjustments in the third quarter of 2002. This write-down constitutes a significant reduction in the book value of these long-lived assets.

The long-lived asset impairments include an impairment of property, plant and equipment, construction work in process and intangible assets. The impairment charge represents the difference between the fair value and carrying amount of these long-lived assets. The fair value of these assets was determined using a valuation study

heavily weighted on the discounted cash flow methodology, using market approaches as supporting information.

Due to historical losses at Strategic Resource Solutions Corp. (SRS) and the decline in the market value for technology companies, the Company evaluated the long-lived assets of SRS in 2001. Fair value was determined based on discounted cash flows. As a result of this review, the Company recorded asset impairments of $43 million and other charges of $2 million on a pre-tax basis during the fourth quarter of 2001.

B. Investments

The Company continually reviews its investments to determine whether a decline in fair value below the cost basis is other than temporary. In 2003, PEC's affordable housing investment (AHI) portfolio was reviewed and deemed to be impaired based on various factors including continued operating losses of the AHI portfolio and management performance issues arising at certain properties within the AHI portfolio. As a result, PEC recorded an impairment of $18 million on a pre-tax basis during the fourth quarter of 2003. PEC also recorded an impairment of $3 million for a cost investment.

In 2001, the Company obtained a valuation study to assess its investment in Interpath Communications, Inc. (Interpath) based on current valuations in the technology sector. As a result, the Company recorded an impairment for other-than-temporary declines in the fair value of its investment in Interpath. Investment impairments were also recorded related to certain investments of SRS. Investment write-downs totaled $164 million on a pre-tax basis for the year ended December 31, 2001. In May 2002, Interpath merged with a third party. As a result, the Company reviewed the Interpath investment for impairment and wrote off the remaining amount of its cost-basis investment in Interpath, recording a pre-tax impairment of $25 million in the third quarter of 2002. In the fourth quarter of 2002, the Company sold its remaining interest in Interpath for a nominal amount.

10. EQUITY

A. Common Stock

In November 2002, the Company issued 14.7 million shares of common stock for net cash proceeds of approximately $600 million, which were primarily used to retire commercial paper. In April 2002, the Company issued 2.5 million shares of common stock, valued at approximately $129 million, in conjunction with the purchase of Westchester (See Note 4E). In August 2001, the Company issued 12.6 million shares of common stock for net cash proceeds of $489 million, which were primarily used to retire commercial paper.

At December 31, 2003, the Company had approximately 53 million shares of common stock authorized by the Board of Directors that remained unissued and reserved, primarily to satisfy the requirements of the Company's stock plans. In 2002, the Board of Directors authorized meeting the requirements of the Progress Energy 401(k) Savings and Stock Ownership Plan and the Investor Plus Stock Purchase Plan with original issue shares. Prior to that authorization, the Company met the requirements of these stock plans with issued and outstanding shares held by the Trustee of the Progress Energy 401(k) Savings and Stock Ownership Plan (previously known as the Progress Energy, Inc. Stock Purchase-Savings Plan) or with open market purchases of common stock shares, as appropriate. During 2003 and 2002, respectively, the Company issued approximately 8 million and 2 million shares under these plans for net proceeds of approximately $309 million and $86 million. The Company continues to meet the requirements of the restricted stock plan with issued and outstanding shares.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2003, there were no significant restrictions on the use of retained earnings.

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

The Company sponsors the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) for which substantially all full-time, non-bargaining unit employees and certain part-time, non-bargaining unit employees within participating subsidiaries are eligible. Participating subsidiaries within the Company as of January 1, 2003, were PEC, PEF, PTC, Progress Fuels (Corporate) and Progress Energy Service Company. Effective December 19, 2003 (the PTC LLP/EPIK merger date), PTC no longer participates in the 401(k) plan. The 401(k), which has Company matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Company common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Company common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation

to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to Company matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. To the extent used to repay such loans, the dividends are deductible for income tax purposes. Also, beginning in 2002, the dividends paid on ESOP shares which are either paid directly to participants or used to purchase additional shares which are then allocated to participants are fully deductible for income tax purposes.

There were 4.0 million and 4.6 million ESOP suspense shares at December 31, 2003 and 2002, respectively, with a fair value of $183 million and $200 million, respectively. ESOP shares allocated to plan participants totaled 13.1 million and 13.6 million in December 31, 2003 and 2002, respectively. The Company's matching and incentive goal compensation cost under the 401(k) is determined based on matching percentages and incentive goal attainment as defined in the plan. Such compensation cost is allocated to participants' accounts in the form of Company common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. The Company currently meets common stock share needs with open market purchases, with shares released from the ESOP suspense account and with newly issued shares. Costs for incentive goal compensation are accrued during the fiscal year and typically paid in shares in the following year; while costs for the matching component are typically met with shares in the same year incurred. Matching and incentive cost which were met and will be met with shares released from the suspense account totaled approximately $20 million, $20 million and $18 million for the years ended December 31, 2003, 2002 and 2001, respectively. Total matching and incentive cost totaled approximately $35 million, $30 million and $29 million for the years ended December 31, 2003, 2002 and 2001, respectively, including 2001 amounts incurred under the previous Florida Progress Corporation (Florida Progress) Plan. The Company has a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from the Company in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

STOCK OPTION AGREEMENTS

Pursuant to the Company's 1997 Equity Incentive Plan and 2002 Equity Incentive Plan, amended and restated as of July 10, 2002, the Company may grant options to purchase shares of common stock to directors, officers and eligible employees for up to 5 million and 15 million shares, respectively. Generally, options granted to employees vest one-third per year with 100% vesting at the end of year three while options granted to directors vest 100% at the end of one year. The options expire ten years from the date of grant. All option grants have an exercise price equal to the fair market value of the Company's common stock on the grant date. The Company measures compensation expense for stock options as the difference between the market price of its common stock and the exercise price of the option at the grant date. The exercise price at which options are granted by the Company equals the market price at grant date and accordingly, no compensation expense has been recognized for any options granted during 2003, 2002 and 2001.

The pro forma information presented in Note 1 regarding net income and earnings per share is required by SFAS No. 148. Under this statement, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The pro forma amounts presented in Note 1 have been determined as if the Company had accounted for its employee stock options under SFAS No. 123. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted-average assumptions:

	2003	2002	2001
Risk-free interest rate	4.25%	4.14%	4.83%
Dividend yield	4.75%	5.20%	5.21%
Volatility factor	22.28%	24.98%	26.47%
Weighted-average expected life of the options (in years)	10	10	10

The option valuation model requires the input of highly subjective assumptions, primarily stock price volatility, changes in which can materially affect the fair value estimate.

The options outstanding at December 31, 2003, 2002 and 2001, had a weighted-average remaining contractual life of 8.70, 9.32 and 9.75 years, respectively, and had exercise prices that ranged from $40.41 to $51.85. At December 31, 2003, 92 thousand options have been exercised, while no options have expired. The tabular information for the option activity is as follows:

	2003		2002		2001	
(options quantities in millions)	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	5.2	$42.84	2.3	$43.49	—	
Granted	3.0	$44.70	2.9	$42.34	2.4	$43.49
Forfeited	(0.1)	$43.64	—	$43.71	(0.1)	$43.49
Canceled	(0.1)	$43.62	—	—	—	—
Exercised	—	$43.00	—	—	—	—
Options outstanding, December 31	8.0	$43.54	5.2	$42.84	2.3	$43.49
Options exercisable, December 31 with a remaining contractual life of 8.75 years	2.4	$43.09	0.8	$43.49	—	—
Weighted-average grant date fair value of options granted during the year		$7.16		$6.83		$8.05

OTHER STOCK-BASED COMPENSATION PLANS

The Company has additional compensation plans for officers and key employees of the Company that are stock-based in whole or in part. The two primary programs are the Performance Share Sub-Plan (PSSP) and the Restricted Stock Awards program (RSA), both of which were established pursuant to the Company's 1997 Equity Incentive Plan and were continued under the Company's 2002 Equity Incentive Plan, as amended and restated as of July 10, 2002.

Under the terms of the PSSP, officers and key employees of the Company are granted performance shares that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of the Company's common stock, and dividend equivalents are accrued on, and reinvested in, the performance shares. The PSSP has two equally weighted performance measures, both of which are based on the Company's results as compared to a peer group of utilities. Compensation expense is recognized over the vesting period based on the expected ultimate cash payout. Compensation expense is reduced by any forfeitures.

The RSA program allows the Company to grant shares of restricted common stock to officers and key employees of the Company. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. The weighted-average price of restricted shares at the grant date was $39.53, $44.27 and $41.86 in 2003, 2002 and 2001, respectively. Compensation expense is reduced by any forfeitures. Restricted shares are not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. Changes in restricted stock shares outstanding were:

	2003	2002	2001
Beginning balance	950,180	674,511	653,344
Granted	180,200	365,920	113,651
Vested	(151,677)	(75,200)	(70,762)
Forfeited	(33,820)	(15,051)	(21,722)
Ending balance	944,883	950,180	674,511

The total amount expensed for other stock-based compensation plans was $27 million, $17 million and $14 million in 2003, 2002 and 2001, respectively.

C. Earnings Per Common Share

Basic earnings per common share is based on the weighted-average number of common shares outstanding. Diluted earnings per share includes the effect of the non-vested portion of restricted stock awards and the effect of stock options outstanding.

A reconciliation of the weighted-average number of common shares outstanding for basic and dilutive purposes is as follows:

(in millions)	2003	2002	2001
Weighted-average common shares — basic	237.2	217.2	204.7
Restricted stock awards	1.0	.8	.6
Stock options	—	.2	—
Weighted-average shares — fully diluted	238.2	218.2	205.3

There are no adjustments to net income or to income from continuing operations between the calculations of basic and fully diluted earnings per common share. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. The weighted-average of these shares totaled 4.1 million, 4.8 million and 5.4 million for the years ended December 31, 2003, 2002 and 2001, respectively. There were 5.3 million and 92 thousand stock options outstanding at December 31, 2003 and 2002, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive.

D. Accumulated Other Comprehensive Loss

Components of accumulated other comprehensive loss are as follows:

(in millions)	2003	2002
Loss on cash flow hedges	$(35)	$(42)
Minimum pension liability adjustments	(15)	(192)
Foreign currency translation and other	—	(4)
Total accumulated other comprehensive loss	$(50)	$(238)

11. PREFERRED STOCK OF SUBSIDIARIES — NOT SUBJECT TO MANDATORY REDEMPTION

All of the Company's preferred stock was issued by its subsidiaries and was not subject to mandatory redemption. Preferred stock outstanding at December 31, 2003 and 2002, consisted of the following:

(in millions, except share data and par value)	2003	2002
Progress Energy Carolinas, Inc.		
Authorized — 300,000 shares, cumulative, $100 par value Preferred Stock; 20,000,000 shares, cumulative, $100 par value Serial Preferred Stock		
$5.00 Preferred — 236,997 shares outstanding (redemption price $110.00)	$24	$24
$4.20 Serial Preferred — 100,000 shares outstanding (redemption price $102.00)	10	10
$5.44 Serial Preferred — 249,850 shares outstanding (redemption price $101.00)	25	25
	$59	$59
Progress Energy Florida, Inc.		
Authorized — 4,000,000 shares, cumulative, $100 par value Preferred Stock; 5,000,000 shares, cumulative, no par value Preferred Stock; 1,000,000 shares, $100 par value Preference Stock		
$100 par value Preferred Stock:		
4.00% — 39,980 shares outstanding (redemption price $104.25)	$4	$4
4.40% — 75,000 shares outstanding (redemption price $102.00)	8	8
4.58% — 99,990 shares outstanding (redemption price $101.00)	10	10
4.60% — 39,997 shares outstanding (redemption price $103.25)	4	4
4.75% — 80,000 shares outstanding (redemption price $102.00)	8	8
	$34	$34
Total Preferred Stock of Subsidiaries	$93	$93

12. DEBT AND CREDIT FACILITIES

A. Debt and Credit

At December 31, the Company's long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2003):

(in millions)		2003	2002
Progress Energy, Inc.			
Senior unsecured notes, maturing 2004-2031	6.86%	$4,800	$4,800
Unamortized fair value hedge gain, net		19	34
Unamortized premium and discount, net		(27)	(31)
		4,792	4,803
Progress Energy Carolinas, Inc.			
First mortgage bonds, maturing 2004-2033	6.42%	1,900	1,550
Pollution control obligations, maturing 2010-2024	1.69%	708	708
Unsecured notes, maturing 2012	6.50%	500	500
Medium-term notes, maturing 2008	6.65%	300	300
Miscellaneous notes		—	6
Unamortized premium and discount, net		(22)	(16)
		3,386	3,048
Progress Energy Florida, Inc.			
First mortgage bonds, maturing 2004-2033	5.60%	1,330	810
Pollution control obligations, maturing 2018-2027	1.04%	241	241
Medium-term notes, maturing 2004-2028	6.75%	379	417
Unamortized premium and discount, net		(3)	(7)
		1,947	1,461
Florida Progress Funding Corporation (See Note 12F)			
Debt to affiliated trust, maturing 2039	7.10%	309	—
Mandatorily redeemable preferred securities, maturing 2039		—	300
Unamortized premium and discount, net		(39)	(39)
		270	261
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2004-2008	6.78%	165	223
Miscellaneous notes		1	1
		166	224
Progress Genco Ventures, LLC			
Variable rate project financing, maturing 2007	3.04%	241	225
Current portion of long-term debt		(868)	(275)
Total long-term debt		$9,934	$9,747

At December 31, 2003 and 2002, the Company had $4 million and $695 million, respectively, of outstanding commercial paper and other short-term debt classified as short-term obligations. The weighted-average interest rates of such short-term obligations at December 31, 2003 and 2002, were 2.25% and 1.67%, respectively.

At December 31, 2003, the Company had committed lines of credit which are used to support its commercial paper borrowings and had no outstanding loans. The Company is required to pay minimal annual commitment fees to maintain its credit facilities. The following table summarizes the Company's credit facilities:

(in millions) Company	Description	Total
Progress Energy, Inc.	364-Day (expiring 11/10/04)	$250
Progress Energy, Inc.	3-Year (expiring 11/13/04)	450
Progress Energy Carolinas, Inc.	364-Day (expiring 7/29/04)	165
Progress Energy Carolinas, Inc.	3-Year (expiring 7/31/05)	285
Progress Energy Florida, Inc.	364-Day (expiring 3/31/04)	200
Progress Energy Florida, Inc.	3-Year (expiring 4/1/06)	200
Total credit facilities		$1,550

Progress Energy and PEF each have an uncommitted bank bid facility authorizing them to borrow and reborrow, and have loans outstanding at any time, up to $300 million and $100 million, respectively. These bank bid facilities were not drawn at December 31, 2003.

The combined aggregate maturities of long-term debt for 2004 through 2008 are approximately $868 million, $348 million, $908 million, $915 million and $827 million, respectively.

B. Covenants and Default Provisions

FINANCIAL COVENANTS

Progress Energy's, PEC's and PEF's credit lines and the bank facility of Progress Genco Ventures, LLC (Genco), a PVI subsidiary, contain various terms and conditions that could affect the Company's ability to borrow under these facilities. These include maximum debt to total capital ratios, interest coverage tests, material adverse change clauses and cross-default provisions.

All of the credit facilities and the Genco's bank facility include a defined maximum total debt to total capital ratio. At December 31, 2003, the maximum and calculated ratios for these four companies, pursuant to the terms of the agreements, are as follows:

Company	Maximum Ratio	Actual Ratio[a]
Progress Energy, Inc.	68%	61.5%
Progress Energy Carolinas, Inc.	65%	51.4%
Progress Energy Florida, Inc.	65%	51.5%
Progress Genco Ventures, LLC	40%	24.6%

[a] *Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees which are not recorded on the Consolidated Balance Sheets.*

Progress Energy's 364-day credit facility and both PEF's 364-day and 3-year credit facilities have a financial covenant for interest coverage. The covenants require Progress Energy's and PEF's Earnings before interest, taxes, and depreciation and amortization to interest expense ratio to be at least 2.5 to 1 and 3 to 1, respectively. For the year ended December 31, 2003, the ratios were 3.74 to 1 and 9.22 to 1 for the Company and PEF, respectively. Genco's bank facility requires a minimum 1.25 to 1 debt service coverage ratio. For the year ended December 31, 2003, Genco's debt service coverage was 6.35 to 1.

MATERIAL ADVERSE CHANGE CLAUSE

The credit facilities of Progress Energy, PEC, PEF and Genco include a provision under which lenders could refuse to advance funds in the event of a material adverse change in the borrower's financial condition.

CROSS-DEFAULT PROVISIONS

Progress Energy's, PEC's and PEF's credit lines include cross-default provisions for defaults of indebtedness in excess of $10 million. Progress Energy's cross-default provisions only apply to defaults of indebtedness by Progress Energy and its significant subsidiaries (i.e., PEC, FPC, PEF, PVI, Progress Fuels and Progress Capital Holdings, Inc. [PCH]). PEC's and PEF's cross-default provisions only apply to defaults of indebtedness by PEC and PEF and their subsidiaries, respectively, not other affiliates of PEC or PEF. The Genco credit facility includes a similar provision for defaults by Progress Energy or PVI.

Additionally, certain of Progress Energy's long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of $25 million; these provisions only apply to other obligations of Progress Energy, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $4,800 million in long-term debt. Certain agreements underlying the Company's indebtedness also limit its ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither Progress Energy's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends. Certain documents restrict the payment of dividends by Progress Energy's subsidiaries as outlined below.

PEC's mortgage indenture provides that, as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million,

less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2003, none of PEC's retained earnings were restricted.

In addition, PEC's Articles of Incorporation provide that cash dividends on common stock shall be limited to 75% of net income available for dividends if common stock equity falls below 25% of total capitalization, and to 50% if common stock equity falls below 20%. At December 31, 2003, PEC's common stock equity was approximately 50.7% of total capitalization.

PEF's mortgage indenture provides that it will not pay any cash dividends upon its common stock, or make any other distribution to the stockholders, except a payment or distribution out of net income of PEF subsequent to December 31, 1943. At December 31, 2003, none of PEF's retained earnings were restricted.

In addition, PEF's Articles of Incorporation provide that no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceed (a) all credits to retained earnings since April 30, 1944, plus (b) all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus.

PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75% of net income available for dividends if common stock equity falls below 25% of total capitalization, and to 50% if common stock equity falls below 20%. On December 31, 2003, PEF's common stock equity was approximately 52.5% of total capitalization.

Genco is required to hedge 75% of the amount outstanding under its bank facility through September 2005 and 50% thereafter, pursuant to the term of the agreement for expansion of its nonregulated generation portfolio. At December 31, 2003, Genco held interest rate cash flow hedges with a notional amount of $195 million and a total fair value of $11 million liability position related to this covenant. See additional discussion of interest rate cash flow hedges in Note 17.

C. Secured Obligations

PEC's and PEF's first mortgage bonds are secured by their respective mortgage indentures. Each mortgage constitutes a first lien on substantially all of the fixed properties of the respective company, subject to certain permitted encumbrances and exceptions. Each mortgage also constitutes a lien on subsequently acquired property. At December 31, 2003, PEC and PEF had a total of approximately $4,179 million of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

Genco obtained a bank facility to be used exclusively for expansion of its nonregulated generation portfolio. Borrowings under this facility are secured by the assets in the generation portfolio. The facility is for up to $260 million, of which $241 million had been drawn at December 31, 2003. Borrowings under the facility are restricted for the operations, construction, repayments and other related charges of the credit facility for the development projects. Cash held and restricted to operations was $24 million and $21 million at December 31, 2003 and 2002, respectively, and is included in other current assets. Cash held and restricted for long-term purposes was $9 million and $37 million at December 31, 2003 and 2002, respectively, and is included in other assets and deferred debits on the Consolidated Balance Sheets.

D. Guarantees of Subsidiary Debt

FPC has guaranteed the outstanding debt obligations for PCH, a wholly-owned subsidiary of Florida Progress. At December 31, 2003 and 2002, PCH had $165 million and $223 million, respectively; in medium-term notes outstanding which are recorded on the Company's accompanying Consolidated Balance Sheets.

E. Hedging Activities

Progress Energy uses interest rate derivatives to adjust the fixed and variable rate components of its debt portfolio and to hedge cash flow risk related to commercial paper and to fixed rate debt to be issued in the future. See discussion of risk management activities and derivative transactions at Note 17.

F. FPC-Obligated Mandatorily Redeemable Preferred Securities of an Unconsolidated Subsidiary Holding Solely FPC Guaranteed Notes

In April 1999, FPC Capital I (the Trust), an indirect wholly-owned subsidiary of FPC, issued 12 million shares of $25 par cumulative FPC-obligated mandatorily redeemable preferred securities (Preferred Securities) due 2039, with an aggregate liquidation value of $300 million and an annual distribution rate of 7.10%. Prior to the adoption of FIN No. 46, the Company consolidated the Trust, which holds the Preferred Securities. The Trust is a special-purpose entity, and therefore the Company applied FIN

No. 46 to the Trust at December 31, 2003 (See Note 2). The adoption of FIN No. 46 required the Company to deconsolidate the Trust at December 31, 2003.

The existence of the Trust is for the sole purpose of issuing the Preferred Securities and the common securities and using the proceeds thereof to purchase from Florida Progress Funding Corporation (Funding Corp.) its 7.10% Junior Subordinated Deferrable Interest Notes (subordinated notes) due 2039, for a principal amount of $309 million. The subordinated notes and the Notes Guarantee (as discussed below) are the sole assets of the Trust. Funding Corp.'s proceeds from the sale of the subordinated notes were advanced to Progress Capital and used for general corporate purposes including the repayment of a portion of certain outstanding short-term bank loans and commercial paper.

FPC has fully and unconditionally guaranteed the obligations of Funding Corp. under the subordinated notes (the Notes Guarantee). In addition, FPC has guaranteed the payment of all distributions related to the $300 million Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by FPC of the Trust's obligations under the Preferred Securities.

The subordinated notes may be redeemed at the option of Funding Corp. beginning in 2004 at par value plus accrued interest through the redemption date. The proceeds of any redemption of the subordinated notes will be used by the Trust to redeem proportional amounts of the Preferred Securities and common securities in accordance with their terms. Upon liquidation or dissolution of Funding Corp., holders of the Preferred Securities would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment.

Prior to December 2003, these Preferred Securities were classified as long-term debt on the Company's Consolidated Balance Sheets. After deconsolidation of the Trust at December 31, 2003, FPC's subordinated notes payable to the Trust are classified as affiliate long-term debt on the Company's December 31, 2003, Consolidated Balance Sheet.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts of cash and cash equivalents and short-term obligations approximate fair value due to the short maturities of these instruments. At December 31, 2003 and 2002, investments in company-owned life insurance and other benefit plan assets, with carrying amounts of approximately $162 million and $150 million, respectively, are included in miscellaneous other property and investments and approximate fair value due to the short maturity of the instruments. Other instruments are presented at fair value in accordance with GAAP. The carrying amount of the Company's long-term debt, including current maturities, was $10,802 million and $10,022 million at December 31, 2003 and 2002, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $11,917 million and $10,974 million at December 31, 2003 and 2002, respectively.

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 5D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments.

14. INCOME TAXES

Deferred income taxes are provided for temporary differences between book and tax bases of assets and liabilities. Investment tax credits related to regulated operations are amortized over the service life of the related property. To the extent that the establishment of deferred income taxes under SFAS No. 109, "Accounting for Income Taxes" is different from the recovery of taxes by PEC and PEF through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the utilities pursuant to rate orders.

Accumulated deferred income tax (assets) liabilities at December 31 are:

(in millions)	2003	2002
Accumulated depreciation and property cost differences	$1,524	$1,624
Deferred costs, net	(49)	(73)
Federal income tax credit carry forward	(682)	(472)
Minimum pension liability adjustment	(9)	(117)
Miscellaneous other temporary differences, net	(153)	(111)
Valuation allowance	42	47
Net accumulated deferred income tax liability	$673	$898

Total deferred income tax liabilities were $2,427 million and $2,430 million at December 31, 2003 and 2002, respectively. Total deferred income tax assets were $1,754 million and $1,532 million at December 31, 2003 and 2002, respectively. At December 31, 2003 and 2002, the Company had net noncurrent deferred tax liabilities of $737 million and $858 million. At December 31, 2003, the Company had a net current deferred tax asset of $64 million, which is included on the Consolidated Balance Sheets under the caption prepayments and other current assets. At December 31, 2002, the Company had a net current deferred tax liability of $40 million, which is included on the Consolidated Balance Sheets under the caption other current liabilities.

The federal income tax credit carry forward at December 31, 2003, consists of $659 million of alternative minimum tax credit with an indefinite carry forward period and $23 million of general business credit with a carry-forward period that will begin to expire in 2020.

The Company established additional valuation allowances of $5 million, $12 million and $24 million during 2003, 2002 and 2001, respectively, due to the uncertainty of realizing certain future state tax benefits. The overall decrease in the 2003 valuation allowance balance is largely due to the Company's sale of its wholly-owned subsidiary Caronet. The Company believes it is more likely than not that the results of future operations will generate sufficient taxable income to allow for the utilization of the remaining deferred tax assets.

Reconciliations of the Company's effective income tax rate to the statutory federal income tax rate are:

	2003	2002	2001
Effective income tax rate	(15.5)%	(40.0)%	(40.0)%
State income taxes, net of federal benefit	(3.3)	(8.2)	(7.7)
AFUDC amortization	(2.0)	(5.2)	(5.0)
Federal tax credits	50.3	78.0	94.5
Goodwill amortization and write-offs	—	—	(11.4)
Investment tax credit amortization	2.3	4.7	5.9
ESOP dividend deduction	2.1	3.8	1.9
Interpath investment impairment	—	—	(2.1)
Other differences, net	1.1	1.9	(1.1)
Statutory federal income tax rate	35.0%	35.0%	35.0%

Income tax expense (benefit) applicable to continuing operations is comprised of:

(in millions)	2003	2002	2001
Current			
Federal	$129	$195	$184
State	54	67	52
Deferred			
Federal	(255)	(379)	(357)
State	(21)	(23)	(10)
Investment tax credit	(16)	(18)	(23)
Total income tax expense (benefit)	$(109)	$(158)	$(154)

The Company, through its subsidiaries, is a majority owner in five entities and a minority owner in one entity that owns facilities that produce synthetic fuel as defined under the Internal Revenue Code (Code). The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 if certain requirements are satisfied, including a requirement that the synthetic fuel differs significantly in chemical composition from the coal used to produce such synthetic fuel and that the fuel was produced from a facility that was placed in service before July 1, 1998. Total Section 29 credits generated to date (including FPC prior to its acquisition by the Company) are approximately $1,243 million. All entities have received private letter rulings (PLRs) from the Internal Revenue Service (IRS) with respect to their synthetic fuel operations. The PLRs do not limit the production on which synthetic fuel credits may be claimed. Should the tax credits be denied on future audits, and the Company fails to prevail through the IRS or legal process, there could be a significant tax liability owed for previously taken Section 29 credits, with a significant impact on earnings and cash flows.

One of the Company's synthetic fuel entities, Colona Synfuel Limited Partnership, L.L.L.P. (Colona), was audited by the IRS. The audit of Colona was expected. The Company is audited regularly in the normal course of business as are most similarly situated companies. The Company (including FPC prior to its acquisition by the Company) has been allocated approximately $317 million in tax credits to date from this synthetic fuel entity.

In September 2002, all of Progress Energy's majority-owned synthetic fuel entities, including Colona, were accepted into the IRS's Pre-Filing Agreement (PFA) program. The PFA program allows taxpayers to voluntarily accelerate the IRS exam process in order to seek resolution of specific issues. Either the Company or the IRS can withdraw from the program at any time, and

issues not resolved through the program may proceed to the next level of the IRS exam process. While the ultimate outcome is uncertain, the Company believes that participation in the PFA program will likely shorten the tax exam process.

In June 2003, the Company was informed that IRS field auditors had raised questions regarding the chemical change associated with coal-based synthetic fuel manufactured at its Colona facility and the testing process by which the chemical change is verified. (The questions arose in connection with the Company's participation in the PFA program.) The chemical change and the associated testing process were described as part of the PLR request for Colona. Based on that application, the IRS ruled in Colona's PLR that the synthetic fuel produced at Colona undergoes a significant chemical change and thus qualifies for tax credits under Section 29.

In October 2003, the National Office of the IRS informed the Company that it had rejected the IRS field auditors' challenges regarding whether the synthetic fuel produced at the Company's Colona facility was the result of a significant chemical change. The National Office had concluded that the experts engaged by Colona, who test the synthetic fuel for chemical change, use reasonable scientific methods to reach their conclusions. Accordingly, the National Office will not take any adverse action on the PLR that has been issued for the Colona facility.

Although this ruling applies only to the Colona facility, the Company believes that the National Office's reasoning would be equally applicable to the other Progress Energy facilities. The Company applies essentially the same chemical process and uses the same independent laboratories to confirm chemical change in the synthetic fuel manufactured at each of its other facilities.

In February 2004, subsidiaries of the Company finalized execution of the Colona Closing Agreement with the Internal Revenue Service concerning their Colona synthetic fuel facilities. The Colona Closing Agreement provided that the Colona facilities were placed in service before July 1, 1998, which is one of the qualification requirements for tax credits under Section 29. The Colona Closing Agreement further provides that the fuel produced by the Colona facilities in 2001 is a "qualified fuel" for purposes of the Section 29 tax credits. This action concludes the IRS PFA program with respect to Colona.

Although the execution of the Colona Closing Agreement is a significant event, the audits of the Company's facilities are not yet completed and the PFA process continues with respect to the four synthetic fuel facilities owned by other affiliates of Progress Energy and FPC. Currently, the focus of that process is to determine that the facilities were placed in service before July 1, 1998. In management's opinion, Progress Energy is complying with all the necessary requirements to be allowed such credits under Section 29, although it cannot provide certainty that it will prevail if challenged by the IRS on credits taken. Accordingly, the Company has no current plans to alter its synthetic fuel production schedule as a result of these matters.

In October 2003, the United States Senate Permanent Subcommittee on Investigations began a general investigation concerning synthetic fuel tax credits claimed under Section 29. The investigation is examining the utilization of the credits, the nature of the technologies and fuels created, the use of the synthetic fuel and other aspects of Section 29 and is not specific to the Company's synthetic fuel operations. Progress Energy is providing information in connection with this investigation. The Company cannot predict the outcome of this matter.

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of FPC during 2000, the Company issued 98.6 million contingent value obligations (CVOs). Each CVO represents the right to receive contingent payments based on the performance of four synthetic fuel facilities purchased by subsidiaries of FPC in October 1999. The payments, if any, would be based on the net after-tax cash flows the facilities generate. The CVO liability is adjusted to reflect market price fluctuations. The liability, included in other liabilities and deferred credits, at December 31, 2003 and 2002, was $23 million and $14 million, respectively.

16. BENEFIT PLANS

A. Postretirement Benefits

The Company and some of its subsidiaries have a noncontributory defined benefit retirement (pension) plan for substantially all full-time employees. The Company also has supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, the Company and some of its subsidiaries provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. The Company uses a measurement date of December 31 for its pension and OPEB plans.

The components of net periodic benefit cost for the years ended December 31 are:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2003	2002	2001	2003	2002	2001
Service cost	$52	$45	$31	$15	$13	$13
Interest cost	108	106	96	33	32	28
Expected return on plan assets	(144)	(161)	(169)	(4)	(5)	(5)
Amortization of actuarial (gain) loss	25	2	(5)	5	1	—
Other amortization, net	—	—	(1)	4	4	5
Net periodic cost/(benefit)	$41	$(8)	$(48)	$53	$45	$41
Additional cost/(benefit) recognition (Note 16B)	(18)	(7)	(16)	2	2	4
Net periodic cost/(benefit) recognized	$23	$(15)	$(64)	$55	$47	$45

In addition to the net periodic cost and benefit reflected above, in 2003 the Company recorded curtailment and settlement effects related to the disposition of NCNG, which are reflected in income/(loss) from discontinued operations in the Consolidated Statements of Income. These effects included a pension-related loss of $13 million and an OPEB-related gain of $1 million.

Prior service costs and benefits are amortized on a straight-line basis over the average remaining service period of active participants. Actuarial gains and losses in excess of 10% of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

To determine the market-related value of assets, the Company uses a 5-year averaging method for a portion of its pension assets and fair value for the remaining portion. The Company has historically used the 5-year averaging method. When the Company acquired Florida Progress in 2000, it retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets.

Reconciliations of the changes in the plans' benefit obligations and the plans' funded status are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2003	2002	2003	2002
Projected benefit obligation at January 1	$1,694	$1,391	$514	$401
Service cost	52	45	15	13
Interest cost	108	106	33	32
Disposition of NCNG	(39)	—	(13)	—
Benefit payments	(94)	(91)	(24)	(24)
Actuarial loss (gain)	(66)	243	30	92
Obligation at December 31	1,655	1,694	555	514
Fair value of plan assets at December 31	1,631	1,364	65	52
Funded status	(24)	(330)	(490)	(462)
Unrecognized transition obligation	—	1	25	30
Unrecognized prior service cost	4	5	7	7
Unrecognized net actuarial (gain) loss	388	742	123	108
Minimum pension liability adjustment	(23)	(497)	—	—
Prepaid (accrued) cost at December 31, net (Note 16B)	$345	$(79)	$(335)	$(317)

The net prepaid pension cost of $345 million at December 31, 2003, is recognized in the Consolidated Balance Sheets as prepaid pension cost of $462 million and accrued benefit cost of $117 million, which is included in other liabilities and deferred credits. The net accrued pension cost of $79 million at December 31, 2002, is recognized in the Consolidated Balance Sheets as prepaid pension cost of $60 million and accrued benefit cost of $139 million, of which $130 million is included in other liabilities and deferred credits and $9 million is included in liabilities of discontinued operations. The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $125 million and $1.51 billion at December 31, 2003 and 2002, respectively. Those plans had accumulated benefit obligations totaling $117 million and $1.35 billion December 31, 2003 and 2002, respectively, no plan assets at December 31, 2003, and plan assets totaling $1.22 billion at December 31, 2002. The total accumulated benefit obligation for pension plans was $1.61 billion and $1.49 billion at December 31, 2003 and 2002, respectively. The accrued OPEB cost is included in other liabilities and deferred credits in the accompanying Consolidated Balance Sheets.

A minimum pension liability adjustment of $23 million, related to the supplementary defined benefit pension plans, was recorded at December 31, 2003. This adjustment is offset by a corresponding pre-tax amount in accumulated other comprehensive loss, a component of common stock equity. Due to a combination of decreases in the fair value of plan assets and a decrease in the discount rate used to measure the pension obligation, a minimum pension liability adjustment of $497 million was recorded at December 31, 2002. This adjustment resulted in a charge of $5 million to intangible assets, included in other assets and deferred debits in the accompanying Consolidated Balance Sheets, a $178 million charge to a pension-related regulatory liability (See Note 16B) and a pre-tax charge of $313 million to accumulated other comprehensive loss, a component of common stock equity.

Reconciliations of the fair value of plan assets are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2003	2002	2003	2002
Fair value of plan assets January 1	$1,364	$1,678	$52	$56
Actual return on plan assets	391	(228)	12	(5)
Disposition of NCNG	(35)	—	—	—
Benefit payments	(94)	(91)	(24)	(24)
Employer contributions	5	5	25	25
Fair value of plan assets at December 31	$1,631	$1,364	$65	$52

In the table above, substantially all employer contributions represent benefit payments made directly from Company assets. The remaining benefits payments were made directly from plan assets. The OPEB benefit payments represent the net Company cost after participant contributions. Participant contributions represent approximately 20% of gross benefit payments.

The asset allocation for the Company's plans at the end of 2003 and 2002 and the target allocation for the plans, by asset category, are as follows:

	Pension Benefits			Other Postretirement Benefits		
	Target Allocations	Percentage of Plan Assets at Year End		Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2004	2003	2002	2004	2003	2002
Equity						
Domestic	50%	49%	47%	35%	35%	32%
International	15%	22%	20%	10%	16%	14%
Debt						
Domestic	15%	11%	15%	45%	37%	41%
International	10%	11%	10%	5%	7%	7%
Other	10%	7%	8%	5%	5%	6%
Total	100%	100%	100%	100%	100%	100%

The Company sets target allocations among asset classes to provide broad diversification to protect against large investment losses and excessive volatility, while recognizing the importance of offsetting the impacts of benefit cost escalation. In addition, the Company employs external investment managers who have complementary investment philosophies and approaches. Tactical shifts (plus or minus 5%) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes.

In 2004, the Company expects to make $24 million of required contributions directly to pension plan assets and $1 million of discretionary contributions directly to the OPEB plan assets. The expected benefit payments for the pension benefit plan for 2004 through 2008 and in total for 2009-2013, in millions, are approximately $93, $96, $99, $104, $108 and $608, respectively. The expected benefit payments for the OPEB plan for 2004 through 2008 and in total for 2009-2013, in millions, are approximately $22, $24, $26, $28, $30 and $180, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from Company assets. The benefit payment amounts reflect the net cost to the Company after any participant contributions.

The following weighted-average actuarial assumptions were used in the calculation of the year-end obligation:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2003	2002	2003	2002
Discount rate	6.30%	6.60%	6.30%	6.60%
Rate of increase in future compensation				
Bargaining	3.50%	3.50%	—	—
Non-bargaining	—	4.00%	—	—
Supplementary plans	5.00%	4.00%		
Initial medical cost trend rate for pre-Medicare benefits	—	—	7.25%	7.50%
Initial medical cost trend rate for post-Medicare benefits	—	—	7.25%	7.50%
Ultimate medical cost trend rate	—	—	5.25%	5.25%
Year ultimate medical cost trend rate is achieved	—	—	2009	2009

The Company's primary defined benefit retirement plan for non-bargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4. Therefore, effective December 31, 2003, the Company began to use the traditional unit credit method for purposes of measuring the benefit obligation of this plan and will use that method to measure future benefit costs. Under the traditional unit credit method, no assumptions are included about future changes in compensation and the accumulated benefit obligation and projected benefit obligation are the same.

The following weighted-average actuarial assumptions were used in the calculation of the net periodic cost:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2003	2002	2001	2003	2002	2001
Discount rate	6.60%	7.50%	7.50%	6.60%	7.50%	7.50%
Rate of increase in future compensation						
Bargaining	3.50%	3.50%	3.50%	—	—	—
Non-bargaining and supplementary	4.00%	4.00%	4.00%	—	—	—
Expected long-term rate of return on plan assets	9.25%	9.25%	9.25%	8.45%	8.20%	8.70%
Initial medical cost trend rate for pre-Medicare benefits	—	—	—	7.50%	7.50%	7.2%-7.5%
Initial medical cost trend rate for post-Medicare benefits	—	—	—	7.50%	7.50%	6.2%-7.5%
Ultimate medical cost trend rate	—	—	—	5.25%	5.00%	5.0%-5.3%
Year ultimate medical cost trend rate is achieved	—	—	—	2009	2008	2005-2009

The expected long-term rates of return on plan assets were determined by considering long-term historical returns for the plans and long-term projected returns based on the plans' target asset allocation. For all pension plan assets and a substantial portion of OPEB plans assets, those benchmarks support an expected long-term rate of return between 9.5% and 10.0%. The Company has chosen to use an expected long-term rate of 9.25% due to the uncertainties of future returns.

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. Assuming a 1% increase in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2003 would increase by $3 million, and the OPEB obligation at December 31, 2003, would increase by $38 million. Assuming a 1% decrease in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2003 would decrease by $2 million and the OPEB obligation at December 31, 2003, would decrease by $33 million.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. In accordance with guidance issued by the FASB in FASB Staff Position FAS 106-1, the Company has elected to defer accounting for the effects of the Act due to uncertainties regarding the effects of the implementation of the Act and the accounting for certain provisions of the Act. Therefore, OPEB information presented above and in the financial statements does not reflect the effects of the Act. When specific authoritative accounting guidance is issued, it could require plan sponsors to change previously reported information. The Company is in the early stages of reviewing the Act and determining its potential effects on the Company.

B. FPC Acquisition

During 2000, the Company completed the acquisition of FPC. FPC's pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of FPC's non-bargaining unit benefit plans were merged with those of the Company effective January 1, 2002.

PEF continues to recover qualified plan pension costs and OPEB costs in rates as if the acquisition had not occurred. Accordingly, a portion of the accrued OPEB cost reflected in the table above has a corresponding regulatory asset at December 31, 2003 and 2002 (See Note 7A). In addition, a portion of the prepaid pension cost reflected in the table above has a corresponding regulatory liability (See Note 7A). Pursuant to its rate treatment, PEF recognized additional periodic pension credits and additional periodic OPEB costs, as indicated in the net periodic cost information above.

17. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

Under its risk management policy, the Company may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk if the counterparty fails to perform under the contract. The Company minimizes such risk by performing credit reviews using, among other things, publicly available credit ratings of such counterparties. Potential nonperformance by counterparties is not expected to have a material effect on the consolidated financial position or consolidated results of operations of the Company.

A. Commodity Contracts — General

Most of the Company's commodity contracts are not derivatives pursuant to SFAS No. 133 or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

During 2003 the FASB reconsidered an interpretation of SFAS No. 133 related to the pricing of contracts that include broad market indices (e.g., CPI). In particular, that guidance discussed whether the pricing in a contract that contains broad market indices could qualify as a normal purchase or sale (the normal purchase or sale term is a defined accounting term, and may not, in all cases, indicate whether the contract would be "normal" from an operating entity viewpoint). The FASB issued final superseding guidance (DIG Issue C20) on this issue effective October 1, 2003, for the Company. DIG Issue C20 specifies new pricing-related criteria for qualifying as a normal purchase or sale, and it required a special transition adjustment as of October 1, 2003.

PEC determined that it had one existing "normal" contract that was affected by DIG Issue C20. Pursuant to the provisions of DIG Issue C20, PEC recorded a pre-tax fair value loss transition adjustment of $38 million ($23 million after-tax) in the fourth quarter of 2003, which was reported as a cumulative effect of a change in accounting principle. The subject contract meets the DIG Issue C20 criteria for normal purchase or sale and, therefore, was designated as a normal purchase as of October 1, 2003. The liability of $38 million associated with the fair value loss is being amortized to earnings over the term of the related contract.

B. Commodity Derivatives — Cash Flow Hedges

The Company held natural gas cash flow hedging instruments at December 31, 2003 and 2002. The objective for holding these instruments is to manage a portion of the market risk associated with fluctuations in the price of natural gas for the Company's forecasted sales. At December 31, 2003, the Company is hedging exposures to the price variability of natural gas through December 2005.

The total fair value of these instruments at December 31, 2003 and 2002 was a $12 million and a $10 million liability position, respectively. The ineffective portion of commodity cash flow hedges was not material in 2003 and 2002. At December 31, 2003, $7 million of after-tax deferred losses in accumulated other comprehensive income (OCI) are expected to be reclassified to earnings during the next 12 months as the hedged transactions occur. Due to the volatility of the commodities markets, the value in OCI is subject to change prior to its reclassification into earnings.

C. Commodity Derivatives — Economic Hedges and Trading

Nonhedging derivatives, primarily electricity and natural gas contracts, are entered into for trading purposes and for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. The Company manages open positions with strict policies that limit its exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material during 2003, 2002 or 2001, and the Company did not have material outstanding positions in such contracts at December 31, 2003 or 2002.

D. Interest Rate Derivatives — Fair Value or Cash Flow Hedges

The Company manages its interest rate exposure in part by maintaining its variable-rate and fixed-rate exposures within defined limits. In addition, the Company also enters into financial derivative instruments, including, but not limited to, interest rate swaps and lock agreements to manage and mitigate interest rate risk exposure.

The Company uses cash flow hedging strategies to hedge variable interest rates on long-term and short-term debt and to hedge interest rates with regard to future fixed-rate debt issuances. At December 31, 2003 and 2002, the Company held interest rate cash flow hedges, with a varying notional amount and maximum of $195 million, related to variable rate long-term debt. At December 31, 2003, the Company also held interest rate cash flow hedges, with a total notional amount of $400 million, related to projected outstanding balances of commercial paper. At December 31, 2002, the Company also held an interest rate cash flow hedge, with a notional amount of $35 million, related to the issuance of fixed-rate debt in early 2003. The total fair value of these hedges at December 31, 2003 and 2002 was a $6 million and a $13 million liability position, respectively. At December 31, 2003, $7 million of after-tax deferred losses in OCI, including amounts in OCI related to terminated hedges, are expected to be reclassified to earnings during the next 12 months as the hedged interest payments occur. Due to the volatility of interest rates, the value in OCI is subject to change prior to its reclassification into earnings.

The Company uses fair value hedging strategies to manage its exposure to fixed interest rates on long-term debt. At December 31, 2003, the Company had open interest rate fair value hedges with notional amounts totaling $850 million and a total fair value of $4 million liability position. At December 31, 2002, the Company had open interest rate fair value hedges with notional amounts totaling $350 million and a total fair value of $5 million asset position. In addition, at December 31, 2003, the Company had $23 million of net hedging gains related to terminated interest rate fair value hedges, which is reflected in long-term debt and is being amortized over periods ending in 2006 through 2008 coinciding with the maturities of the related debt instruments.

The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by a counterparty, the risk in these transactions is the cost of replacing the agreements at current market rates.

18. RELATED PARTY TRANSACTIONS

Progress Fuels sells coal to PEF for an insignificant profit. These intercompany revenues are eliminated in consolidation; however, in accordance with SFAS No. 71, profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of the sales price through the ratemaking process is probable. The profits for all the years presented were not significant.

The Company sold NCNG to Piedmont Natural Gas Company, Inc. on September 30, 2003 (See Note 3A). Prior to disposition, NCNG sold natural gas to affiliates. During the years ended December 31, 2003, 2002 and 2001, sales of natural gas to affiliates amounted to $11 million, $20 million and $19 million, respectively. These revenues are included in discontinued operations on the Consolidated Statements of Income.

The Company has an outstanding note due to a related trust. The principal outstanding on this note was $309 million at December 31, 2003 (See Note 12A and F).

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

The Company currently provides services through the following business segments: PEC Electric, PEF, Fuels, CCO, Rail Services and Other. Prior to 2003, Fuels and CCO were reported together as the Progress Ventures business segment and corporate costs were included in the Other segment. These reportable segment changes reflect the current management structure.

PEC Electric and PEF are primarily engaged in the generation, transmission, distribution and sale of electric energy in portions of North Carolina, South Carolina and Florida. These electric operations are subject to the rules and regulations of the FERC, the NCUC, the SCPSC and the FPSC. These electric operations also distribute and sell electricity to other utilities, primarily on the east coast of the United States.

Fuels operations, which are located throughout the United States, are involved in natural gas drilling and production, coal terminal services, coal mining, synthetic fuel production, fuel transportation and delivery.

CCO's operations, which are located in the southeastern United States, include nonregulated electric generation operations and marketing activities.

Rail Services' operations include railcar repair, rail parts reconditioning and sales, railcar leasing and sales and scrap metal recycling. These activities include maintenance and reconditioning of salvageable scrap components of railcars, locomotive repair and right-of-way maintenance. Rail Services' operations are located in the United States, Canada and Mexico.

The Other segment, whose operations are in the United States, is composed of other nonregulated business areas including telecommunications and energy service operations and other nonregulated subsidiaries that do not separately meet the disclosure requirements of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." Included in this segment's 2002 losses are asset impairments and certain other after-tax charges related to the telecommunications operations of $225 million, the 2001 results include asset impairments and other after-tax charges of $153 million.

In addition to these reportable operating segments, the Company has other corporate activities that include holding company operations, service company operations and eliminations. These corporate activities have been included in the Other segment in the past. Additionally, earnings from wholesale customers on the regulated plants have previously been reported in both the regulated utilities' results and the results of Progress Ventures (which referred to Fuels and CCO collectively). This activity is now included in the regulated utilities results only. The operations of NCNG, previously reported in the Other segment, were reclassified to discontinued operations and therefore are not included in the results from continuing operations during the periods reported. For comparative purposes, the results have been restated to align with the new business segment structure. The profit or loss of the identified segments plus the loss of Corporate represents the Company's total income from continuing operations.

(in millions)	PEC Electric	PEF	Fuels	CCO CCO	Rail Services[b]	Other	Corporate	Totals
Year ended December 31, 2003								
Revenues								
Unaffiliated	**$3,589**	**$3,152**	**$928**	**$170**	**$846**	**$58**	**$—**	**$8,743**
Intersegment	**—**	**—**	**346**	**—**	**1**	**15**	**(362)**	**—**
Total revenues	**3,589**	**3,152**	**1,274**	**170**	**847**	**73**	**(362)**	**8,743**
Depreciation and amortization	**562**	**307**	**80**	**42**	**20**	**6**	**23**	**1,040**
Total interest charges, net	**194**	**91**	**23**	**4**	**29**	**(1)**	**285**	**625**
Impairment of long-lived assets and investments	**11**	**—**	**17**	**—**	**—**	**10**	**—**	**38**
Income tax (benefit)[b]	**240**	**147**	**(415)**	**8**	**2**	**(4)**	**(87)**	**(109)**
Segment profit (loss)	**515**	**295**	**235**	**20**	**(1)**	**(17)**	**(236)**	**811**
Total assets	**10,854**	**7,306**	**1,170**	**1,747**	**586**	**304**	**4,235**	**26,202**
Capital and investment expenditures	**470**	**548**	**310**	**360**	**103**	**12**	**22**	**1,825**
Year ended December 31, 2002								
Revenues								
Unaffiliated	$3,539	$3,062	$607	$92	$714	$77	$—	$8,091
Intersegment	—	—	329	—	5	14	(348)	—
Total revenues	3,539	3,062	936	92	719	91	(348)	8,091
Depreciation and amortization	524	295	47	20	20	15	17	938
Total interest charges, net	212	106	24	(12)	33	(5)	275	633
Impairment of long-lived assets and investments	—	—	—	—	59	330	—	389
Income tax (benefit)[b]	237	163	(373)	16	(16)	(129)	(56)	(158)
Segment profit (loss)	513	323	176	27	(42)	(243)	(202)	552
Total assets	10,139	6,678	934	1,452	529	318	3,668	23,718
Capital and investment expenditures	624	550	172	682	8	53	20	2,109
Year ended December 31, 2001								
Revenues								
Unaffiliated	$3,344	$3,213	$559	$16	$890	$107	$—	$8,129
Intersegment	—	—	299	—	1	13	(313)	—
Total revenues	3,344	3,213	858	16	891	120	(313)	8,129
Depreciation and amortization	522	453	34	4	36	18	83	1,150
Total interest charges, net	241	113	24	—	41	(7)	261	673
Impairment of long-lived assets and investments	—	—	—	—	—	207	—	207
Income tax (benefit)	264	183	(424)	3	(6)	(57)	(117)	(154)
Segment profit (loss)	468	309	199	4	(12)	(162)	(265)	541
Capital and investment expenditures	824	353	70	195	13	72	—	1,527

[a] *Amounts for the year ended December 31, 2001, reflect cumulative operating results of Rail Services since the acquisition date of November 30, 2000.*

[b] *Amounts for 2003 and 2002 include income tax benefit reallocation from holding company to profitable subsidiaries according to an SEC order.*

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income, gain on the sale of investments, impairment of investments and other income and expense items as discussed below. The components of other, net as shown on the Consolidated Statements of Income for the years ended December 31, are as follows:

(in millions)	2003	2002	2001
Other income			
Net financial trading loss	$(2)	$(2)	$(1)
Net energy brokered for resale	2	2	3
Nonregulated energy and delivery services income	22	29	29
Contingent value obligation unrealized gain (Note 15)	—	28	—
Investment gains	9	30	3
Income from equity investments	9	9	7
AFUDC equity	14	9	9
Other	26	16	5
Total other income	$80	$121	$55
Other expense			
Nonregulated energy and delivery services expenses	20	29	35
Donations	15	21	23
Investment losses	27	18	4
Contingent value obligation unrealized loss (Note 15)	9	—	1
Loss from minority interest	3	—	3
Other	31	26	23
Total other expense	$105	$94	$89
Other, net	$(25)	$27	$(34)

Net financial trading loss represents nonasset-backed trades of electricity and gas. Nonregulated energy and delivery services include power protection services and mass market programs (surge protection, appliance services and area light sales) and delivery, transmission and substation work for other utilities.

21. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

The following table reflects Progress Energy's contractual cash obligations and other commercial commitments in the respective periods in which they are due:

(in millions) Contractual Cash Obligations	2004	2005	2006	2007	2008	Thereafter
Fuel	$1,245	$628	$459	$271	$151	$1,012
Purchased power	427	439	450	459	431	4,711
Construction obligations	112	49	—	—	—	—
Other purchase obligations	28	11	18	11	16	124
Total	$1,812	$1,127	$927	$741	$598	$5,847

FUEL AND PURCHASED POWER

FPC, PEC and PVI have entered into various long-term contracts for coal, gas and oil. Payments under these commitments were $1,207 million, $1,359 million and $1,257 million for 2003, 2002 and 2001, respectively. Estimated annual payments for firm commitments of fuel purchases and transportation costs under these contracts are approximately $1,245 million, $628 million, $459 million, $271 million and $151 million for 2004 through 2008, respectively, with approximately $1,012 million payable thereafter.

Pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between PEC and the North Carolina Eastern Municipal Power Agency (Power Agency), PEC is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, the Harris Plant. In 1993, PEC and Power Agency entered into an agreement to restructure portions of their contracts covering power supplies and interests in jointly owned units. Under the terms of the 1993 agreement, PEC increased the amount of capacity and energy purchased from Power Agency's ownership interest in the Harris Plant, and the buyback period was extended six years through 2007. The estimated minimum annual payments for these purchases, which reflect capacity costs, total approximately $36 million. These contractual purchases totaled $36 million, $36 million and $33 million for 2003, 2002 and 2001, respectively. In 1987, the NCUC ordered PEC to reflect the recovery of the capacity portion of these costs on a levelized basis over the original 15-year buyback period, thereby deferring for future recovery the difference between such costs and amounts collected through rates. At December 31, 2002, PEC had deferred purchased capacity costs, including carrying costs accrued on the deferred balances of $17 million. At December 31, 2003, all previously deferred costs have been expensed.

PEC has a long-term agreement for the purchase of power and related transmission services from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The agreement provides for the purchase of

250 MW of capacity through 2009 with minimum annual payments of approximately $42 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $66 million, $59 million and $63 million for 2003, 2002 and 2001, respectively.

Effective June 1, 2001, PEC executed a long-term agreement for the purchase of power from Skygen Energy LLC's Broad River facility (Broad River). The agreement provides for the purchase of approximately 500 MW of capacity through 2021 with an original minimum annual payment of approximately $16 million, primarily representing capital-related capacity costs. A separate long-term agreement for additional power from Broad River commenced June 1, 2002. This agreement provided for the additional purchase of approximately 300 MW of capacity through 2022 with an original minimum annual payment of approximately $16 million representing capital-related capacity costs. Total purchases under the Broad River agreements amounted to $37 million, $38 million and $21 million in 2003, 2002 and 2001, respectively.

PEF has long-term contracts for approximately 474 MW of purchased power with other utilities, including a contract with the Southern Company for approximately 414 MW of purchased power annually through 2010. PEF can lower these purchases to approximately 200 MW annually with a three-year notice. Total purchases, for both energy and capacity, under these agreements amounted to $141 million, $159 million and $112 million for 2003, 2002 and 2001, respectively. Total capacity payments were $57 million, $51 million and $54 million for 2003, 2002 and 2001, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $60 million annually through 2009 and $30 million annually for 2010.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (qualifying facilities) with expiration dates ranging from 2004 to 2025. These purchased power contracts generally provide for capacity and energy payments. Energy payments for the PEF contracts are based on actual power taken under these contracts. Capacity payments are subject to the qualifying facilities (QFs) meeting certain contract performance obligations. PEF's total capacity purchases under these contracts amounted to $241 million, $232 million and $226 million for 2003, 2002 and 2001, respectively. Minimum expected future capacity payments under these contracts at December 31, 2003, are $257 million, $269 million, $280 million, $289 million and $297 million for 2004 through 2008, respectively, and $4,147 million thereafter. PEC has various pay-for-performance contracts with QFs for approximately 400 MW of capacity expiring at various times through 2009. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $118 million in 2003, $145 million in 2002 and 2001.

CONSTRUCTION OBLIGATIONS

The Company has purchase obligations related to various capital construction projects. Total payments under these contracts were $202 million, $164 million and $24 million for 2003, 2002 and 2001, respectively. Future obligations under these contracts are $112 million and $49 million for 2004 and 2005, respectively.

OTHER PURCHASE OBLIGATIONS

The Company has entered into various other contractual obligations primarily related to service contracts for operational services entered into by the PESC, a PVI parts and services contract, and a PEF service agreement related to the Hines Energy Complex. Payments under these agreements were $17 million, $15 million and $15 million for 2003, 2002 and 2001, respectively. Future obligations under these contracts are $28 million, $11 million, $18 million, $11 million and $16 million for 2004 through 2008, respectively, and $124 million thereafter.

On December 31, 2002, PEC and PVI entered into a contractual commitment to purchase at least $13 million and $4 million, respectively, of capital parts by December 31, 2010. At December 31, 2003, no capital parts have been purchased under this contract.

B. Other Commitments

The Company has certain future commitments related to four synthetic fuel facilities purchased that provide for contingent payments (royalties) of up to $11 million on synthetic fuel sales from each plant annually through 2007. The related agreements were amended in December 2001 to require the payment of minimum annual royalties of approximately $7 million for each plant through 2007. As a result of the amendment, the Company recorded a liability (included in other liabilities and deferred credits on the Consolidated Balance Sheets) and a deferred asset (included in other assets and deferred debits in the Consolidated Balance Sheets), each of approximately $94 million and $114 million at December 31, 2003 and 2002, respectively, representing the minimum amounts due through 2008, discounted at 6.05%. At December 31, 2003 and 2002, the portions of the asset and liability recorded that were classified as current were approximately $24 million. The deferred asset will be amortized to expense each year as synthetic fuel sales are made. The maximum amounts payable under these agreements

remain unchanged. Actual amounts paid under these agreements were approximately $2 million in 2003, $51 million in 2002 and $46 million in 2001. Future expected minimum royalty payments are approximately $26 million for 2004 through 2007 and $7 million for 2008. The large decline in amount paid from 2002 to 2003 is due to the Company's right in the related agreements and their amendments that allow the Company to escrow those payments if certain conditions in the agreements are met. The Company has exercised that right and retained 2003 royalty payments of approximately $48 million pending the establishment of the necessary escrow accounts. Once established, those funds will be placed into escrow.

C. Leases

The Company leases office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Rent expense under operating leases totaled $55 million, $57 million and $63 million for 2003, 2002 and 2001, respectively.

Assets recorded under capital leases at December 31 consist of:

(in millions)	2003	2002
Buildings	$30	$28
Equipment and other	3	3
Less: Accumulated amortization	(10)	(10)
	$23	$21

Equipment and other capital lease assets were written down in conjunction with the impairments of PTC and Caronet during the third quarter of 2002 (See Note 9A).

Minimum annual rental payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable leases at December 31, 2003, are:

(in millions)	Capital Leases	Operating Leases
2004	$4	$38
2005	4	33
2006	4	27
2007	4	22
2008	3	19
Thereafter	31	168
	$50	$307
Less amount representing imputed interest	(20)	
Present value of net minimum lease payments under capital leases	$30	

The Company is also a lessor of land, buildings, railcars and other types of properties it owns under operating leases with various terms and expiration dates. The leased buildings and railcars are depreciated under the same terms as other buildings and railcars included in diversified business property. In 2003, PEC entered into a new operating lease for a building, which minimum annual rental payments are included in the table above, and for 2004 through 2008 are approximately $1 million, $4 million, $4 million, $4 million and $4 million, respectively, with $96 million thereafter. Minimum rentals receivable under noncancelable leases for 2004 through 2008 are approximately $4 million, $4 million, $7 million, $8 million and $14 million, respectively, with $51 million receivable thereafter. These rental receivable totals exclude all leases attributable to Railcar Ltd. which was sold during the first quarter of 2004 (See Note 3B).

PEC and PEF are lessors of electric poles, streetlights and other facilities. Rents received are contingent upon usage and totaled $87 million, $81 million and $78 million for 2003, 2002 and 2001, respectively.

D. Guarantees

As a part of normal business, Progress Energy and certain subsidiaries enter into various agreements providing financial or performance assurances to third parties. Such agreements include guarantees, standby letters of credit and surety bonds. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. At December 31, 2003, management does not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates discussed herein.

Guarantees at December 31, 2003, are summarized in the table below and discussed more fully in the subsequent paragraphs.

(in millions)	
Guarantees issued on behalf of affiliates	
Guarantees supporting nonregulated portfolio and energy marketing activities issued by Progress Energy	$332
Guarantees supporting nuclear decommissioning	276
Guarantee supporting power supply agreements	307
Standby letters of credit	11
Surety bonds	117
Other guarantees	1
Guarantees issued on behalf of third parties	
Other guarantees	13
Total	$1,057

GUARANTEES SUPPORTING NONREGULATED PORTFOLIO AND ENERGY MARKETING ACTIVITIES

Progress Energy has issued approximately $332 million of guarantees on behalf of Progress Ventures (the business unit) and its subsidiaries for obligations under tolling agreements, transmission agreements, gas agreements, construction agreements, fuel procurement agreements and trading operations. Approximately $103 million of these guarantees were issued during the year to support energy marketing activities. The majority of the marketing contracts supported by the guarantees contain language regarding downgrade events, ratings triggers, monthly netting of exposure and/or payments and offset provisions in the event of a default. Based upon current business levels at December 31, 2003, if the Company's ratings were to decline below investment grade, the Company estimates that it may have to deposit cash or provide letters of credit or other cash collateral of approximately $56 million for the benefit of the Company's counterparties to support ongoing operations within a 90-day period.

GUARANTEES SUPPORTING NUCLEAR DECOMMISSIONING

In 2003, PEC determined that its external funding levels did not fully meet the nuclear decommissioning financial assurance levels required by the NRC. Therefore, PEC met the financial assurance requirements by obtaining guarantees from Progress Energy in the amount of $276 million.

GUARANTEES SUPPORTING POWER SUPPLY AGREEMENTS

On March 20, 2003, PVI entered into a definitive agreement with Williams Energy Marketing and Trading, a subsidiary of The Williams Companies, Inc., to acquire a long-term, full-requirements power supply agreement at fixed prices with Jackson. The power supply agreement included a performance guarantee by Progress Energy. The transaction closed during the second quarter of 2003. The Company issued a payment and performance guarantee to Jackson related to the power supply agreement of $280 million. In the event that Progress Energy's credit ratings fall below investment grade, Progress Energy may be required to provide additional security for this guarantee in form and amount (not to exceed $280 million) acceptable to Jackson. During the third quarter of 2003, PVI entered into an agreement with Morgan Stanley Capital Group Inc. to fulfill Morgan Stanley's obligations to schedule resources and supply energy to Oglethorpe Power Corporation of Georgia through March 31, 2005. The Company issued a payment and performance guarantee to Morgan Stanley related to the power supply agreement. In the event that Progress Energy's credit ratings fall below investment grade, Progress Energy estimates that it may have to deposit cash or provide letters of credit or other cash collateral of approximately $27 million for the benefit of Morgan Stanley at December 31, 2003.

STANDBY LETTERS OF CREDIT

The Company has issued $11 million of standby letters of credit to financial institutions for the benefit of third parties that have extended credit to the Company and certain subsidiaries. These letters of credit have been issued primarily for the purpose of supporting payments of trade payables, securing performance under contracts and lease obligations and self-insurance for workers' compensation. If a subsidiary does not pay amounts when due under a covered contract, the counterparty may present its claim for payment to the financial institution, which will in turn request payment from the Company. Any amounts owed by the Company's subsidiaries are reflected in the accompanying Consolidated Balance Sheets.

SURETY BONDS

At December 31, 2003, the Company had $117 million in surety bonds purchased primarily for purposes such as providing workers' compensation coverage, obtaining licenses, permits, rights-of-way and project performance. To the extent liabilities are incurred as a result of the activities covered by the surety bonds, such liabilities are included in the accompanying Consolidated Balance Sheets.

OTHER GUARANTEES

The Company has other guarantees outstanding of approximately $14 million. Included in the $14 million are $13 million of guarantees issued on behalf of third parties of which $3 million is related to obligations on leasing arrangements and $10 million is in support of synthetic fuel operations at a third-party plant. The Company estimates it will have to perform under the guarantees related to the leasing agreements and as such $3 million has been accrued and is reflected in the accompanying Consolidated Balance Sheets. The remaining $1 million in affiliate guarantees is related primarily to prompt performance payments, lease obligations and other payments subject to contingencies.

E. Claims and Uncertainties

1. The Company is subject to federal, state and local regulations addressing hazardous and solid waste management, air and water quality and other environmental matters.

HAZARDOUS AND SOLID WASTE MANAGEMENT

Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. The principal

regulatory agency that is responsible for a specific former manufactured gas plant (MGP) site depends largely upon the state in which the site is located. There are several MGP sites to which both electric utilities have some connection. In this regard, both electric utilities and other potentially responsible parties (PRPs) are participating in, investigating and, if necessary, remediating former MGP sites with several regulatory agencies, including, but not limited to, the U.S. Environmental Protection Agency (EPA), the Florida Department of Environmental Protection (FDEP) and the North Carolina Department of Environment and Natural Resources, Division of Waste Management (DWM). In addition, the Company and its subsidiaries are periodically notified by regulators such as the EPA and various state agencies of their involvement or potential involvement in sites, other than MGP sites, that may require investigation and/or remediation. A discussion of these sites by legal entity follows.

PEC

There are nine former MGP sites and other sites associated with PEC that have required or are anticipated to require investigation and/or remediation costs. PEC received insurance proceeds to address costs associated with environmental liabilities related to its involvement with some MGP sites. All eligible expenses related to these are charged against a specific fund containing these proceeds. At December 31, 2003, approximately $9 million remains in this centralized fund with a related accrual of $9 million recorded for the associated expenses of environmental issues. PEC does not believe that it can provide an estimate of the reasonably possible total remediation costs beyond what is currently accrued due to the fact that investigations have not been completed at all sites. This accrual has been recorded on an undiscounted basis. PEC measures its liability for these sites based on available evidence including its experience in investigating and remediating environmentally impaired sites. The process often involves assessing and developing cost-sharing arrangements with other PRPs. PEC will accrue costs for the sites to the extent its liability is probable and the costs can be reasonably estimated. Presently, PEC cannot determine the total costs that may be incurred in connection with the remediation of any of these MGP sites.

In September 2003, the Company sold NCNG to Piedmont Natural Gas Company, Inc. As part of the sales agreement, the Company retained responsibility to remediate five former NCNG MGP sites, all of which also are associated with PEC, to state standards pursuant to an Administrative Order by consent. These sites are anticipated to have investigation or remediation costs associated with them. NCNG had previously accrued approximately $2 million for probable and reasonably estimable remediation costs at these sites. These accruals have been recorded on an undiscounted basis. At the time of the sale, the liability for these costs and the related accrual was transferred to PEC. PEC does not believe it can provide an estimate of the reasonably possible total remediation costs beyond the accrual because investigations have not been completed at all sites. Therefore, PEC cannot currently determine the total costs that may be incurred in connection with the investigation and/or remediation of all sites.

PEF

At December 31, 2003, PEF has accrued $18 million for probable and estimable costs related to various environmental sites. Of this accrual, $12 million is for costs associated with the remediation of distribution transformers which are more fully discussed below. The remaining $6 million is related to two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation costs. PEF does not believe that it can provide an estimate of the reasonably possible total remediation costs beyond what is currently accrued.

In 2002, PEF accrued approximately $3 million for investigation and remediation associated with distribution transformers and received approval from the FPSC for annual recovery of these environmental costs through the Environmental Cost Recovery Clause (ECRC). In September 2003, PEF accrued an additional $15 million for similar environmental costs as a result of increased sites and estimated costs per site. PEF plans to seek approval from the FPSC to recover these costs through the ECRC. As more activity occurs at these sites, PEF will assess the need to adjust the accruals.

These accruals have been recorded on an undiscounted basis. PEF measures its liability for these sites based on available evidence including its experience in investigating and remediating environmentally impaired sites. This process often includes assessing and developing cost-sharing arrangements with other PRPs. Presently, PEF cannot determine the total costs that may be incurred in connection with the remediation of all sites.

Florida Progress Corporation

In 2001, FPC sold its Inland Marine Transportation business operated by MEMCO Barge Line, Inc. to AEP Resources, Inc. FPC established an accrual to address indemnities and retained an environmental liability associated with the transaction. FPC estimates that its contractual liability to AEP Resources, Inc., associated with Inland Marine Transportation, is $4 million at December 31, 2003, and has accrued such amount. The previous accrual of $10 million was reduced in 2003 based on a change in estimate. This accrual has been determined on an undiscounted

basis. FPC measures its liability for this site based on estimable and probable remediation scenarios. The Company believes that it is not reasonably probable that additional costs, which cannot be currently estimated, will be incurred related to the environmental indemnification provision beyond the amount accrued. The Company cannot predict the outcome of this matter.

PEC, PEF and Fuels have filed claims with the Company's general liability insurance carriers to recover costs arising out of actual or potential environmental liabilities. Some claims have been settled and others are still pending. While the Company cannot predict the outcome of these matters, the outcome is not expected to have a material effect on the consolidated financial position or results of operations.

The Company is also currently in the process of assessing potential costs and exposures at other environmentally impaired sites. As the assessments are developed and analyzed, the Company will accrue costs for the sites to the extent the costs are probable and can be reasonably estimated.

Certain historical sites exist that are being addressed voluntarily by PVI and FPC. An immaterial accrual has been established to address investigation expenses related to these sites. The Company cannot determine the total costs that may be incurred in connection with these sites. According to current information, these future costs are not expected to be material to the Company's financial condition or results of operations.

Rail Services is voluntarily addressing certain historical waste sites. An immaterial accrual has been established to address estimable costs. The Company cannot determine the total costs that may be incurred in connection with these sites. According to current information, these future costs are not expected to be material to the Company's financial condition or results of operations.

AIR QUALITY

There has been and may be further proposed federal legislation requiring reductions in air emissions for NOx, SO_2, carbon dioxide and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multi-pollutant approach to air pollution control could involve significant capital costs which could be material to the Company's consolidated financial position or results of operations. Some companies may seek recovery of the related cost through rate adjustments or similar mechanisms. Control equipment that will be installed on North Carolina fossil generating facilities as part of the North Carolina legislation discussed below may address some of the issues outlined above. However, the Company cannot predict the outcome of this matter.

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants in an effort to determine whether modifications at those facilities were subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. Both PEC and PEF were asked to provide information to the EPA as part of this initiative and cooperated in providing the requested information. The EPA initiated civil enforcement actions against other unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements calling for expenditures by these unaffiliated utilities, ranging from $1.0 billion to $1.4 billion. A utility that was not subject to a civil enforcement action settled its New Source Review issues with the EPA for $300 million. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the companies may seek recovery of the related cost through rate adjustments or similar mechanisms. The Company cannot predict the outcome of this matter.

In 1998, the EPA published a final rule at Section 110 of the Clean Air Act addressing the regional transport of ozone (NOx SIP Call). The EPA's rule requires 23 jurisdictions, including North Carolina, South Carolina and Georgia, but not Florida, to further reduce NOx emissions in order to attain preset state NOx emission levels by May 31, 2004. PEC is currently installing controls necessary to comply with the rule. Capital expenditures to meet these measures in North and South Carolina could reach approximately $370 million, which has not been adjusted for inflation. The Company has spent approximately $258 million to date related to these expenditures. Increased operation and maintenance costs relating to the NOx SIP Call are not expected to be material to the Company's results of operations. Further controls are anticipated as electricity demand increases. The Company cannot predict the outcome of this matter.

In July 1997, the EPA issued final regulations establishing a new 8-hour ozone standard. In October 1999, the District of Columbia Circuit Court of Appeals ruled against the EPA with regard to the federal 8-hour ozone standard. The U.S. Supreme Court has upheld, in part, the District of Columbia Circuit Court of Appeals' decision. Designation of areas that do not attain the standard is proceeding, and further litigation and rulemaking on this and other aspects of the standard are anticipated. North Carolina adopted the federal 8-hour ozone standard and is proceeding with the implementation process. North Carolina has promulgated final regulations, which will require PEC

to install NOx controls under the state's 8-hour standard. The costs of those controls are included in the $370 million cost estimate above. However, further technical analysis and rulemaking may result in a requirement for additional controls at some units. The Company cannot predict the outcome of this matter.

The EPA published a final rule approving petitions under Section 126 of the Clean Air Act. This rule, as originally promulgated, required certain sources to make reductions in NOx emissions by May 1, 2003. The final rule also includes a set of regulations that affect NOx emissions from sources included in the petitions. The North Carolina coal-fired electric generating plants are included in these petitions. Acceptable state plans under the NOx SIP Call can be approved in lieu of the final rules the EPA approved as part of the Section 126 petitions. In April 2002, the EPA published a final rule harmonizing the dates for the Section 126 rule and the NOx SIP Call. The new compliance date for all affected sources is now May 31, 2004, rather than May 1, 2003. The EPA has approved North Carolina's NOx SIP Call rule and has indicated it will rescind the Section 126 rule in a future rulemaking. The Company expects a favorable outcome of this matter.

In June 2002, legislation was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from coal-fired power plants. Progress Energy expects its capital costs to meet these emission targets will be approximately $813 million by 2013. PEC has expended approximately $30 million of these capital costs through December 31, 2003. PEC currently has approximately 5,100 MW of coal-fired generation capacity in North Carolina that is affected by this legislation. The legislation requires the emissions reductions to be completed in phases by 2013, and applies to each utility's total system rather than setting requirements for individual power plants. The legislation also freezes the utilities' base rates for five years unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the utilities' last general rate case. Further, the legislation allows the utilities to recover from their retail customers the projected capital costs during the first 7 years of the ten-year compliance period beginning on January 1, 2003. The utilities must recover at least 70% of their projected capital costs during the 5-year rate freeze period. PEC has recognized $74 million in 2003. Pursuant to the law, PEC entered into an agreement with the state of North Carolina to transfer to the state all future emissions allowances it generates from overcomplying with the federal emission limits when these units are completed. The law also requires the state to undertake a study of mercury and carbon dioxide emissions in North Carolina. Operation and maintenance costs will increase due to the additional personnel, materials and general maintenance associated with the equipment. Operation and maintenance expenses are recoverable through base rates, rather than as part of this program. Progress Energy cannot predict the future regulatory interpretation, implementation or impact of this law.

In 2004, a bill was introduced in the Florida legislature that would require significant reductions in NOx, SO_2 and particulate emissions from certain coal, natural gas and oil-fired generating units owned or operated by investor-owned electric utilities, including PEF. The NOx and SO_2 reductions would be effective beginning with calendar year 2010, and the particulate reductions would be effective beginning with calendar year 2012. Under the proposed legislation, the FPSC would be authorized to allow the utilities to recover the costs of compliance with the emission reductions over a period not greater than seven years beginning in 2005, but the utilities' rate would be frozen at 2004 levels for at least five years of the maximum recovery period. The Company cannot predict the outcome of this matter.

In 1997, the EPA's Mercury Study Report and Utility Report to Congress conveyed that mercury is not a risk to the average American and expressed uncertainty about whether reductions in mercury emissions from coal-fired power plants would reduce human exposure. Nevertheless, the EPA determined in 2000 that regulation of mercury emissions from coal-fired power plants was appropriate. In 2003, the EPA proposed two alternative control plans that would limit mercury emissions from coal-fired power plants. The first, a Maximum Achievable Control Technology (MACT) standard applicable to every coal-fired plant, would require compliance in 2008. The second, a national mercury cap and trade program, would require limits to be met in two phases, 2010 and 2018. The mercury rule is expected to become final in December 2004. Achieving compliance with either proposal could involve significant capital costs which could be material to the Company's consolidated financial position or results of operations. The Company cannot predict the outcome of this matter.

In conjunction with the proposed mercury rule, the EPA proposed a MACT standard to regulate nickel emissions from residual oil-fired units. The agency estimates the proposal will reduce national nickel emissions to approximately 103 tons. The rule is expected to become final in December 2004.

In December 2003, the EPA released its proposed Interstate Air Quality Rule (commonly known as the Fine

Particulate Transport Rule and/or the Regional Transport Rule). The EPA's proposal requires 28 jurisdictions, including North Carolina, South Carolina, Georgia and Florida, to further reduce NOx and SO_2 emissions in order to attain preset state emissions levels (which have not yet been determined). The rule is expected to become final in 2004. The installation of controls necessary to comply with the rule could involve significant capital costs.

WATER QUALITY

As a result of the operation of certain control equipment needed to address the air quality issues outlined above, new wastewater streams will be generated at the applicable facilities. Integration of these new wastewater streams into the existing wastewater treatment processes may result in permitting, construction and treatment challenges to PEC in the immediate and extended future.

After many years of litigation and settlement negotiations the EPA published regulations in February 2004 for the implementation of Section 316(b) of the Clean Water Act. The purpose of these regulations is to minimize adverse environmental impacts caused by cooling water intake structures and intake systems. Over the next several years these regulations will impact the larger base load generation facilities and may require the facilities to mitigate the effects to aquatic organisms by constructing intake modifications or undertaking other restorative activities. Substantial costs could be incurred by the facilities in order to comply with the new regulation. The Company cannot predict the outcome and impacts to the facilities at this time.

The EPA has published for comment a draft Environmental Impact Statement (EIS) for surface coal mining (sometimes referred to as "mountaintop mining") and valley fills in the Appalachian coal region, where Progress Fuels currently operates a surface mine and may operate others in the future. The final EIS, when published, may affect regulations for the permitting of mines and the cost of compliance with environmental regulations. Regulatory changes for mining may also affect the cost of fuel for the PEC and PEF coal-fueled electric-generating plants. The Company cannot predict the outcome of this matter.

OTHER ENVIRONMENTAL MATTERS

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of carbon dioxide and other greenhouse gases. The United States has not adopted the Kyoto Protocol; however, a number of carbon dioxide emissions control proposals have been advanced in Congress and by the Bush administration. The Bush administration favors voluntary programs. Reductions in carbon dioxide emissions to the levels specified by the Kyoto Protocol and some legislative proposals could be materially adverse to the Company's consolidated financial position or results of operations if associated costs cannot be recovered from customers. The Company favors the voluntary program approach recommended by the administration, and is evaluating options for the reduction, avoidance and sequestration of greenhouse gases. However, the Company cannot predict the outcome of this matter.

2. As required under the Nuclear Waste Policy Act of 1982, PEC and PEF each entered into a contract with the DOE under which the DOE agreed to begin taking spent nuclear fuel by no later than January 31, 1998. All similarly situated utilities were required to sign the same standard contract.

In April 1995, the DOE issued a final interpretation that it did not have an unconditional obligation to take spent nuclear fuel by January 31, 1998. In *Indiana Michigan Power v. DOE*, the Court of Appeals vacated the DOE's final interpretation and ruled that the DOE had an unconditional obligation to begin taking spent nuclear fuel. The Court did not specify a remedy because the DOE was not yet in default.

After the DOE failed to comply with the decision in *Indiana Michigan Power v. DOE*, a group of utilities petitioned the Court of Appeals in *Northern States Power (NSP) v. DOE*, seeking an order requiring the DOE to begin taking spent nuclear fuel by January 31, 1998. The DOE took the position that their delay was unavoidable, and the DOE was excused from performance under the terms and conditions of the contract. The Court of Appeals found that the delay was not unavoidable, but did not order the DOE to begin taking spent nuclear fuel, stating that the utilities had a potentially adequate remedy by filing a claim for damages under the contract.

After the DOE failed to begin taking spent nuclear fuel by January 31, 1998, a group of utilities filed a motion with the Court of Appeals to enforce the mandate in *NSP v. DOE*. Specifically, this group of utilities asked the Court to permit the utilities to escrow their waste fee payments, to order the DOE not to use the waste fund to pay damages to the utilities, and to order the DOE to establish a schedule for disposal of spent nuclear fuel. The Court denied this motion based primarily on the grounds that a review of the matter was premature, and that some of the requested remedies fell outside of the mandate in *NSP v. DOE*.

Subsequently, a number of utilities each filed an action for damages in the Federal Court of Claims. The U.S. Circuit Court of Appeals (Federal Circuit) ruled that utilities may sue the DOE for damages in the Federal Court of Claims instead of having to file an administrative claim with the DOE.

On January 14, 2004, PEC and PEF filed a complaint with the United States Court of Federal Claims against the DOE claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from various Progress Energy facilities on or before January 31, 1998. Damages due to DOE's breach will likely exceed $100 million. Similar suits have been initiated by over two dozen other utilities.

In July 2002, Congress passed an override resolution to Nevada's veto of DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nevada. DOE plans to submit a license application for the Yucca Mountain facility by the end of 2004. On November 5, 2003, Congressional negotiators approved $580 million for fiscal year 2004 for the Yucca Mountain project, $123 million more than the previous year. PEC and PEF cannot predict the outcome of this matter.

With certain modifications and additional approval by the NRC including the installation of onsite dry storage facilities at Robinson (2005) and Brunswick (2008), PEC's spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on PEC's system through the expiration of the current operating licenses for all of PEC's nuclear generating units. PEF currently is storing spent nuclear fuel onsite in spent fuel pools. PEF is seeking renewal of the current CR3 operating license. CR3 has sufficient storage capacity in place for fuel consumed through the end of the expiration of the current license in 2016. If PEF receives approval on its CR3 operating license renewal, additional dry storage may be necessary.

3. In November of 2001, Strategic Resource Solutions Corp. (SRS) filed a claim against the San Francisco Unified School District (the District) and other defendants claiming that SRS is entitled to approximately $10 million in unpaid contract payments and delay and impact damages related to the District's $30 million contract with SRS. On March 4, 2002, the District filed a counterclaim, seeking compensatory damages and liquidated damages in excess of $120 million, for various claims, including breach of contract and demand on a performance bond. SRS has asserted defenses to the District's claims. SRS has amended its claims and asserted new claims against the District and other parties, including a former SRS employee and a former District employee.

On March 13, 2003, the City Attorney and the District filed new claims in the form of a cross-complaint against SRS, Progress Energy, Inc., Progress Energy Solutions, Inc., and certain individuals, alleging fraud, false claims, violations of California statutes, and seeking compensatory damages, punitive damages, liquidated damages, treble damages, penalties, attorneys' fees and injunctive relief. The filing states that the City and the District seek "more than $300 million in damages and penalties." PEC was added as a cross-defendant later in 2003.

The Company, SRS, Progress Energy Solutions, Inc. and PEC all have denied the District's allegations and cross-claims. Discovery is in progress in the matter. The case has been assigned to a judge under the Sacramento County superior court's case management rules, and the judge and the parties have been conferring on scheduling and processes to narrow or resolve issues, if possible, and to get the case ready for trial. No trial date has been set. SRS and the Company are vigorously defending and litigating all of these claims. In November 2003, PEC filed a motion to dismiss the plaintiffs' first amended complaint. The Company cannot predict the outcome of this matter, but will vigorously defend against the allegations.

4. On August 21, 2003, PEC was served as a co-defendant in a purported class action lawsuit styled as *Collins v. Duke Energy Corporation et al*, Civil Action No. 03CP404050, in South Carolina's Circuit Court of Common Pleas for the Fifth Judicial Circuit. PEC is one of three electric utilities operating in South Carolina named in the suit. The plaintiffs are seeking damages for the alleged improper use of electric easements but have not asserted a dollar amount for their damage claims. The complaint alleges that the licensing of attachments on electric utility poles, towers and other structures to nonutility third parties or telecommunication companies for other than the electric utilities' internal use along the electric right-of-way constitutes a trespass.

On September 19, 2003, PEC filed a motion to dismiss all counts of the complaint on substantive and procedural grounds. On October 6, 2003, the plaintiffs filed a motion to amend their complaint. PEC believes the amended complaint asserts the same factual allegations as are in the original complaint and also seeks money damages and injunctive relief. The court has not yet held any hearings or made any rulings in this case. PEC cannot predict the outcome of this matter, but will vigorously defend against the allegations.

5. The Company and its subsidiaries are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, accruals have been made in accordance with SFAS No. 5, "Accounting for Contingencies," to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on the Company's consolidated results of operations or financial position.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (UNAUDITED)

(in millions, except per share data)	2003	2002	2001	2000	1999
Results of Operations[a][b]					
Operating revenues	$8,743	$8,091	$8,129	$3,769	$3,265
Operating expenses	(7,381)	(7,081)	(6,893)	(3,085)	(2,423)
Other income (expense)	(35)	17	(176)	234	(31)
Interest charges, net	(625)	(633)	(673)	(243)	(170)
Income taxes	109	158	154	(197)	(258)
Net Income from Continuing Operations	$811	$552	$541	$478	$383
Balance Sheet Data at Year-end[b]					
Total utility plant, net[d]	$14,434	$13,601	$13,357	$12,795	$7,741
Total assets[d]	$26,202	$24,208	$23,647	$22,842	$10,655
Capitalization					
Common stock equity	$7,444	$6,677	$6,004	$5,424	$3,413
Preferred stock-redemption not required	93	93	93	93	59
Long-term debt, net	9,934	9,747	8,619	4,904	2,162
Current portion of long-term debt	868	275	688	184	197
Short-term obligations	4	695	942	4,959	1,035
Total Capitalization and Total Debt	$18,343	$17,487	$16,346	$15,564	$6,866
Other Financial Data					
Return on average common stock equity (percent)	11.07	8.44	9.41	13.04	11.89
Ratio of earnings to fixed charges	2.03	1.52	1.53	3.42	4.28
Number of common shareholders of record	70,159	72,792	75,673	80,289	67,221
Book value per common share	$30.94	$28.73	$28.20	$27.17	$22.31
Basic earnings per common share					
Income from continuing operations	$3.42	$2.54	$2.64	$3.04	$2.58
Net income	3.30	2.43	2.65	3.04	2.56
Diluted earnings per common share					
Income from continuing operations	$3.40	$2.53	$2.63	$3.03	$2.58
Net income	3.28	2.42	2.64	3.03	2.55
Dividends declared per common share	$2.26	$2.20	$2.14	$2.08	$2.02
Dividend payout (percent)	68.5	90.5	80.8	68.4	78.9
Energy Supply — Electric Utility (millions of kWh)[a]					
Generated					
Steam	51,501	49,734	48,732	31,132	28,260
Nuclear	30,576	30,126	27,301	23,857	22,451
Hydro	955	491	245	441	520
Combustion turbines/combined cycle	7,819	8,522	6,644	1,337	435
Purchased	13,848	14,305	14,469	5,724	5,132
Total energy, supply (Company share)	104,699	103,178	97,391	62,491	56,798
Joint-owner share[c]	5,213	5,258	4,886	4,505	4,353
Total System Energy Supply	109,912	108,436	102,277	66,996	61,151

[a] *Results of operations and energy supply data includes information for Florida Progress Corporation since November 30, 2000, the date of acquisition.*

[b] *All Results of Operations and Balance Sheet data have been restated for discontinued operations.*

[c] *Amounts are net of Company's purchases from joint-owners.*

[d] *Total utility plant, net and total assets have been restated for cost of removal.*

RECONCILIATION OF ONGOING EARNINGS PER SHARE TO REPORTED GAAP EARNINGS PER SHARE (UNAUDITED)

December 31,	2003	2002	2001
Ongoing earnings per share	$3.56	$3.81	$3.40
Contingent value obligation mark-to-market	(0.04)	0.13	—
NCNG discontinued operations	(0.03)	(0.11)	—
Cumulative effect of accounting changes	(0.09)	—	—
Impairments and one-time charges	(0.10)	(1.22)	(0.75)
Ice storm impact	—	(0.08)	—
PEF retroactive revenue refund	—	(0.10)	—
Reported GAAP earnings per share	$3.30	$2.43	$2.65

Contingent Value Obligation (CVO) Mark-to-Market

In connection with the acquisition of Florida Progress Corporation, Progress Energy issued 98.6 million CVOs. Each CVO represents the right to receive contingent payments based on after-tax cash flows above certain levels of four synthetic fuel facilities purchased by subsidiaries of Florida Progress Corporation in October 1999. The CVOs are debt instruments and, under GAAP, are valued at market value. Unrealized gains and losses from changes in market value are recognized in earnings each quarter. Since changes in the market value of the CVOs do not affect the Company's underlying obligation, management does not consider the adjustment a component of ongoing earnings.

NCNG Discontinued Operations

The operations of NCNG are reported as discontinued operations due to its sale, and therefore management does not believe this activity is representative of the ongoing operations of the Company.

Cumulative Effect of Accounting Changes

Progress Energy recorded the cumulative effect of changes in accounting principles due to the adoption of new FASB accounting guidance. The impact to Progress Energy was due primarily to the new FASB guidance related to the accounting for certain contracts. Due to the nonrecurring nature of the adjustment, management believes it is not representative of the 2003 operations of Progress Energy.

Impairments and One-Time Charges

During the fourth quarter of 2003, the Company recorded after-tax impairments of its Affordable Housing portfolio and certain assets at the Kentucky May Coal Company. During the fourth quarter of 2002, the Company committed to a divestiture plan for Railcar, Ltd., which is primarily engaged in rail car leasing, and recorded an estimated loss on assets held for sale. During the third quarter of 2002, the Company recorded an after-tax impairment and one-time charge of PTC's and Caronet's assets. Progress Energy also wrote off the remaining amount of its investment in Interpath. During 2001, the Company recorded asset impairment, primarily goodwill, and other one-time charges related to SRS. In addition, the Company recorded an impairment for other-than-temporary declines in the fair value of its investment in Interpath. Management does not believe these impairments and one-time charges are representative of the ongoing operations of the Company.

Ice Storm Impact

During the fourth quarter of 2002, the Company experienced a severe ice storm in the Carolinas that caused extensive damage to the distribution system. Due to the extensive costs associated with the storm damage, management believes the restoration costs are not representative of the 2002 ongoing operations of Progress Energy Carolinas.

PEF Retroactive Revenue Refund

The one-time retroactive rate refund under the Progress Energy Florida rate settlement in March 2002 was related to funds collected during the period between March 13, 2001, when the prior rate agreement in Florida expired, and March 27, 2002, the date the parties entered into the settlement agreement. Due to the nonrecurring nature of the refund, management believes it is not representative of the 2002 operations of Progress Energy Florida.

Notice of Annual Meeting

Progress Energy's 2004 annual meeting of shareholders will be held on May 12, 2004, at 10:00 a.m. at the Fletcher Opera Theater, BTI Center for the Performing Arts, in Raleigh, NC. A formal notice of the meeting with a proxy statement will be mailed to shareholders in early April.

Transfer Agent and Registrar Mailing Address

Progress Energy, Inc.
c/o EquiServe Trust Company
P. O. Box 43012
Providence, RI 02940-3012
Toll-free phone number: 1-866-290-4388

Shareholder Information and Inquiries

Information on your account is available 24 hours a day, seven days a week by calling our stock transfer agent's shareholder information line. This automated system features Progress Energy's common stock closing price, dividend information and stock transfer information. Call toll-free 1-866-290-4388.

Other questions concerning stock ownership may be directed to Progress Energy's Shareholder Relations. Call toll-free 1-800-662-7232 or write to the following address:

Progress Energy, Inc.
Shareholder Relations
P. O. Box 1551
Raleigh, NC 27602-1551

Stock Listings

Progress Energy's common stock is listed and traded under the symbol PGN on the New York Stock Exchange in addition to regional stock exchanges across the United States.

Shareholder Programs

Progress Energy offers the Progress Energy Investor Plus Plan, a direct stock purchase and dividend reinvestment plan, and direct deposit of cash dividends to bank accounts for the convenience of shareholders. For information on these programs, contact Shareholder Relations at the above address or call us toll-free at 1-800-662-7232.

Proxy material, including the annual report, can be electronically delivered to shareholders. Electronic delivery provides immediate access to proxy material and allows Internet voting while saving printing and mailing costs. To take advantage of electronic delivery of proxy material, go to www.econsent.com/pgn and follow the instructions.

We also offer online access to shareholder accounts via the Internet. To obtain online access to your shareholder account, go to www.equiserve.com. If you have access to Progress Energy's annual report at your address, and do not want to receive a copy for your shareholder account, please call our transfer agent, EquiServe, toll-free at 1-866-290-4388 to discontinue receiving annual reports by mail.

Securities Analyst Inquiries

Securities analysts, portfolio managers and representatives of financial institutions seeking information about Progress Energy should contact Robert F. Drennan, Jr., Manager, Investor Relations, at the corporate headquarters address, or call (919) 546-7474.

Additional Information

Progress Energy files periodic reports with the Securities and Exchange Commission that contain additional information about the company. Copies are available to shareholders upon written request to the company's Treasurer at the corporate headquarters address.

This annual report is submitted for shareholders' information. It is not intended for use in connection with any sale or purchase of, or any offer or solicitation of offers to buy or sell, securities.

COVER: Bartow Plant, St. Petersburg, FL

Thanks to all of the Progress Energy employees who participated in the 2003 Annual Report:

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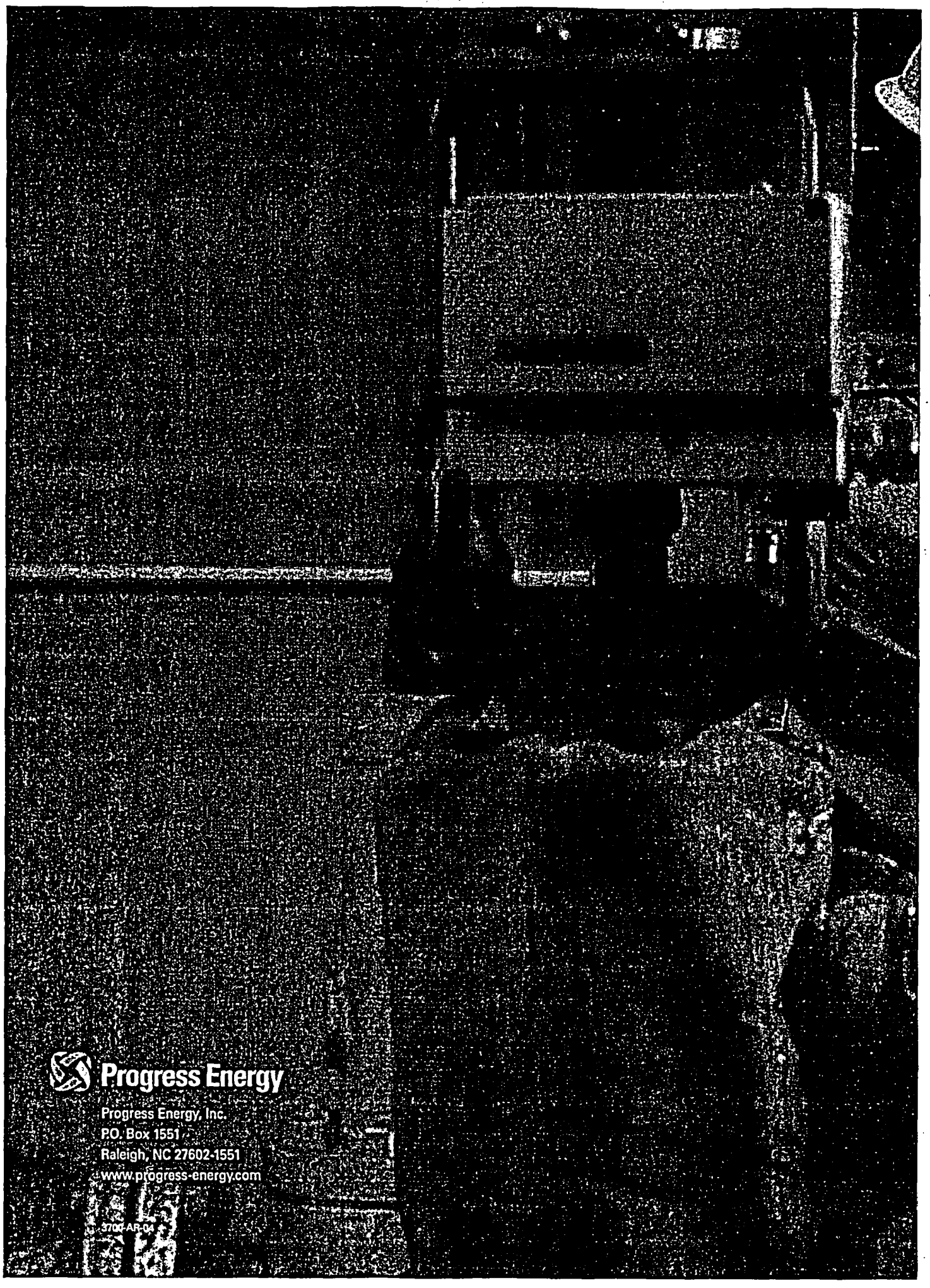

Progress Energy

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