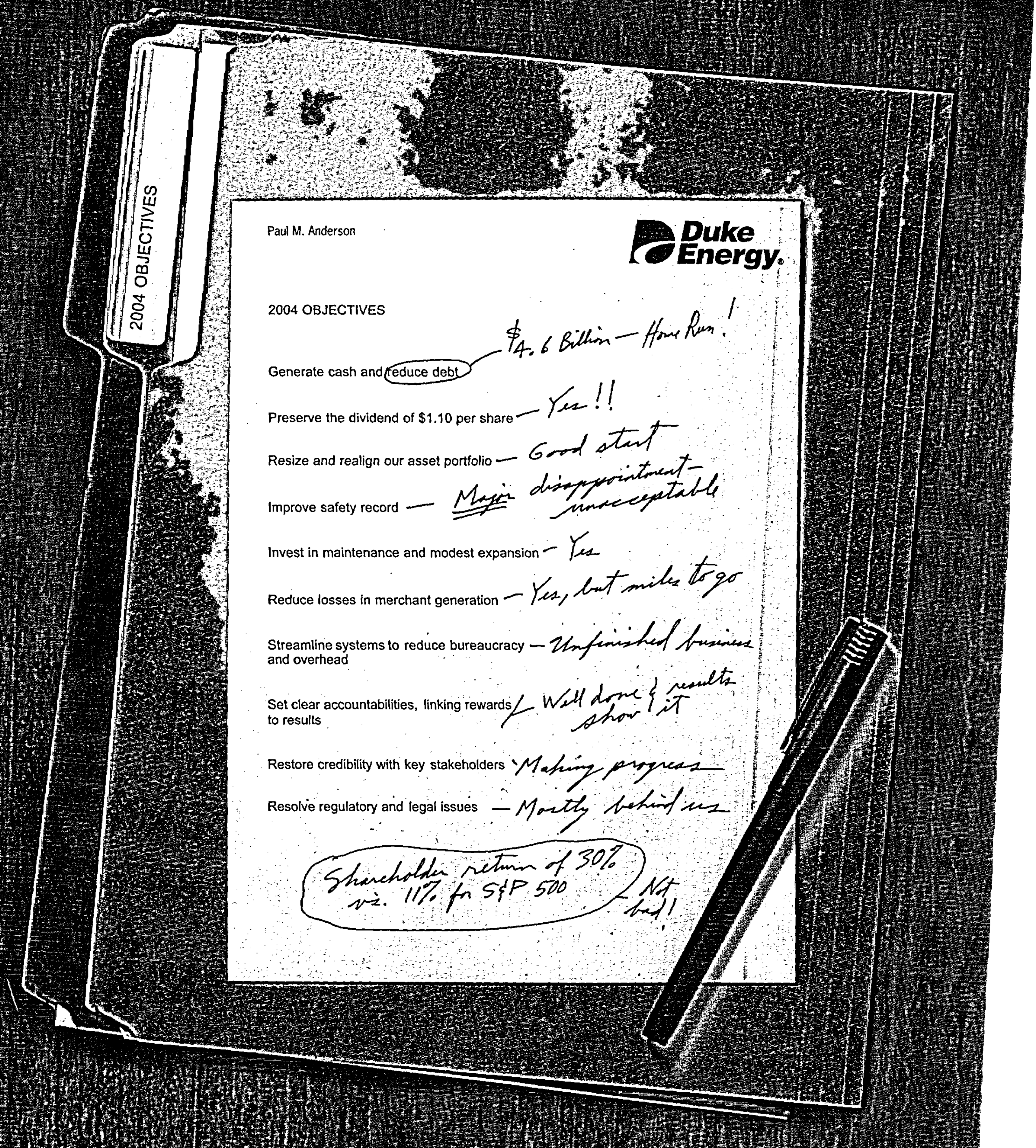
Duke Energy 2004 Summary Annual Report



Paul M. Anderson

Duke Energy.

2004 OBJECTIVES

Generate cash and reduce debt — $4.6 Billion — Home Run!

Preserve the dividend of $1.10 per share — Yes!!

Resize and realign our asset portfolio — Good start

Improve safety record — Major disappointment — unacceptable

Invest in maintenance and modest expansion — Yes

Reduce losses in merchant generation — Yes, but miles to go

Streamline systems to reduce bureaucracy and overhead — Unfinished business

Set clear accountabilities, linking rewards to results — Well done & results show it

Restore credibility with key stakeholders — Making progress

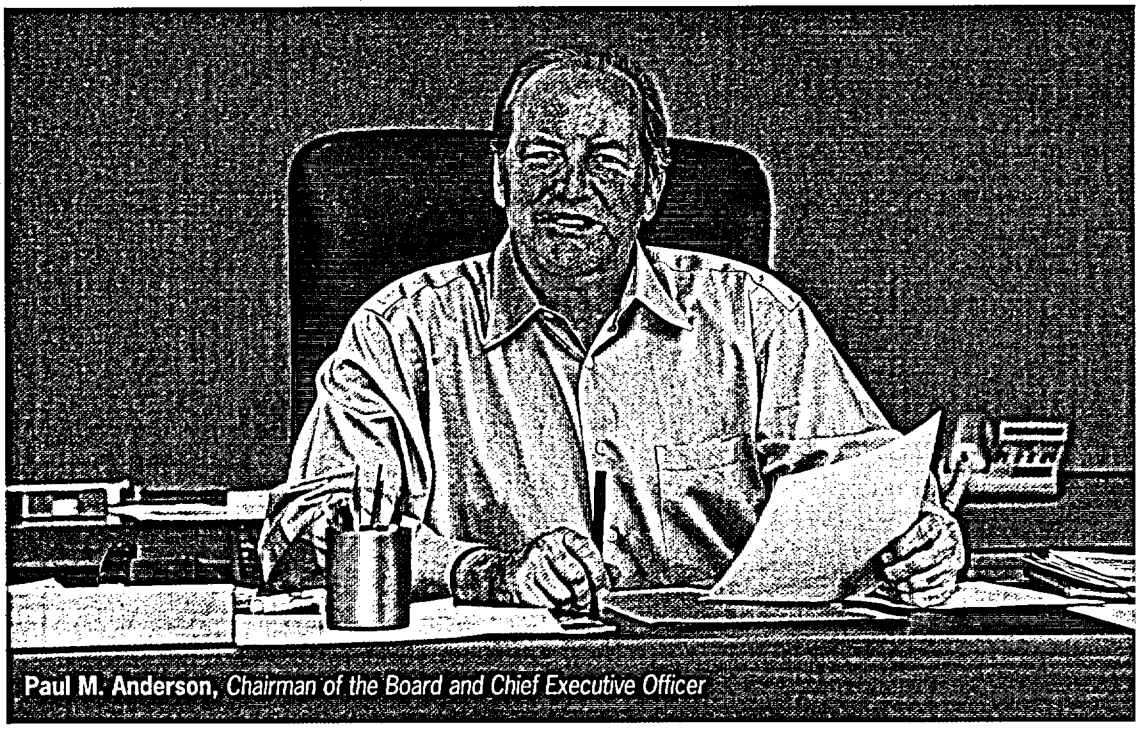
Resolve regulatory and legal issues — Mostly behind us

Shareholder return of 30% vs. 11% for S&P 500 — Not bad!

IN THIS REPORT

Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

This document contains forward-looking information which is subject to risks and uncertainties that could cause actual results to be different than those contemplated, including, but not limited to: changes in state, federal or international regulatory environments; commercial, industrial and residential growth in the company's service territory; the weather and other natural phenomena; the timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates; general economic conditions; changes in environmental and other laws and regulations to which Duke Energy and its subsidiaries are subject, or other external factors over which Duke Energy has no control; the results of financing efforts; the effect of accounting pronouncements; growth in opportunities for Duke Energy's business units; and other risks described in the company's 2004 SEC Form 10-K and other Securities and Exchange Commission filings. The company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.



Paul M. Anderson, *Chairman of the Board and Chief Executive Officer*

Dear Fellow Shareholder,

My letter to you last year focused on the challenges our company faced as we sought to redefine our position in an industry which was itself emerging from a painful restructuring. At that time, we were long on promises and resolve, but rather short on results. We had assessed our situation, implemented some organizational changes, articulated an investment proposition and developed a charter for the company.

The charter listed five imperatives which formed the basis for a number of specific objectives for 2004. Assessing our performance against those objectives gives me a sense of accomplishment – even cautious pride – which is tempered by deep disappointment over where we have failed. We also have some unfinished business to address.

Our Accomplishments

In January 2004, we detailed a financial plan for our investors. At that time, many in the financial community were skeptical as to our ability to achieve that plan, but we ended up significantly exceeding each of our commitments. We maintained the dividend of $1.10 per share, beat our ongoing basic earnings-per-share goal of $1.20 by 18 cents, reduced debt by $4.6 billion (lowering debt as a percent of total capital to 51 percent from 58 percent), maintained liquidity well over $1 billion and voluntarily contributed more than $500 million to our U.S. pension plan and nuclear decommissioning funds.

We were also able to significantly reduce DENA's (Duke Energy North America's) mark-to-market exposure and close out a number of legal and regulatory uncertainties that the company was facing. As a result, our credit rating stabilized, and the market also responded positively, as our share price rose by 25 percent to close the year at $25.33. We delivered a total return to shareholders of 30 percent for 2004 – outpacing the S&P 500's 11 percent.

Much of our financial plan was achieved by aggressively realigning our portfolio. We realized over $3.1 billion of proceeds from the sale of assets, such as our merchant plants in the southeast United States, our asset portfolios in the Asia-Pacific region and Europe, and two of our three deferred plants. (The sale of the third plant is expected to close in March 2005.)

FINANCIAL HIGHLIGHTS

(In millions, except per-share amounts)	Years Ended December 31 2004	2003[b]	2002	2001	2000
Statement of Operations					
Operating revenues	**$ 22,503**	$ 22,080	$ 15,860	$ 17,889	$ 15,800
Operating expenses	**19,456**	22,818	13,258	14,311	12,775
Gains on sales of investments in commercial and multi-family real estate	**192**	84	106	106	75
(Losses) gains on sales of other assets, net	**(225)**	(199)	32	238	214
Operating income (loss)	**3,014**	(853)	2,740	3,922	3,314
Other income and expenses, net	**302**	584	379	311	707
Interest expense	**1,349**	1,380	1,097	760	887
Minority interest expense	**195**	61	116	326	302
Earnings (loss) from continuing operations before income taxes	**1,772**	(1,710)	1,906	3,147	2,832
Income tax expense (benefit) from continuing operations	**540**	(707)	611	1,149	1,032
Income (loss) from continuing operations	**1,232**	(1,003)	1,295	1,998	1,800
Income (loss) from discontinued operations, net of tax	**258**	(158)	(261)	(4)	(24)
Income (loss) before cumulative effect of change in accounting principle	**1,490**	(1,161)	1,034	1,994	1,776
Cumulative effect of change in accounting principle, net of tax and minority interest	**—**	(162)	—	(96)	—
Net income (loss)	**1,490**	(1,323)	1,034	1,898	1,776
Dividends and premiums on redemption of preferred and preference stock	**9**	15	13	14	19
Earnings (loss) available for common stockholders	**$ 1,481**	$ (1,338)	$ 1,021	$ 1,884	$ 1,757
Ratio of Earnings to Fixed Charges	**2.3**	—[c]	2.2	3.9	3.7
Common Stock Data[a]					
Shares of common stock outstanding					
Year-end	**957**	911	895	777	739
Weighted average	**931**	903	836	767	736
Earnings (loss) per share (from continuing operations)					
Basic	**$ 1.31**	$ (1.13)	$ 1.53	$ 2.59	$ 2.42
Diluted	**1.27**	(1.13)	1.53	2.57	2.41
Earnings (loss) per share (from discontinued operations)					
Basic	**$ 0.28**	$ (0.17)	$ (0.31)	$ (0.01)	$ (0.03)
Diluted	**0.27**	(0.17)	(0.31)	(0.01)	(0.03)
Earnings (loss) per share (before cumulative effect of change in accounting principle)					
Basic	**$ 1.59**	$ (1.30)	$ 1.22	$ 2.58	$ 2.39
Diluted	**1.54**	(1.30)	1.22	2.56	2.38
Earnings (loss) per share					
Basic	**$ 1.59**	$ (1.48)	$ 1.22	$ 2.45	$ 2.39
Diluted	**1.54**	(1.48)	1.22	2.44	2.38
Dividends per share	**1.10**	1.10	1.10	1.10	1.10
Balance Sheet					
Total assets	**$ 55,470**	$ 57,225	$ 60,122	$ 49,624	$ 59,276
Long-term debt including capital leases, less current maturities	**$ 16,932**	$ 20,622	$ 20,221	$ 12,321	$ 10,717
Capitalization					
Common equity	**45%**	37%	36%	41%	37%
Preferred stock	**0%**	0%	1%	1%	1%
Trust preferred securities	**0%**	0%	3%	5%	5%
Total common equity and preferred securities	**45%**	37%	40%	47%	43%
Minority interests	**4%**	5%	5%	7%	9%
Total debt	**51%**	58%	55%	46%	48%

[a] Amounts prior to 2001 were restated to reflect the two-for-one common stock split effective January 26, 2001.
[b] As of January 1, 2003, Duke Energy adopted the remaining provisions of Emerging Issues Task Force Issue No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and for Contracts Involved in Energy Trading and Risk Management Activities" and Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations." In accordance with the transition guidance for these standards, Duke Energy recorded a net-of-tax and minority interest cumulative effect adjustment for change in accounting principles.
[c] Earnings were inadequate to cover fixed charges by $1,707 million for the year ended December 31, 2003.

In addition to generating funds, those sales repositioned Duke Energy as a company focused on the Americas and eliminated some of our lowest-return assets. We also challenged our real estate subsidiary, Crescent Resources, to become a major contributor of cash, and it responded with a stunning contribution of more than $440 million.

We moved into 2005 with a solid earnings base and the financial flexibility to once again control our own destiny. In February, we announced that we would buy back up to $2.5 billion in common stock over the next three years, based on our strong cash position. This share repurchase program will create value for shareholders, without inhibiting our ability to pursue future growth opportunities. We plan to pursue new growth cautiously, remaining mindful that we spent the year 2004 recovering from the effects of what in hindsight was an overly aggressive growth strategy.

Pride in the Organization

Given the significant achievements of the last 12 months, it is noteworthy that the members of the team that accomplished them were, with few exceptions, already here when I rejoined the company in November 2003. It is a tribute to that depth of talent that I was not forced to go outside the company to renew the organization. Using existing bench strength, we have significantly refreshed the organization and taken a number of steps to further develop the talent we have.

I am quite proud of the team we have in place today. Employees at all levels recognized the challenges that the company faced and stepped up to accept responsibility for resolving them. The company has done its part by aligning rewards with results, refocusing on talent management and reinvigorating a number of employee development programs. Particular attention has been focused on diversity, training, performance management and management development. During December 2004, the senior management team underwent a 360-degree evaluation, and a number of executive rotations were set in motion to ensure that we are developing the next generation of leadership at all levels.

Another source of pride was the contribution that Duke employees made to their communities. To commemorate Duke Power's 100th anniversary in 2004, our annual month-long Global Service Event was expanded to 100 days. An estimated 9,000 employees and retirees spent approximately 27,000 hours completing more than 500 service projects in the United States, Canada, Brazil and Peru.

Also in 2004, Duke Power proactively engaged leaders in business, industry, government, education and the nonprofit sector in economic development summits in North Carolina and South Carolina. In the Carolinas and elsewhere, Duke is actively involved in the communities in which we operate.

We also made progress in increasing our focus on customers and working with regulators to achieve win-win outcomes. For example, regulators in the Carolinas embraced an innovative approach where we share profits from Duke Power's bulk power marketing sales with our customers. Those dollars are funding job retraining programs and providing energy assistance to low-income households – improving the quality of life in our region. In North Carolina, some of these funds are also being used to reduce industrial rates, allowing those customers to offer more cost-competitive products and services.

We began a process of renewal at the Board level, beginning with an in-depth assessment led by an independent third party. As a result, we established a lead director, formed a Nuclear Oversight Committee, rotated committee heads and welcomed two new Board members, Roger Agnelli and Dennis Hendrix. We thank Bob Brown, George Dean Johnson and Leo Linbeck for their many contributions over the years; they will be retiring from the Board in May 2005.

Disappointments

While we are proud of our successes, we cannot ignore our failures. The biggest disappointment of 2004 was our unacceptable safety record. A number of measures can be used to judge an organization's safety record, but none is so personal or powerful as the number of employee and contractor fatalities. In 2004, one employee and three contractors lost their lives while working for Duke Energy. This is more than unacceptable – it is a tragedy for which I feel personally responsible. I would like to rationalize why those fatalities occurred, but I simply cannot. Safety is not something that can be prescribed or controlled through process alone. It relies on a culture that is nurtured from the top, and Duke's top management cannot allow safety to be overshadowed by other priorities.

Another disappointment was the fire last August at our Moss Bluff natural gas storage facility near Houston. Thankfully, no employee or contractor was injured, yet it is disappointing that such an incident could occur.

We have taken a number of steps to improve our safety focus. Later on in this report, Fred Fowler will address some of them. For my part, I will not feel that we have had a truly successful year unless that year is free of fatalities and major operational incidents.

Unfinished Business

We made significant progress in a number of areas, but we are left with unfinished business. Developing a sustainable business model for DENA is one such area. We made substantial progress in restructuring DENA and expect it will cut its losses by nearly half in 2005, but it may take a combination with one or more other parties, including other merchant generators, to provide the scope, scale and fuel diversity needed to realize an acceptable return on that investment.

A tremendous effort and significant funds were expended to comply with Sarbanes-Oxley Section 404, which mandates a thorough self-assessment of our internal controls over financial reporting. Despite the frustration of a rigid process and a challenging time frame, the effort proved very beneficial in helping us understand where we could improve our processes and systems. In 2005, we will build on what we have learned and re-engineer our financial systems, simplify our organization and reduce bureaucracy. Ultimately, this effort should greatly reduce our overhead costs in future years.

Looking Forward

As we enter 2005 and beyond, I am optimistic. The management objectives in our 2005 charter reflect the progress we made in 2004 to reclaim control of our future. This year, we are pursuing growth opportunities and reasserting our role as an industry leader.

The financial objective for 2005 is to ***deliver on our financial plan and provide superior total shareholder return.*** This reflects how far we have come – 2004's financial goal was to defend the dividend. We had an ongoing basic earnings-per-share target of $1.20 for employee incentive payouts in 2004. For 2005, we have increased that target by 33 percent to ongoing basic earnings per share of $1.60.

Another management objective is to ***establish industry-leading positions in core businesses and identify new energy-related growth strategies.*** We are in a position to grow any of our existing businesses if we find the right opportunity, and we will evaluate new but related lines of business to fuel future growth.

One 2005 objective relates to the unfinished business I discussed earlier: to ***position DENA to be a successful merchant operator with a sustainable business model.***

We will also ***enhance a high-performance culture by focusing on safety, inclusion and diversity, employee development, business structure and process simplification.*** The highest priority here is to improve our safety culture. We have created a shared safety goal for 2005 for the top 700 leaders in the company. If any Duke employee, contractor or subcontractor loses his or her life while doing work for us, this group will have their total short-term incentive payout reduced.

Our final objective for 2005 is to ***build stakeholder relationships and future shareholder value through effective leadership on key policy issues related to energy, regulation and the environment.*** It is clear that the United States needs cohesive environmental and energy policies that break the continuing logjam, and we intend to take a leadership role in developing and advancing those policies. For example, we will be proactive on the issue of global climate change. By helping shape public policy, we can advance the interests of our investors and customers, while also addressing the issue itself. Ideally, U.S. public policy should encourage a transition to a lower-carbon-intensive economy through a broad-based approach, such as a carbon tax or other mechanism which addresses all sectors of the economy.

As I close this letter, I would be remiss if I did not address the most critical concern I wrote of last year: restoring credibility with our key constituents. In 2004, I believe we made significant progress in re-earning their trust. While trust and credibility are hard to measure, we see positive indicators – in the tone and tenor of questions from our many stakeholders, in the spirit and resilience of our employees, and in the contracts and handshakes with our partners and customers. As I said last year, the task of building confidence will always be unfinished business for us, but I hope that you share my sense of real progress in this area and a positive view of our company's future.

I appreciate your many comments and suggestions over the past year and thank you for your continued investment in Duke Energy.

Sincerely,

Paul Anderson

Paul M. Anderson
Chairman of the Board and Chief Executive Officer

March 15, 2005

OUR 2005 CHARTER

We are Duke Energy, a leading energy company located in the Americas with an affiliated real estate operation.

Our purpose is to create superior value for our customers, employees, communities and investors through the production, conversion, delivery and sale of energy and energy services.

To provide a stable platform for future growth, we must:

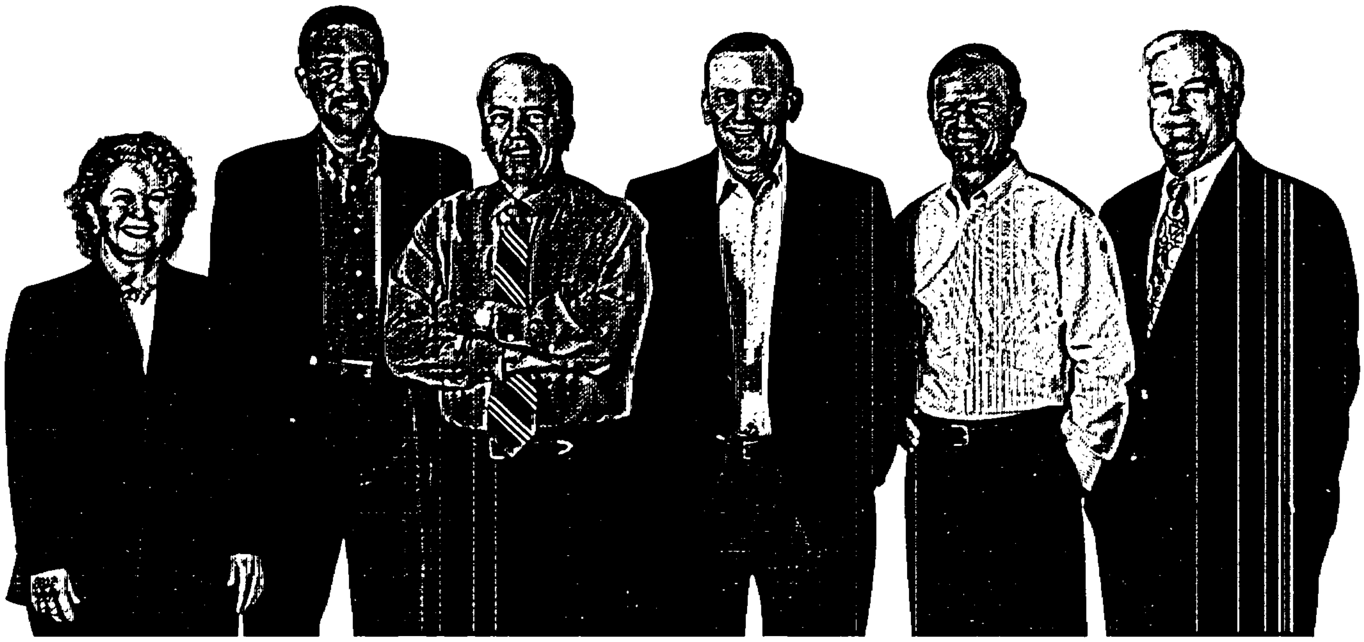
- Enhance a high-performance culture by focusing on safety, inclusion and diversity, employee development, business structure and process simplification.
- Position DENA to be a successful merchant operator with a sustainable business model.
- Deliver on our financial plan and provide superior total shareholder return.
- Establish industry-leading positions in core businesses and identify new energy-related growth strategies.
- Build stakeholder relationships and future shareholder value through effective leadership on key policy issues related to energy, regulation and the environment.

In conducting our business, we value:

- Stewardship – A commitment to health, safety, environmental responsibility and our communities.
- Integrity – Ethically and honestly doing what we say we will do.
- Respect for the Individual – Embracing diversity and inclusion, enhanced by openness, sharing, trust, teamwork and involvement.
- High Performance – The excitement and fulfillment of achieving superior business results and stretching our capabilities.
- Win-Win Relationships – Having relationships which focus on the creation of value for all parties.
- Initiative – Having the courage, creativity and discipline to lead change and shape the future.

We will be successful when:

- Our investors realize a superior return on their investment.
- Our customers and suppliers benefit from our business relationships.
- The communities in which we operate value our citizenship.
- Every employee starts each day with a sense of purpose, and ends each day with a sense of accomplishment.



Dear Shareholders,

Overall, 2004 was a year of considerable progress in Duke Energy's operations. I welcome this opportunity to report on those results, and review some of the past year's successes and disappointments.

Duke Energy's diverse portfolio allows us to balance the market risk in our nonregulated businesses with the relatively stable earnings that our regulated companies provide.

Regulated Businesses Generated Steady Earnings

Duke Power contributed $1.47 billion in segment earnings before interest and taxes (EBIT) in 2004. The utility provides us with a solid base of earnings and cash flow. Duke Power is working hard at diversifying its customer base and attracting new business to our area. Duke Power's customers pay essentially the same average rate per kilowatt-hour today as in 1986. At about 21 percent below the national average (due to efficient operations, cost management and lower-cost nuclear generation) those competitive rates offer an important advantage to customers in our service territory, and are especially attractive to potential new industries.

In 2004, Duke Energy Gas Transmission's (DEGT's) 17,500 miles of transmission pipeline continued to move natural gas to key distribution companies along the U.S. East Coast and in Canada, contributing $1.31 billion in segment EBIT. Expansion activity has been brisk over the past year, with infrastructure projects completed in western Canada and in the U.S. Northeast, Mid-Atlantic, Southeast and Gulf Coast regions. Transportation reliability was also strong, with DEGT operations in both the United States and Canada setting numerous all-time peak volume records. Reliability, combined with outstanding customer service, contributed to contract renewal levels of nearly 100 percent in our northeast U.S. market.

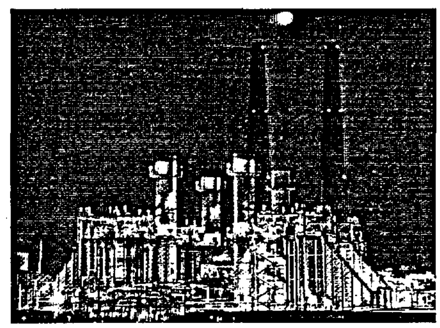
Weather – as it relates to heating and cooling needs – has a major impact on both DEGT and Duke Power, but the weather created a different challenge in 2004. For most of the southeastern United States, 2004 will be remembered as the year of the hurricanes. Several of our businesses experienced minor disruptions, but Duke Power's transmission and distribution system was

2004 operations leadership (above, left to right): Ruth Shaw, Duke Power; Bill Easter, Duke Energy Field Services; Fred Fowler, President and Chief Operating Officer, Duke Energy; Bobby Evans, Duke Energy Americas; Tom O'Connor, Duke Energy Gas Transmission; Art Fields, Crescent Resources largely spared from effects of the hurricanes. That allowed our line crews to provide needed support to utility customers in Florida and throughout the Southeast.

Unregulated Businesses Saw Challenges and Opportunities

Paul provided an overview of our progress with Duke Energy Americas, which includes Duke Energy North America (DENA) and Duke Energy International (DEI). Those businesses ended 2004 with very different scale and scope than when they began. The sale of DEI's Asia-Pacific assets allows us to focus on our operations in Latin America. In 2004, DEI generated segment EBIT from continuing operations of $222 million and is looking for a 2 to 3 percent compound annual growth rate over the next three years, based on its 2004 ongoing segment EBIT of $236 million.

While unfinished business remains for DENA in 2005, we should not overlook the significant progress made in 2004. We sold our generating portfolio in the Southeast as well as two deferred plants in the West – and expect to close on the sale of a third in March 2005. We also changed the DENA business model to focus on contracting a larger share of electric generation through tolls and capacity sales. (Tolls are agreements to sell all or part of a plant's capacity or production for a fee.) We are now beginning to see the benefits of that approach. For example, in 2004 DENA sold more than 50 major tolls and future capacity contracts to investor-owned utilities, municipalities and other customers, adding significantly to DENA revenue for 2005 and beyond. Additionally, DENA reduced operating expenses by nearly $180 million. We expect to cut DENA's $288 million ongoing segment EBIT loss from continuing operations in 2004 roughly in half, to a projected ongoing EBIT loss of approximately $150 million in 2005. We continue to pursue various options that will create a sustainable business model for DENA, including consideration of potential business partners.



Duke Energy North America's Moss Landing facility in California is one of the largest and most efficient generating plants in the state. (Photo: David Sievert)

While market conditions have challenged DENA, they have provided opportunities for our other businesses. Record-high crude oil prices meant a blockbuster year for Duke Energy Field Services (DEFS), generating EBIT from continuing operations of $380 million to Duke Energy. DEFS is the largest processor of natural gas liquids (NGLs) in the United States, and NGL prices roughly track the price of crude oil. But it is not only the price of crude that is helping DEFS. Even in a record-breaking year, DEFS initiated business improvements that reduced costs for its ongoing operations by $30 million.

In February 2005, we reached agreement with ConocoPhillips to restructure our 70 percent ownership of DEFS into an equal partnership, which will reduce our exposure to commodity price risk and provide more than $500 million in pre-tax cash to Duke Energy. The deal will also transfer DEFS' natural gas gathering and processing facilities and ConocoPhillips' natural gas liquids system in western Canada to DEGT – adding significantly to the scope, scale and diversity of DEGT's Canadian operations.

Crescent Resources, our real estate and land management subsidiary, concentrated on the strongest segments of the U.S. real estate market in 2004, generating record results of $240 million in segment EBIT from continuing operations. While Crescent regularly refreshes its property holdings, 2004 results reflected an opportunistic sale of property in the Washington, D.C. area. Going forward, we expect Crescent's segment EBIT contribution to return to a more historic level of approximately $150 million in 2005.

Legal Issues Resolved

We made tremendous progress in 2004 in resolving many of the company's regulatory and legal risks. Most significantly, a comprehensive settlement with western U.S. power market participants, approved by the Federal Energy Regulatory Commission in December, provided needed closure to issues that arose in that market in 2000 and 2001. We were also gratified that the U.S. Attorney closed an investigation into Duke Power's 1998 to 2000 accounting practices, concluding that no action was warranted against the company or its employees.

Safety Performance Must Improve

Regarding safety, I can only say that our performance in 2004 was, in a word, unacceptable. Four people who came to work at Duke Energy facilities last year did not go home to their families. In response, we are building a zero-injury safety culture to prevent employee and contractor injuries.

- We have communicated a new safety vision to all employees that aims for zero injuries through continuous safety improvement, and we are setting the same expectations for our contractors.
- We are leading this culture change from the top – every member of the Expanded Executive Committee has personal safety objectives that spell out exactly how they will lead their organization to an improved safety record.
- I will discuss in person our safety expectations with more than 2,500 managers and supervisors in 2005.
- Business units are conducting employee safety perception surveys, and I will personally review the safety improvement plans developed in response to those surveys.

Hector Gutierrez and Pilar Dávila of Duke Energy Peru's Lima office brighten the educational experience for local elementary students with a fresh coat of paint for their desks.

We Gave Back to Our Communities

To customers and communities, our employees are the face of Duke Energy. Corporate giving and volunteerism remain hallmarks of Duke Energy, and in 2004 we continued to make a real difference in our communities in the following ways:

- Duke Energy marks its birthday each year with a Global Service Event. In 2004, thousands of employees and retirees participated in more than 500 volunteer projects in 170 communities where Duke Energy operates. Most of the projects helped improve the lives of children, senior citizens and disabled individuals. In Peru, for example, employees focused on children and education. They donated books and school supplies, painted classrooms, served lunch and organized activities.
- Duke Energy employees were recognized with Ethics in Action's Community Care Award for developing innovative community partnerships and programs serving the residents of British Columbia.
- In the Carolinas, we are leading economic development efforts to diversify our region's economy and provide opportunities for growth. That's good for Duke Power and good for the region. In 2004, Duke Power contracted more than $23.3 million of new annual electric load (compared to $6.2 million for 2003), and nearly 200 additional projects are pending.
- Crescent Resources won accolades from community leaders and state officials for committing to sell nearly 3,000 acres and to make a one-time multi-million-dollar gift to the state of North Carolina to expand Lake James State Park almost sixfold.
- The Texas Corporate Wetlands Restoration Partnership, led by DEGT employees, participated in one of only 12 projects honored nationwide by Coastal America – a partnership of federal agencies and state and local private organizations. Our work on the San Jacinto battleground project near Houston contributed to the restoration of 115 acres of historic marshland as well as adjacent prairie and bottomland forest.

These are just a few examples of the many ways the people of Duke Energy work to improve our communities, economy and environment. On the following pages, the leaders of our businesses will tell you more about their performance and future objectives.

Sincerely,

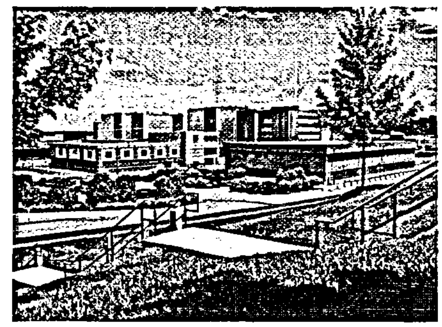
Fred J. Fowler

President and Chief Operating Officer

BEGINNING A SECOND CENTURY OF SERVICE

In 2004, Duke Power celebrated its 100th anniversary in a way that honored our heritage – by taking a leading role in advancing economic development in the Carolinas.

In recent years, textiles and other industries that were once the bedrock of the region's economy have steadily declined. Our competitive electric rates are one way to attract new business. But energy costs are just one aspect of a region's commercial appeal. Much like our founders, who used electricity to help drive the textile boom early in the 20th century, we are working to strengthen and diversify our economy and expand our customer base by attracting new business and industry to our service territory.



Catawba Nuclear Station in York County, S.C., set a new Duke Power reliability record in 2004, and was recognized by the U.S. Nuclear Regulatory Commission for safe operations.

Major accomplishments:

✓ Duke Power jump-started the economic development engine by bringing more than 500 business, industry, government, nonprofit and academic leaders together for two Carolinas Competitiveness Forums in 2004.

✓ We are already seeing results from our push to help recruit and retain manufacturing. Major companies like Merck and Dell, and many smaller businesses, have announced plans to locate facilities in Duke Power's service territory.

✓ Regulators embraced our plan to share some of the profits from our bulk power marketing sales 50-50 with shareholders and customers. Programs funded by these sharing arrangements help pay energy bills for low-income residents, fund workforce training at community colleges, help reduce industrial rates in North Carolina, and support energy-efficient industrial improvements and local economic development initiatives in South Carolina.

✓ Duke Power's generating fleet continues to excel in reliability and efficiency. Catawba Nuclear Station set a new company reliability record in September, operating for 531 continuous days, and Electric Light & Power magazine named Marshall Steam Station the most efficient coal-fired station in the United States.

No amount of business achievement can make up for the tragic loss of three of our contractors in 2004. Ensuring the safety of employees, contractors and customers remains a core Duke Power value, and we are focused intently on both the cultural and process changes needed to reduce avoidable accidents, injury and risk.

Looking ahead, our growth forecasts indicate a need for new base-load generation within the next decade. We are evaluating options to meet that need in ways that are both economical and environmentally sound. We are upgrading a number of our existing coal-fired stations with state-of-the-art environmental equipment, and evaluating emerging clean-coal technologies. The relicensing of our hydroelectric facilities, currently underway, will ensure the continuation of hydropower as an economical and emission-free energy resource, while preserving water quality and recreational access. And to secure the option of future nuclear generation capacity, we are in the initial stages of preparing a combined construction and operating license application for a new, advanced-design nuclear plant.

As Duke Power enters its second century, we continue to build on the fundamentals of customer service, operational performance, safety, responsible citizenship and innovation.

— **Ruth Shaw,** *President and Chief Executive Officer, Duke Power*

Profile: One of the largest investor-owned electric utilities in the United States, Duke Power delivers safe, reliable and economically priced electricity to more than 2 million customers in North Carolina and South Carolina.

Operating Data	**2004**	2003	2002	2001	2000
Franchised Electric					
Sales, gigawatt-hours	**82,708**	82,828	83,783	79,685	84,766
Nuclear capacity factor[a]	**90%**	91%	95%	92%	92%
Average number of customers	**2,197,000**	2,160,000	2,117,000	2,117,000	2,072,000

[a] Includes 100 percent of Catawba Nuclear Station, which is 12.5 percent owned by Duke Power.

REFOCUS ON GROWTH

Duke Energy Gas Transmission (DEGT) pipelines are strategically located with access to diverse supply basins and growing markets throughout North America, and our storage facilities offer customers reliability and seasonal flexibility.

We expect demand for natural gas to grow by an average 2 to 3 percent annually in our key markets over the next five years. Our challenge is to keep pace with that demand, by developing the infrastructure needed to connect new supplies to growing markets.

Major accomplishments:

✓ Three natural gas pipeline and two gas storage expansion projects began to serve DEGT customers in 2004, adding delivery capacity for customers in the U.S. Northeast, Southeast and Mid-Atlantic states. Storage facility expansions in Louisiana and Virginia increased available gas storage capacity by 1.8 billion cubic feet.

✓ The 110-mile extension of the Gulfstream pipeline from central Florida to the state's east coast was completed in February 2005, doubling the pipeline's firm contracted capacity. (Gulfstream is a joint development of Duke Energy and Williams.)

✓ Multiple peak-volume days on our Texas Eastern, Algonquin, East Tennessee, Gulfstream and Union Gas systems demonstrated our ability to operate reliably and provide access to growing markets.

✓ In August, DEGT employees mobilized quickly and effectively in response to a fire at our Moss Bluff gas storage facility near Houston. We regret that this incident occurred and the inconvenience that it caused our neighbors and customers.

✓ A successful "open season" in the northeast United States and eastern Canada signaled strong customer demand for new natural gas transportation and storage solutions. Many of those responses should result in new contracts and several expansion projects over the next three to five years.

✓ Union Gas added more than 31,000 new customers in 2004 through focused marketing efforts and reliable service.

✓ Rate proceedings involving our BC Pipeline and Union Gas businesses were resolved fairly for both customers and shareholders.

Plant operator Charles Barker monitors storage operations at the Kingsport liquefied natural gas storage facility, on DEGT's East Tennessee Natural Gas pipeline system.

Over the next several years, we plan to invest more than $1 billion in DEGT facility expansions. We expect liquefied natural gas (LNG) to play a major role in North America's future natural gas supply. LNG import terminals are proposed along the Gulf Coast and the northern East Coast, including the Canadian Maritimes, and most of them would have ready access to Duke Energy's existing pipelines and storage facilities. We intend to be a major player in providing the pipeline expansion and storage needed to connect this new supply to growth markets.

Our assets are equally well-positioned in the growing Western Canadian Sedimentary Basin, and the addition of ConocoPhillips' natural gas liquids operations and DEFS' gathering and processing facilities to our system in 2005 will enhance that position. We are ready and willing to expand further, as natural gas drilling activity increases in northeastern British Columbia.

As I move on to pursue new career opportunities at Duke Energy, I am confident about the continued success of the business that Martha Wyrsch will now lead.

— **Tom O'Connor,** *President and Chief Executive Officer, Duke Energy Gas Transmission*

Profile: Duke Energy Gas Transmission serves its customers by transporting natural gas from North America's major supply areas to growing markets in the northeastern and southeastern United States and in Canada. DEGT also stores natural gas, distributes natural gas to retail customers in Ontario, and gathers and processes natural gas for customers in western Canada.

Operating Data	**2004**	2003	2002	2001	2000
Natural Gas Transmission					
Throughput, trillion British thermal units (TBtu)[a]	**3,332**	3,362	3,160	1,781	1,771
Storage capacity, billion cubic feet	**258**	257	254	101	98

[a] Represents share of capacity owned by DEGT.

A YEAR OF RECORD RETURNS

Duke Energy Field Services (DEFS) captured enormous value from strong natural gas liquids (NGL) prices and gas processing margins in 2004. We also improved operating and commercial performance, and benefited from increased production and a strategic acquisition. The combination of these factors resulted in record earnings for the DEFS joint venture.

Major accomplishments:

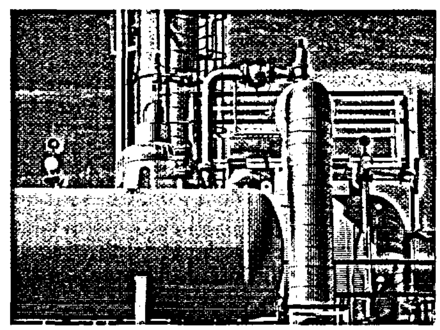
✓ We were able to handle higher natural gas volumes in many areas in 2004, due to increased drilling by our customers, with little or no additional investment. For example, we successfully processed and delivered almost 10 percent more gas on our Oklahoma "supersystem" by redistributing the flow of natural gas among the system's four plants.

✓ We delivered strong marketing results and continued to renegotiate natural gas supply contracts in order to better align our interests with those of producers, reduce earnings volatility and improve profitability.

✓ DEFS acquired natural gas gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips for $74 million. The acquisition included three processing plants and more than 1,000 miles of gathering pipeline. In addition to adding new customers and volumes, these assets, in combination with our existing facilities, improve market access and reliability for our customers.

✓ The number and severity of employee and contractor injuries declined at DEFS in 2004, as evidenced by a 40 percent reduction in safety-related lost workdays and more than a 50 percent reduction in contractor injuries versus 2003. Tragically, an employee of our former TEPPCO affiliate lost his life in a work-related accident, underscoring the importance of maintaining safety as our top priority.

✓ We successfully consolidated our computer operations into Duke Energy's computing center in Charlotte, eliminating our Denver data center and generating significant efficiency and cost improvements.


The Platteville facility is one of DEFS' newest gathering and processing plants, built to process increased natural gas production in the Denver-Julesburg Basin area of Colorado.

DEFS is poised to deliver another exceptional year of earnings in 2005. We expect commodity prices to remain above traditional levels, though perhaps somewhat lower than 2004.

In this, my second year at the helm at DEFS, we are working to further improve our underlying operational and commercial performance through continued application of best practices, by capturing efficiencies inherent in our large operating scale and scope, and by continually improving our processes and information systems.

Two 2005 transactions will allow us to focus on further strengthening our competitive position in the United States. As part of the pending restructuring of DEFS into a 50/50 joint venture with ConocoPhillips, we expect to receive additional U.S. midstream assets and our Canadian operations will move to DEGT. In addition, with the February 2005 sale of TEPPCO, our affiliated master limited partnership, we exited the business of transporting refined products and crude oil, as well as selected natural gas and NGL activities. Going forward, we will invest to improve the capability of our existing assets and pursue selective growth opportunities. Given today's competitive landscape, we will also evaluate the merits of establishing another master limited partnership.

— **Bill Easter,** *Chairman, President and Chief Executive Officer, Duke Energy Field Services*

Profile: The largest producer of natural gas liquids in North America and one of the largest marketers, Duke Energy Field Services gathers, processes, transports, markets and stores natural gas and produces, transports and markets NGLs. DEFS is a joint venture of Duke Energy and ConocoPhillips.

Operating Data	**2004**	2003	2002	2001	2000
Field Services					
Natural gas gathered and processed/transported, TBtu/day	**7.3**	7.4	7.9	8.0	7.0
Natural gas liquids production, thousand barrels per day	**363**	353	379	384	343
Average natural gas price per million Btu	**$ 6.14**	$ 5.39	$ 3.22	$ 4.27	$ 3.89
Average natural gas liquids price per gallon	**$ 0.68**	$ 0.53	$ 0.38	$ 0.45	$ 0.53

REALIGNING OUR PORTFOLIO

Duke Energy North America – Reducing Merchant Risk

Our goal for DENA in 2004 was to stabilize the business. We accomplished that through asset sales and cost efficiencies, and by moving from a commodity trading model to a stronger focus on marketing energy to customers from our own assets. An anticipated $300 million ongoing segment EBIT loss came in at $288 million, including unanticipated mark-to-market losses of $25 million. A team of employees committed to controlling costs and optimizing resources made it possible to achieve our financial goal.

Major accomplishments:

✓ The sale of our fleet of eight merchant plants in the southeast United States came sooner than many predicted. Completed in August, the sale boosted Duke Energy's 2004 divestiture proceeds by approximately $975 million, including about $500 million in tax benefits and a note receivable of approximately $50 million.

✓ We sold two partially completed plants in 2004 (Luna in New Mexico and Moapa in Nevada), as well as surplus turbines and related equipment. Proceeds from those transactions totaled approximately $600 million, including about $270 million in tax benefits. At year-end, we signed an agreement to sell a third deferred-construction plant (Grays Harbor in Washington state).

✓ We mitigated our earnings volatility by significantly reducing the exposure to fluctuating commodity prices associated with our mark-to-market portfolio.

✓ DENA strengthened its position in long-term gas storage capacity, providing flexibility to fuel our own plants as well as serve other customers.

✓ Duke Energy's settlement of refund proceedings and other litigation related to the 2000-2001 western U.S. energy crisis cleared the way for some of the large utilities in those markets to return as DENA customers.

✓ DENA's Lee facility in Illinois added "black start" capability in 2004 that will allow the unit to start without any outside electrical supply. Even during a blackout, it can be brought into service to help ensure the stability and reliability of the electric grid in the Midwest.

✓ We made substantial progress on winding down the Duke Energy Trading and Marketing joint venture with ExxonMobil. By the end of 2004, we had completed or signed transactions to sell about 90 percent of that business.

Production technicians Mike Armstrong, Benny King and Steve Anderson ensure that the Washington Energy Facility in southeastern Ohio operates safely and reliably. The plant has had no recordable injuries since it opened in 2001.

Success at DENA is measured in relative terms. We are determined to reduce DENA's losses and return the business to profitability. We expect to cut our ongoing EBIT loss nearly in half in 2005, to approximately $150 million. By the end of 2006, on an ongoing basis, we anticipate breaking even, and we look forward to being profitable again in 2007.

We will continue to control costs and manage our portfolio with smart business decisions. We have strong assets in growing areas, and energy demand continues to grow. We intend to be a strong player in the merchant energy market.

As in the rest of Duke Energy, we are renewing our emphasis on safety. Many of our plants have perfect safety records. We are challenging ourselves to spread that zero-injury culture across our entire fleet.

Profile: Duke Energy North America owns and operates merchant power generation facilities, and markets electricity, natural gas, energy management and related services to wholesale customers throughout North America.

Operating Data	2004	2003	2002	2001	2000
Duke Energy North America					
Actual plant production, gigawatt-hours	**21,884**	24,046	24,962	20,516	18,523
Proportional capacity in operation, megawatts[a]	**9,890**	15,820	14,157	6,799	5,134

[a] Represents share of capacity owned by DENA.

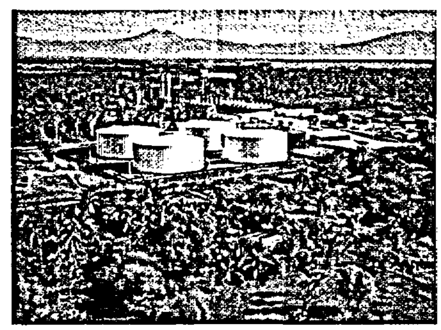
Duke Energy International – A Sharper Focus

Duke Energy International (DEI) began 2004 with a goal of exiting the European and Asia-Pacific markets – to focus on increasing the returns from our power generation business in Latin America. Energy demand in that part of the world is growing at 4 to 6 percent a year, two to three times the growth rate in North America, and DEI owns generation assets in seven Latin American countries.

DEI's continuing operations delivered solid results in 2004, contributing $222 million in EBIT toward Duke Energy's overall goals.

Major accomplishments:

- ✓ With the US$1.2 billion sale of our assets in Australia and New Zealand in April (including $840 million of debt assumed by the buyer), Duke Energy reached its 2004 divestiture target just four months into the year. In May, DEI sold its 30 percent equity interest in the Cantarell nitrogen facility in Mexico, and by year-end, our exit from Europe was largely complete.
- ✓ Planta Arizona in Guatemala completed its dual-fuel conversion, making it one of the most efficient thermal plants in Central America. By using a mix of different fuels, Duke Energy has become one of the lowest-cost energy providers in that region.
- ✓ In Brazil, a successful contracting strategy significantly reduced our exposure to low-price spot markets in 2004 and eliminated that exposure for 2005. At the same time, we are preserving capacity for 2006 and beyond, in anticipation of improving market conditions and price levels.
- ✓ DEI's overall safety record improved in 2004. DEI Brazil became the first company to earn the Eloy Chaves Medal, the most prestigious safety award in the country's electric power industry, for three consecutive years.
- ✓ Our employees in Brazil have worked for more than five years without a lost-time incident, and our Peru and Argentina facilities recently surpassed two years without a lost-time incident.
- ✓ Duke Energy Peru became the first company in Peru, and the first in the Duke Energy system, to obtain simultaneous international certifications for operations management, environmental management, and occupational health and safety practices, based on International Organization for Standardization (ISO) guidelines.



The 160-megawatt Planta Arizona in Guatemala generates electricity efficiently and at low cost, using dual-fuel technology.

DEI's operations are well-positioned to achieve higher earnings and returns in the near term, and to benefit from continued growth in energy demand in Latin America.

— **Bobby Evans,** *President and Chief Executive Officer, Duke Energy Americas*

Profile: Duke Energy International owns and operates power generation facilities, and sells electric power and natural gas. Its primary focus is on power generation activities in Latin America.

Operating Data	**2004**	2003	2002	2001	2000
International Energy					
Sales, gigawatt-hours	**17,776**	16,374	18,350	15,749	14,154
Proportional capacity in operation, megawatts[a]	**4,139**	4,121	3,917	3,968	3,768

[a] Represents share of capacity owned by DEI.

MEETING THE CHALLENGE

Our challenge in 2004 was to contribute $400 million in cash and $155 million in EBIT to Duke Energy. We hit those targets – and then some – thanks to continuing strong demand for investment-grade real estate. At the same time, we kept all of our platforms – commercial, residential and multi-family – growing and well-positioned for 2005 and beyond. We didn't hold a liquidation sale to meet 2004's financial goals. We executed our strategy, continued to invest in our base of assets and enhanced our development and land management practices, upholding our reputation as a "green" developer. Every segment of our business contributed to our success in 2004.

Major accomplishments:

✓ Crescent completed master planning for Potomac Yard, a 300-acre mixed-use site adjacent to Reagan National Airport, and sold most of the property to other developers in 2004. We retain ownership of two office buildings under construction, and the General Services Administration has leased 405,000 square feet of that space for the Environmental Protection Agency.

✓ In the residential market, Crescent reached its all-time record of more than $413 million in individual homesite sales.

✓ Property sales are brisk at Palmetto Bluff, an environmental preserve and residential community in South Carolina's lowcountry. A portion of every real estate transaction funds the Palmetto Bluff Conservancy, a nonprofit organization dedicated to natural resource protection on the property.

✓ We sold nearly 3,000 acres of lakefront property and made a one-time multi-million-dollar gift to the state of North Carolina to expand Lake James State Park. The sale, which closed in January, is a key component in a master plan to drive economic growth in the Lake James region and preserve the lake environment for wildlife and recreation.

✓ We're participating in the development of a major mixed-use development in Charlotte, N.C., that will include the new corporate headquarters for Piedmont Natural Gas.

The Auberge Inn at Crescent's Palmetto Bluff community in South Carolina opened in 2004, along with the Jack Nicklaus-designed May River golf course.

Most segments of the real estate market held strong in 2004, and Crescent is well-positioned for the future regardless of market conditions. We are investing primarily in the Southeast and the Southwest – growing regions with diverse economies. Studies show that 85 percent of growth in the United States is occurring in the coastal states, plus Arizona and Nevada.

Within this geographic area, we offer a diversified mix of high-growth product types, including second homes and retirement homes for baby boomers. We're broadening our reach into that market with more diverse real estate offerings, and branching out into residential condominiums, primarily in Florida. We'll continue to adjust our portfolio to invest in both residential and commercial growth markets.

It should be noted that 2004 was a banner year, and it's unrealistic to expect the same results on an annual basis. We can promise, however, to continue to capitalize on opportunities without taking undue risks, and to fulfill our commitments to Duke Energy and its investors.

— **Art Fields,** *President and Chief Executive Officer, Crescent Resources*

Profile: Crescent Resources manages land holdings and develops high-quality commercial, residential and multi-family real estate projects in nine states. Crescent Resources has received numerous awards for its environmentally sensitive property development strategies and partnerships with environmental and wildlife groups.

Operating Data	**2004**	2003	2002	2001	2000
Crescent Resources					
Residential lots sold	**2,473**	2,060	1,221	1,075	955
Commercial square footage sold, in millions	**2.1**	1.7	1.2	3.1	2.0
Multi-family units sold	**273**	950	—	—	—
Surplus (legacy) land sold, acres	**9,087**	5,088	10,982	11,402	8,562

	Years Ended December 31		
(In millions, except per-share amounts)	**2004**	2003	2002
Operating Revenues			
Non-regulated electric, natural gas, natural gas liquids and other	**$ 14,275**	$14,178	$ 8,780
Regulated electric	**5,111**	4,960	4,880
Regulated natural gas	**3,117**	2,942	2,200
Total operating revenues	**22,503**	22,080	15,860
Operating Expenses			
Natural gas and petroleum products purchased	**11,335**	11,419	5,360
Operation, maintenance and other	**3,568**	3,796	3,304
Fuel used in electric generation and purchased power	**2,098**	2,075	2,191
Depreciation and amortization	**1,851**	1,792	1,506
Property and other taxes	**539**	526	533
Impairment and other related charges	**65**	2,956	364
Impairments of goodwill	**—**	254	—
Total operating expenses	**19,456**	22,818	13,258
Gains on Sales of Investments in Commercial and Multi-Family Real Estate	**192**	84	106
(Losses) Gains on Sales of Other Assets, net	**(225)**	(199)	32
Operating Income (Loss)	**3,014**	(853)	2,740
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	**161**	123	218
(Losses) Gains on sales and impairments of equity investments	**(4)**	279	32
Other income and expenses, net	**145**	182	129
Total other income and expenses	**302**	584	379
Interest Expense	**1,349**	1,380	1,097
Minority Interest Expense	**195**	61	116
Earnings (Loss) from Continuing Operations Before Income Taxes	**1,772**	(1,710)	1,906
Income Tax Expense (Benefit) from Continuing Operations	**540**	(707)	611
Income (Loss) from Continuing Operations	**1,232**	(1,003)	1,295
Discontinued Operations			
Net operating loss, net of tax	**(10)**	(27)	(261)
Net gain (loss) on dispositions, net of tax	**268**	(131)	—
Income (Loss) from Discontinued Operations	**258**	(158)	(261)
Income (Loss) Before Cumulative Effect of Change in Accounting Principle	**1,490**	(1,161)	1,034
Cumulative Effect of Change in Accounting Principle, net of tax and minority interest	**—**	(162)	—
Net Income (Loss)	**1,490**	(1,323)	1,034
Dividends and Premiums on Redemption of Preferred and Preference Stock	**9**	15	13
Earnings (Loss) Available for Common Stockholders	**$ 1,481**	$ (1,338)	$ 1,021
Common Stock Data			
Weighted-average shares outstanding	**931**	903	836
Earnings (Loss) per share (from continuing operations)			
Basic	**$ 1.31**	$ (1.13)	$ 1.53
Diluted	**$ 1.27**	$ (1.13)	$ 1.53
Earnings (Loss) per share (from discontinued operations)			
Basic	**$ 0.28**	$ (0.17)	$ (0.31)
Diluted	**$ 0.27**	$ (0.17)	$ (0.31)
Earnings (Loss) per share (before cumulative effect of change in accounting principle)			
Basic	**$ 1.59**	$ (1.30)	$ 1.22
Diluted	**$ 1.54**	$ (1.30)	$ 1.22
Earnings (Loss) per share			
Basic	**$ 1.59**	$ (1.48)	$ 1.22
Diluted	**$ 1.54**	$ (1.48)	$ 1.22
Dividends per share	**$ 1.10**	$ 1.10	$ 1.10

CONSOLIDATED BALANCE SHEETS

	December 31	
(In millions)	**2004**	2003
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 533**	$ 397
Short-term investments	**1,319**	763
Receivables (net of allowance for doubtful accounts of $276 at 2004 and $280 at 2003)	**3,237**	2,953
Inventory	**942**	941
Assets held for sale	**40**	361
Unrealized gains on mark-to-market and hedging transactions	**962**	1,566
Other	**938**	694
Total current assets	**7,971**	7,675
Investments and Other Assets		
Investments in unconsolidated affiliates	**1,292**	1,398
Nuclear decommissioning trust funds	**1,374**	925
Goodwill	**4,148**	3,962
Notes receivable	**232**	260
Unrealized gains on mark-to-market and hedging transactions	**1,379**	1,857
Assets held for sale	**84**	1,444
Investments in residential, commercial and multi-family real estate (net of accumulated depreciation of $15 and $32 at December 31, 2004 and 2003, respectively)	**1,128**	1,353
Other	**1,896**	2,137
Total investments and other assets	**11,533**	13,336
Property, Plant and Equipment		
Cost	**46,806**	45,987
Less accumulated depreciation and amortization	**13,300**	12,139
Net property, plant and equipment	**33,506**	33,848
Regulatory Assets and Deferred Debits		
Deferred debt expense	**297**	275
Regulatory assets related to income taxes	**1,269**	1,152
Other	**894**	939
Total regulatory assets and deferred debits	**2,460**	2,366
Total Assets	**$ 55,470**	$ 57,225

(In millions)	December 31 2004	2003
LIABILITIES AND COMMON STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	**$ 2,414**	$ 2,317
Notes payable and commercial paper	**68**	130
Taxes accrued	**273**	14
Interest accrued	**287**	304
Liabilities associated with assets held for sale	**30**	651
Current maturities of long-term debt	**1,832**	1,200
Unrealized losses on mark-to-market and hedging transactions	**819**	1,283
Other	**1,815**	1,849
Total current liabilities	**7,538**	7,748
Long-term Debt, including debt to affiliates of $876 at 2003	**16,932**	20,622
Deferred Credits and Other Liabilities		
Deferred income taxes	**5,228**	4,120
Investment tax credit	**154**	165
Unrealized losses on mark-to-market and hedging transactions	**971**	1,754
Liabilities associated with assets held for sale	**14**	737
Asset retirement obligations	**1,926**	1,707
Other	**4,646**	4,789
Total deferred credits and other liabilities	**12,939**	13,272
Commitments and Contingencies		
Minority Interests	**1,486**	1,701
Preferred and Preference Stock without Sinking Fund Requirements	**134**	134
Common Stockholders' Equity		
Common stock, no par, 2 billion shares authorized; 957 million and 911 million shares outstanding at December 31, 2004 and 2003, respectively	**11,252**	9,519
Retained earnings	**4,539**	4,060
Accumulated other comprehensive income	**650**	169
Total common stockholders' equity	**16,441**	13,748
Total Liabilities and Common Stockholders' Equity	**$ 55,470**	$ 57,225

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	Years Ended December 31 2004	2003	2002
Cash Flows from Operating Activities			
Net income (loss)	**$ 1,490**	$ (1,323)	$ 1,034
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization (including amortization of nuclear fuel)	**2,037**	1,987	1,692
Cumulative effect of change in accounting principle	**—**	162	—
Gains on sales of investments in commercial and multi-family real estate	**(201)**	(103)	(106)
Gains on sales of equity investments and other assets	**(193)**	(86)	(81)
Impairment charges	**194**	3,495	545
Deferred income taxes	**867**	(534)	495
Purchased capacity levelization	**92**	194	175
Contribution to company-sponsored pension plans	**(278)**	(192)	(9)
(Increase) decrease in			
Net realized and unrealized mark-to-market and hedging transactions	**216**	(15)	596
Receivables	**(188)**	1,126	12
Inventory	**(48)**	(30)	134
Other current assets	**(35)**	(77)	(335)
Increase (decrease) in			
Accounts payable	**(5)**	(1,047)	798
Taxes accrued	**188**	(168)	(332)
Other current liabilities	**116**	79	(194)
Capital expenditures for residential real estate	**(322)**	(196)	(179)
Cost of residential real estate sold	**268**	167	117
Other, assets	**(305)**	(249)	205
Other, liabilities	**246**	206	(368)
Net cash provided by operating activities	**4,139**	3,396	4,199
Cash Flows from Investing Activities			
Capital expenditures, net of refund	**(2,055)**	(2,242)	(4,745)
Investment expenditures	**(46)**	(153)	(584)
Acquisition of Westcoast Energy Inc., net of cash acquired	**—**	—	(1,707)
Purchases of available-for-sale securities	**(64,594)**	(40,032)	(12,393)
Proceeds from sales and maturities of available-for-sale securities	**64,092**	39,641	11,859
Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable	**1,542**	1,966	516
Proceeds from the sales of commercial and multi-family real estate	**606**	314	169
Other	**(309)**	(162)	(69)
Net cash used in investing activities	**(764)**	(668)	(6,954)
Cash Flows from Financing Activities			
Proceeds from the:			
Issuance of long-term debt	**153**	3,009	5,114
Issuance of common stock and common stock related to employee benefit plans	**1,704**	277	1,323
Payments for the redemption of:			
Long-term debt	**(3,646)**	(2,849)	(1,837)
Preferred stock of a subsidiary	**(176)**	(38)	—
Preferred and preference stock	**—**	—	(88)
Guaranteed preferred beneficial interests in subordinated notes	**—**	(250)	—
Notes payable and commercial paper	**(67)**	(1,702)	(1,067)
Distributions to minority interests	**(1,477)**	(2,508)	(2,260)
Contributions from minority interests	**1,277**	2,432	2,535
Dividends paid	**(1,065)**	(1,051)	(938)
Other	**19**	23	64
Net cash (used in) provided by financing activities	**(3,278)**	(2,657)	2,846
Changes in cash and cash equivalents associated with assets held for sale	**39**	(55)	—
Net increase in cash and cash equivalents	**136**	16	91
Cash and cash equivalents at beginning of year	**397**	381	290
Cash and cash equivalents at end of year	**$ 533**	$ 397	$ 381
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	**$ 1,323**	$ 1,324	$ 1,011
Cash (refunded) paid for income taxes	**$ (339)**	$ (18)	$ 344
Significant non-cash transactions:			
Debt retired in connection with disposition of businesses	**$ 840**	$ 387	$ —
Note receivable from sale of southeast plants	**$ 48**	$ —	$ —
Remarketing of senior notes	**$ 1,625**	$ —	$ —
Acquisition of Westcoast Energy Inc.			
Fair value of assets acquired	**$ —**	$ —	$ 9,254
Liabilities assumed, including debt and minority interests	**—**	—	8,047
Issuance of common stock	**—**	—	1,702
Capital lease obligations related to property, plant and equipment	**$ —**	$ —	$ 117

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

(In millions)	Common Stock Shares	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss): Foreign Currency Adjustments	Net Gains (Losses) on Cash Flow Hedges	Minimum Pension Liability Adjustment	Total
Balance December 31, 2001	**777**	**$ 6,217**	**$ 6,292**	**$ (307)**	**$ 487**	**$ —**	**$12,689**
Net income			1,034				1,034
Other Comprehensive Income							
Foreign currency translation adjustments				(340)			(340)
Net unrealized gains on cash flow hedges[b]					37		37
Reclassification into earnings from cash flow hedges[c]					(102)		(102)
Minimum pension liability adjustment[d]						(484)	(484)
Total comprehensive income							145
Dividend reinvestment and employee benefits	13	342					342
Equity offering	55	975					975
Westcoast acquisition	50	1,702					1,702
Common stock dividends			(905)				(905)
Preferred and preference stock dividends			(13)				(13)
Other capital stock transactions, net			9				9
Balance December 31, 2002	**895**	**$ 9,236**	**$ 6,417**	**$ (647)**	**$ 422**	**$ (484)**	**$14,944**
Net loss			(1,323)				(1,323)
Other Comprehensive Loss							
Foreign currency translation adjustments[a]				986			986
Foreign currency translation adjustments reclassified into earnings as a result of the sale of European operations				(24)			(24)
Net unrealized gains on cash flow hedges[b]					116		116
Reclassification into earnings from cash flow hedges[c]					(240)		(240)
Minimum pension liability adjustment[d]						40	40
Total comprehensive loss							(445)
Dividend reinvestment and employee benefits	16	283	(6)				277
Common stock dividends			(993)				(993)
Preferred and preference stock dividends			(15)				(15)
Other capital stock transactions, net			(20)				(20)
Balance December 31, 2003	**911**	**$ 9,519**	**$ 4,060**	**$ 315**	**$ 298**	**$ (444)**	**$13,748**
Net income			1,490				1,490
Other Comprehensive Income							
Foreign currency translation adjustments				279			279
Foreign currency translation adjustments reclassified into earnings as a result of the sale of Asia-Pacific Business				(54)			(54)
Net unrealized gains on cash flow hedges[b]					311		311
Reclassification into earnings from cash flow hedges[c]					(83)		(83)
Minimum pension liability adjustment[d]						28	28
Total comprehensive income							1,971
Dividend reinvestment and employee benefits	5	108	20				128
Equity offering	41	1,625					1,625
Common stock dividends			(1,018)				(1,018)
Preferred and preference stock dividends			(9)				(9)
Other capital stock transactions, net			(4)				(4)
Balance December 31, 2004	**957**	**$11,252**	**$ 4,539**	**$ 540**	**$ 526**	**$ (416)**	**$16,441**

[a] Foreign currency translation adjustments, net of $114 tax benefit in 2003
[b] Net unrealized gains on cash flow hedges, net of $170 tax expense in 2004, $49 tax expense in 2003 and $72 tax expense in 2002
[c] Reclassification into earnings from cash flow hedges, net of $45 tax benefit in 2004, $130 tax benefit in 2003 and $94 tax benefit in 2002
[d] Minimum pension liability adjustment, net of $18 tax expense in 2004, $27 tax expense in 2003 and $309 tax benefit in 2002

Pages 1 and 4 of the Chairman's letter reference a 2004 ongoing basic earnings-per-share goal of $1.20, which we beat by 18 cents. Page 4 of the Chairman's letter also references the 2005 ongoing basic earnings-per-share target of $1.60. Ongoing basic earnings per share is a non-GAAP (generally accepted accounting principles) financial measure because it excludes the per-share effects of any "special items," which represent certain income or charges which management believes will not be recurring on a regular basis. The most directly comparable GAAP measure is basic earnings per share.

Information to reconcile the 2005 ongoing basic earnings-per-share target to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project special items for 2005. The following is a reconciliation of ongoing to reported basic earnings per share for 2004:

Ongoing Basic Earnings per Share – 2004
(In millions, except earnings per share)

	Pre-tax Amount	Tax Effect	Basic EPS Impact
Ongoing Basic Earnings per Share			**$ 1.38**
Net gain on sale of discontinued operations (net of minority interest of $7 million)	$ 278	$ (16)	0.28
Net loss on asset sales, primarily sale of southeast U.S. plants (including minority interest benefit of $25 million)	(206)	72	(0.14)
Impairments and other related charges (net of minority interest of $12 million)	(25)	9	(0.02)
Litigation reserves and settlements (net of minority interest of $5 million) and contract termination charges	(5)	2	0.00
Tax benefit from restructuring	–	48	0.05
Adjustment to captive insurance reserve	64	(22)	0.04
Net loss on sales of equity investments (including minority interest benefit of $7 million) and loss on asset exchanges	(8)	3	0.00
Total basic earnings-per-share impact of special items			0.21
Basic Earnings per Share, as Reported			**$ 1.59**

Page 1 of the Chairman's letter references a debt reduction of $4.6 billion. This amount represents a non-GAAP measure because it includes changes in amounts presented in the Consolidated Balance Sheets as other than "debt," including amounts classified as "liabilities associated with assets held for sale" and "minority interests." The following is a reconciliation of the $4.6 billion to the changes in the amounts reported in the Consolidated Balance Sheets as "debt":

Reconciliation of Debt Paydown to Consolidated Balance Sheets – 2004
(In millions)

	12/31/03	12/31/04	Difference
Long-term debt	$20,622	$16,932	$ (3,690)
Current maturities of long-term debt and preferred stock	1,200	1,832	632
Notes payable and commercial paper	130	68	(62)
Total Debt	21,952	18,832	**(3,120)**
Changes due to foreign currency			(300)
Other cash changes			(89)
Sub-total			**(389)**
Redeem Australia debt			(890)
Redeem Westcoast Energy, Inc. preferred securities			(176)
Total Change			**$(4,575)**
Total debt paydown disclosed			$ (4,600)

Page 1 of the Chairman's letter references $3.1 billion of proceeds from asset sales in 2004. This amount represents a non-GAAP measure because it includes amounts that are presented in the Consolidated Statements of Cash Flows as other than net "proceeds from sales of equity investments and other assets, and sales of and collections on notes receivable," including $750 million of tax benefits and $840 million of non-cash debt reductions.

The Financial Highlights on page 2 include amounts for "earnings (loss) before interest and taxes from continuing operations." This non-GAAP measure represents the combination of "operating income (loss)" and "other income and expenses" as presented in the Consolidated Statements of Operations, and it excludes results and impacts from discontinued operations.

Page 3 of the Chairman's letter mentions a 2004 contribution from Crescent Resources of more than $440 million. This amount represents the cash that Crescent Resources generated from its operating and investing activities and contributed to Duke Energy.

In this report, for certain segments we use ongoing segment EBIT (earnings before interest and taxes) as a measure of historical and anticipated future performance. For some segments we also use a forecasted ongoing segment EBIT growth rate, which is based on historical and forecasted ongoing segment EBIT, as an indicator of anticipated future compound annual growth rates. When used for future periods, ongoing segment EBIT may also include amounts that may be reported as discontinued operations. Ongoing segment EBIT and related growth rates are non-GAAP financial measures because they represent reported segment EBIT adjusted for special items. The most directly comparable GAAP measure for ongoing segment EBIT is reported segment EBIT, which represents EBIT from continuing operations, including any special items.

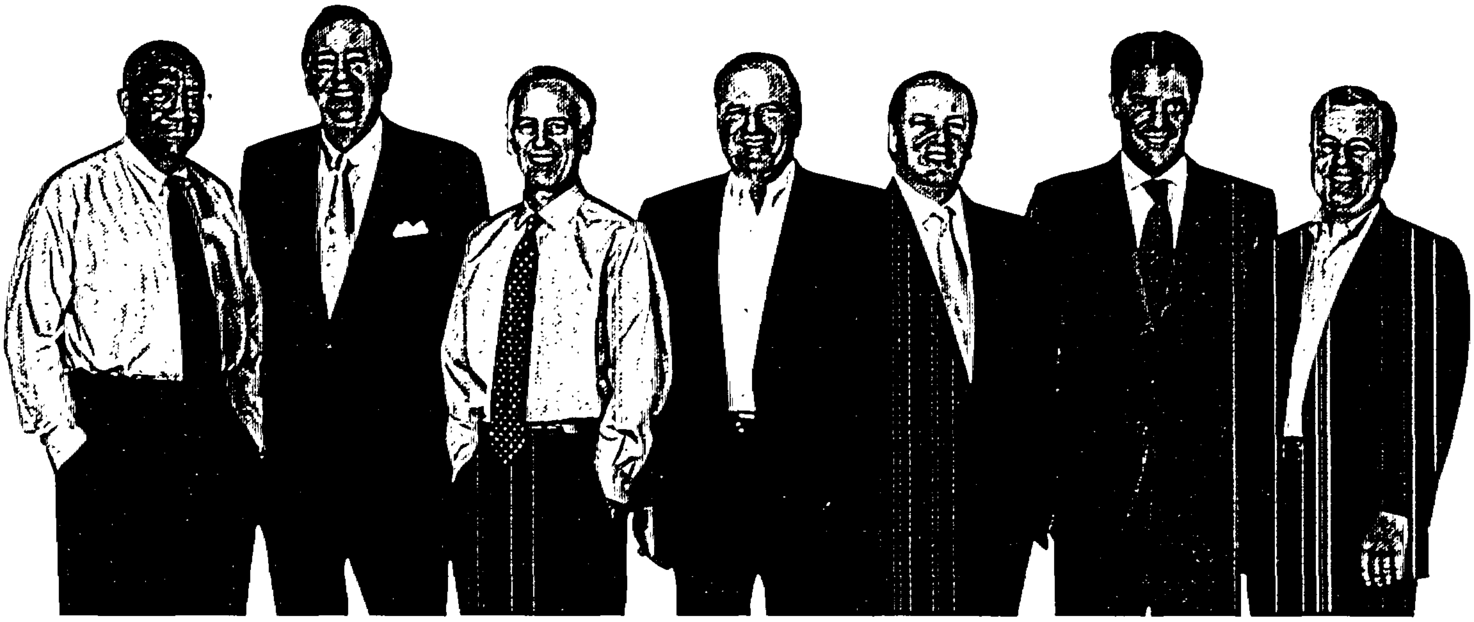
For future periods, information to reconcile ongoing segment EBIT and related growth rates to the most directly comparable GAAP financial measures is not available at this time, as management is unable to forecast special items or amounts that may be reported as discontinued operations. The following is a reconciliation of ongoing segment EBIT to reported segment EBIT for 2004:

Reconciliation of Ongoing to Reported Segment EBIT – 2004
(In millions)

		Special Items						
	Ongoing Segment EBIT	**Gains (Losses) on Sales of Assets**	**Gains (Losses) on Sales of Equity *Investments***	**Impairment and Other Related *Charges***	**Early Contract Termination *Charges***	**Enron/ California Settlements, *net***	***Total***	**Reported Segment EBIT**
Earnings Before Interest and Taxes from Continuing Operations								
Duke Energy North America	$(288)	$(228)[a]	$–	$ (2)	$(20)[b]	$3[b,c]	$(247)	$(535)
International Energy	236	(2)	1	(13)[b]	–	–	(14)	222

a Net of minority interest benefit of $26 million
b Recorded in operation and maintenance expense
c Net of minority interest of $5 million

BOARD OF DIRECTORS



(Left to right) Robert J. Brown, George Dean Johnson Jr., G. Alex Bernhardt Sr., A. Max Lennon, Paul M. Anderson, Roger Agnelli, James T. Rhodes

BOARD MEMBERS

Roger Agnelli, *45, President and Chief Executive Officer, Companhia Vale do Rio Doce (CVRD), Brazil. Compensation Committee. Finance and Risk Management Committee. Director since 2004.* Agnelli leads CVRD, a global mining company and the world's largest producer of iron ore. For several years he held various positions at Bradesco, a Brazilian financial conglomerate. Agnelli joined Duke Energy's Board of Directors in November 2004.

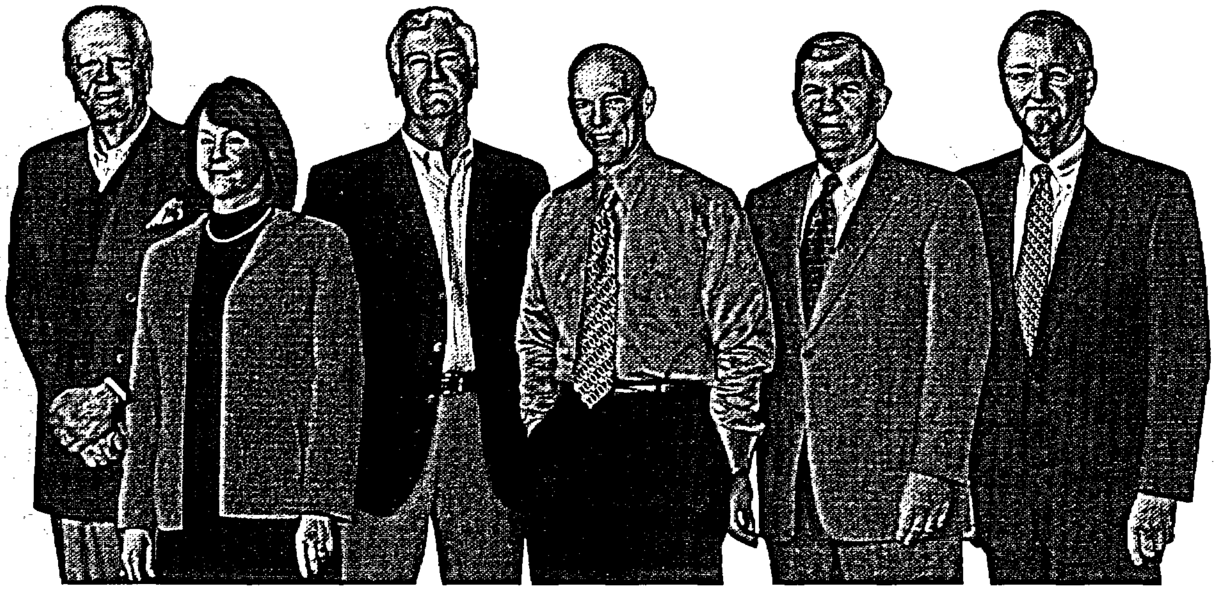
Paul M. Anderson, *59, Chairman of the Board and Chief Executive Officer, Duke Energy. Director since 2003.* Anderson rejoined Duke Energy in 2003, having served as its first president and chief operating officer in 1997 and 1998, and with Duke Energy predecessor companies since 1977. He retired as managing director and chief executive officer of Australia-based BHP Billiton Ltd. in 2002.

G. Alex Bernhardt Sr., *62, Chairman and Chief Executive Officer, Bernhardt Furniture Co. Audit Committee. Nuclear Oversight Committee. Director since 1991.* Besides leading the family business in Lenoir, N.C., Bernhardt serves as a director of Cities in Schools and Smart Start, and on the Davidson College Board of Trustees.

Robert J. Brown, *70, Chairman and Chief Executive Officer, B&C Associates Inc. Audit Committee. Corporate Governance Committee. Director since 1994.* Brown founded B&C Associates Inc., a marketing research and public relations firm in High Point, N.C. He serves on the Board of Trustees of the National Urban League. Brown will retire from the Duke Energy Board of Directors at the 2005 Annual Meeting.

William T. Esrey, *65, Chairman Emeritus, Sprint Corp. Chair, Audit Committee. Director since 1985.* Esrey joined Sprint in 1980, and went on to serve as the company's chief financial officer, president, chief executive officer and chairman. He also served as chairman of Japan Telecom from 2003 to 2004.

Ann Maynard Gray, *59, Former President, Diversified Publishing Group of ABC Inc. Lead Director. Chair, Corporate Governance Committee. Compensation Committee. Finance and Risk Management Committee. Nuclear Oversight Committee. Director since 1994.* At American Broadcasting Companies Inc., Gray also held positions as treasurer and vice president of planning. She currently serves as a trustee for J.P. Morgan Funds.



(Left to right) Leo E. Linbeck Jr., Ann Maynard Gray, Michael E.J. Phelps, William T. Esrey, James G. Martin, Dennis R. Hendrix

Dennis R. Hendrix, *65, Retired Chairman of the Board, PanEnergy Corp. Compensation Committee. Finance and Risk Management Committee. Director since 2004.* Hendrix rejoined the Board of Directors in December 2004. He was chairman of the board of PanEnergy Corp prior to the 1997 merger of Duke Power and PanEnergy.

George Dean Johnson Jr., *62, Owner, Johnson Development Associates Inc. Finance and Risk Management Committee. Director since 1986.* Johnson was formerly chief executive officer and director of Extended Stay America Inc. He served in the S.C. House of Representatives and as a director of the Federal Reserve Bank of Richmond. Johnson will retire from the Duke Energy Board of Directors at the 2005 Annual Meeting.

A. Max Lennon, *64, President, Education and Research Services. Audit Committee. Director since 1988.* Lennon is a former president of Clemson University and Mars Hill College. He also served as president and chief executive officer of Eastern Foods Inc.

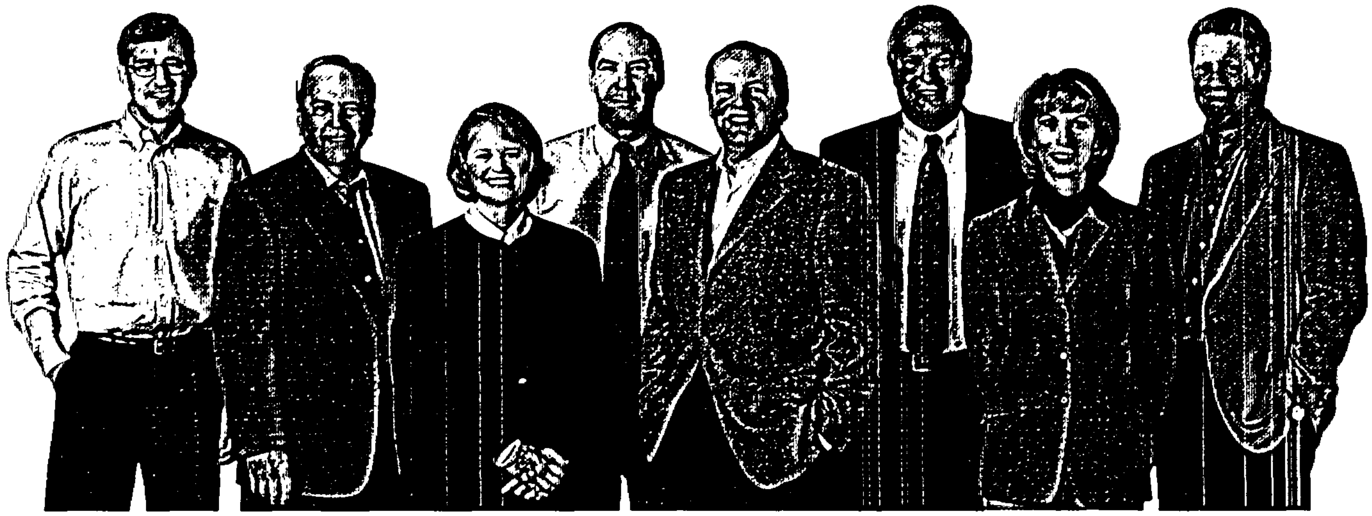
Leo E. Linbeck Jr., *70, Senior Chairman, Linbeck Corp. Compensation Committee. Finance and Risk Management Committee. Director since 1986.* Linbeck Corp. is a group of four construction-related firms headquartered in Houston, Texas. Linbeck is past chairman and director of the Federal Reserve Bank of Dallas. He will retire from the Duke Energy Board of Directors at the 2005 Annual Meeting.

James G. Martin, *69, Corporate Vice President, Carolinas HealthCare System. Chair, Compensation Committee. Corporate Governance Committee. Nuclear Oversight Committee. Director since 1994.* Martin was governor of the state of North Carolina from 1985 to 1993, and previously served as a U.S. congressman. He is chairman of the Global TransPark Foundation Inc.

Michael E.J. Phelps, *57, Chairman, Dornoch Capital Inc. Chairman, Duke Energy Canadian Advisory Council. Chair, Finance and Risk Management Committee. Corporate Governance Committee. Director since 2002.* Phelps is former chairman of the board and chief executive officer of Westcoast Energy Inc., acquired by Duke Energy in 2002.

James T. Rhodes, *63, Retired Chairman, President and Chief Executive Officer, Institute of Nuclear Power Operations. Chair, Nuclear Oversight Committee. Audit Committee. Director since 2001.* Rhodes was formerly president and chief executive officer of Virginia Power. He is a member of the Advisory Council of the Electric Power Research Institute.

EXECUTIVE MANAGEMENT



2004 Executive Committee (left to right): A.R. Mullinax, Fred Fowler, Martha Wyrsch, Jim Mogg, Paul Anderson, David Hauser, Julie Dill, Rich Osborne

EXECUTIVE COMMITTEE

Duke Energy's Executive Committee is responsible for driving a strategy that generates shareholder value by providing a stable platform for growth and continued profitability. This group develops corporate strategy, allocates capital, outlines enterprise goals, implements Board direction, and in general leads the enterprise.

Paul M. Anderson, *Chairman of the Board and Chief Executive Officer.* Anderson has lead responsibility for positioning Duke Energy as a company that achieves superior results, focusing the organization on its vision and purpose, improving execution and ensuring clear accountability. He chairs the Executive Committee and the Expanded Executive Committee.

Fred J. Fowler, *President and Chief Operating Officer.* Fowler chairs Duke Energy's Enterprise Performance Committee, with responsibility for the operational, commercial and financial results of the company's energy-related businesses.

David L. Hauser, *Group Vice President and Chief Financial Officer.* Hauser is responsible for treasury, accounting, tax and risk management. His duties include certifying financial statements and overseeing risk control policies and systems.

Jim W. Mogg, *Group Vice President and Chief Development Officer.* Mogg oversees strategy and corporate transactions, corporate and human resources development, mergers and acquisitions, diversity and the company's real estate affiliate.

A.R. Mullinax, *Group Vice President and Chief Information Officer.* Mullinax leads information technology and is responsible for global sourcing and logistics, corporate real estate services and human resources services.

Richard J. Osborne, *Group Vice President, Public and Regulatory Policy.* Osborne has responsibility for Duke Energy's public policy agenda and relationships with regulators, legislators, communities and other key stakeholders.

Martha B. Wyrsch. Wyrsch served as group vice president, general counsel and secretary until March 1, 2005, when she became president and chief executive officer of Duke Energy Gas Transmission.

Julie A. Dill, *Secretary to the Executive Committee and Vice President, Investor and Shareholder Relations.* Dill is responsible for relationships and communication with the investment community, and for monitoring changes and trends in investment markets.

EXPANDED EXECUTIVE COMMITTEE

The Expanded Executive Committee includes the Executive Committee members as well as the heads of the major business units. This group is responsible for corporate policies and programs that reach across the business units.

(Pictured on page 6)

William H. Easter III, *Chairman, President and Chief Executive Officer, Duke Energy Field Services.* Easter leads the company's natural gas gathering and processing and natural gas liquids business.

Robert B. Evans, *President and Chief Executive Officer, Duke Energy Americas.* Evans is responsible for Duke Energy's North American and Latin American wholesale energy generation business.

Thomas C. O'Connor. O'Connor served as president and chief executive officer of Duke Energy Gas Transmission until March 1, 2005. He will have responsibilities for corporate strategy upon his completion of Harvard University's Advanced Management Program, and will be joining the Executive Committee later in 2005.

Ruth G. Shaw, *President and Chief Executive Officer, Duke Power Company.* Shaw oversees the electric utility that serves more than 2 million customers in North Carolina and South Carolina.

Annual Meeting
The 2005 Annual Meeting of Duke Energy Shareholders will be:
Date: Thursday, May 12, 2005
Time: 10 a.m.
Place: O.J. Miller Auditorium,
Energy Center
526 South Church Street
Charlotte, NC 28202

Shareholder Services
Shareholders may call (800) 488-3853 or (704) 382-3853 with questions about their stock accounts, legal transfer requirements, address changes, replacement dividend checks, replacement of lost certificates or other services. Additionally, registered users of DUK-Online, our online account management service, may access their accounts through the Internet.
Send written requests to:
Investor Relations
Duke Energy
P.O. Box 1005
Charlotte, NC 28201-1005
For electronic correspondence, please go to "Contact Investor Relations" at: www.duke-energy.com/investors.

Stock Exchange Listing
Duke Energy's common stock and certain issues of first and refunding mortgage bonds, preferred securities and senior notes are listed on the New York Stock Exchange. The company's common stock trading symbol is DUK.

Web Site Addresses
Corporate home page:
www.duke-energy.com
Investor Relations:
www.duke-energy.com/investors

InvestorDirect Choice Plan
The InvestorDirect Choice Plan provides a simple and convenient way to purchase common stock directly through the company, without incurring brokerage fees. Purchases may be made weekly. Bank drafts for monthly purchases, as well as a safekeeping option for depositing certificates into the plan, are available. The plan also provides for full reinvestment, direct deposit or cash payment of dividends. Additionally, participants may register for DUK-Online.

Financial Publications
Duke Energy will furnish to any shareholder, without charge, printed copies of the 2004 Summary Annual Report and SEC Form 10-K. Those and other financial publications can also be found on our Web site at www.duke-energy.com/investors.

Electronic Delivery
With a shareholder's consent, we can stop mailing paper copies of financial information and proxy statements. You can go to www.icsdelivery.com/duk to enroll in electronic delivery. You will need to provide your Social Security number or Tax I.D. number, your e-mail address, and a PIN number of your choice for electronic voting.

Duplicate Mailings
If your shares are registered in different accounts, you may receive duplicate mailings of annual reports, proxy statements and other shareholder information. Call Investor Relations for instructions on eliminating duplications or combining your accounts.

Transfer Agent and Registrar
Duke Energy maintains shareholder records and acts as transfer agent and registrar for the company's common and preferred stock issues.

Dividend Payment
Duke Energy has paid quarterly cash dividends on its common stock for 78 consecutive years. Dividends on common and preferred stock are expected to be paid, subject to declaration by the Board of Directors, on March 16, June 16, Sept. 16 and Dec. 16, 2005.

Bond Trustee
If you have questions regarding your bond account, call (800) 275-2048, or write to:
JPMorgan Chase Bank
Institutional Trust Services
P.O. Box 2320
Dallas, TX 75221-2320

We welcome your opinion on Duke Energy's 2004 Annual Report. Please visit www.duke-energy.com/investors, where you can view the online Annual Report and provide feedback on both the print and online versions. Or contact Investor Relations directly.

Duke Energy®

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Charlotte, NC 28202-1802
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Grant Thornton

Financial Statements and Report of
Independent Certified Public Accountants

North Carolina Electric Membership Corporation

As of December 31, 2004, 2003 and 2002

North Carolina Electric Membership Corporation

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Grant Thornton

Accountants and Business Advisors

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

To the Board of Directors of
North Carolina Electric Membership Corporation:

We have audited the accompanying balance sheets of **North Carolina Electric Membership Corporation**, a North Carolina corporation, as of December 31, 2004 and 2003, and the related statements of operations and members' equity and cash flows for the years ending December 31, 2004, 2003 and 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America as established by the Auditing Standards Board of the American Institute of Certified Public Accountants and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements and 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, the financial statements referred to above present fairly, in all material respects, the financial position of North Carolina Electric Membership Corporation as of December 31, 2004 and 2003, and the results of its operations and its cash flows for the years ending December 31, 2004, 2003 and 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note A to the financial statements, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003.

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Suite 130
Raleigh, NC 27612
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In accordance with *Government Auditing Standards,* we have also issued a report dated February 18, 2005, on our consideration of North Carolina Electric Membership Corporation's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audit.

GRANT THORNTON LLP

Raleigh, North Carolina
February 18, 2005

North Carolina Electric Membership Corporation

Balance Sheets
December 31, 2004 and 2003
(in thousands)

Assets	2004	2003
Electric plant:		
In-service	$1,457,854	$1,493,746
Accumulated depreciation	(742,008)	(730,892)
	715,846	762,854
Nuclear fuel, at amortized cost	29,103	32,761
Construction work-in-process	14,894	1,083
	759,843	796,698
Other assets and investments:		
Long-term investments	37,785	38,603
Noncurrent receivables	15,310	16,608
Investments in associated organizations	7,490	7,469
Special deposits	31,091	30,115
Decommissioning fund	75,661	72,069
	167,337	164,864
Current assets:		
Cash and cash equivalents	17,700	11,000
Short-term investments	7,009	8,747
Accounts receivable	115,964	105,484
Accounts receivable – Affiliated companies, net	595	1,244
Interest receivable	941	1,073
Other current assets	15,821	21,773
	158,030	149,321
Deferred charges:		
Regulatory asset (Note A)	29,058	37,100
Deferred loss on debt extinguishment (Note F)	13,347	14,719
Debt issuance costs	6,173	6,651
Preliminary project costs	7,418	7,418
Other	1,682	3,413
	57,678	69,301
	$1,142,888	$1,180,184

Members' Equity and Liabilities	2004	2003
Members' equity:		
Membership fees	$ 1	$ 1
Patronage capital	22,112	22,112
Net unrealized gain on available-for-sale securities	4,555	7,269
	26,668	29,382
Long-term debt	848,411	896,060
Current liabilities:		
Current maturities of long-term debt	59,062	45,113
Accounts payable	67,580	61,018
Accrued interest	13,392	155
Other accrued expenses	13,468	11,785
	153,502	118,071
Deferred credits and other liabilities:		
Asset retirement obligation (Note A)	103,088	128,618
Accrued Department of Energy assessment	2,546	3,078
Other noncurrent liabilities	8,673	4,975
	114,307	136,671
Commitments and contingencies (Notes G, H, I, J and K)		
	$1,142,888	$1,180,184

The accompanying notes are an integral part of these financial statements.

North Carolina Electric Membership Corporation

Statements of Operations and Members' Equity
For the Years Ended December 31, 2004, 2003 and 2002

(in thousands)

	2004	2003	2002
Operating revenues	$802,733	$772,519	$749,200
Operating expenses:			
Fuel and purchased power	561,725	526,145	515,071
Other production expenses	114,764	114,176	104,104
Depreciation and amortization	45,921	45,718	38,956
Administrative and general	16,541	18,927	19,588
General taxes	11,796	11,709	11,633
	750,747	716,675	689,352
Operating margin	51,986	55,844	59,848
Other income:			
Interest and dividend income	5,979	5,393	3,735
Other	1,022	121	333
	7,001	5,514	4,068
Interest charges:			
Interest expense	56,673	59,059	61,637
Debt fees and expenses	2,314	2,299	2,279
	58,987	61,358	63,916
Net margin	0	0	0
Change in net unrealized gain on available-for-sale securities	(2,714)	4,385	2,829
Comprehensive (loss) income	(2,714)	4,385	2,829
Members' equity, beginning of year	29,382	24,997	22,168
Members' equity, end of year	$ 26,668	$ 29,382	$ 24,997

The accompanying notes are an integral part of these financial statements.

North Carolina Electric Membership Corporation

Statements of Cash Flows
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
Cash flows from operating activities:			
Net margin	$ 0	$ 0	$ 0
Adjustments to reconcile net margin to net cash and cash equivalents provided by operating activities:			
Depreciation and amortization	45,921	45,718	38,956
Other amortization	5,023	5,335	1,207
Amortization of nuclear fuel	14,623	16,775	14,928
Interest on decommissioning fund	0	0	237
Deferred charges	(1,180)	(5,536)	22,889
Other noncurrent assets and liabilities	4,996	3,089	4,381
Changes in other operating assets and liabilities:			
Accounts receivable	(9,831)	17,014	(17,245)
Interest receivable	132	(242)	204
Accounts payable	6,562	10,057	10,538
Accrued interest	13,237	24	(43)
Wholesale power cost adjustment	5,218	(17,896)	(2,603)
Other	277	236	369
Net cash and cash equivalents provided by operating activities	84,978	74,574	73,818
Cash flows from investing activities:			
Additions to electric plant	(41,439)	(30,223)	(20,876)
Increase in decommissioning fund	(3,746)	(8,661)	(237)
Decrease (increase) in long-term investments	472	(3,451)	(2,328)
Decrease (increase) in short-term investments	1,657	4,101	(2,156)
Other, net	(1,522)	(1,716)	(4,495)
Net cash and cash equivalents used in investing activities	(44,578)	(39,950)	(30,092)
Cash flows from financing activities – Principal payments of long-term debt	(33,700)	(42,560)	(40,458)
Net increase (decrease) in cash and cash equivalents	6,700	(7,936)	3,268
Cash and cash equivalents, beginning of year	11,000	18,936	15,668
Cash and cash equivalents, end of year	$17,700	$11,000	$18,936
Supplemental disclosures of cash flow information:			
Transfer of intercompany accounts receivable from current to noncurrent:			
Accounts receivable, affiliated companies, net	$ 0	$ (8,605)	$ 0
Noncurrent receivables	0	8,605	0
Implementation of FAS 143:			
(Disposal) addition of decommissioning asset	(26,206)	28,824	0
Increase (decrease) in deferred credits and other liabilities	32,003	(63,283)	0
(Decrease) increase in regulatory asset	(5,797)	34,999	0
Reclass of other noncurrent liabilities:			
Preliminary project costs	0	(2,000)	0
Other noncurrent liabilities	0	2,000	0
Cash paid during the year for:			
Interest	43,435	59,036	61,680
Income taxes	0	0	0

The accompanying notes are an integral part of these financial statements.

Note A - Summary of Significant Accounting Policies

Basis of Accounting

North Carolina Electric Membership Corporation (the Company) is a member-owned cooperative of 26 electric membership cooperatives (the members) in North Carolina. The Company was formed in 1949 to develop itself as a full-requirements supplier, providing power generation, wholesale electric service and transmission to its members, who in turn service more than 860,000 homes, farms and businesses in North Carolina. The Company follows accounting principles generally accepted in the United States of America and the practices prescribed in the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC) as modified and adopted by the Rural Utilities Service (RUS). Effective January 1, 2004, four members elected to independently obtain their future power supply resources. Another member elected to independently obtain its future power supply resources, effective May 1, 2005, or a later date to be mutually agreed upon by the parties. See the Member Power Supply Resource Policy for further discussion.

Electric Plant

Electric plant is stated at original cost, which is the cost of the plant when placed into service plus the cost of subsequent additions and includes engineering and other indirect construction costs. The cost of renewals and betterments of property is capitalized. The cost of maintenance and repairs and replacements and renewals of items determined to be less than units of property is charged to expense when incurred. At the time properties are disposed of, the original cost plus the cost of removal less salvage of such property is charged to accumulated depreciation, except in certain cases of properties sold as entireties where profit or loss is recognized.

Depreciation and Decommissioning

Depreciation is computed using the straight-line method over the estimated service lives of the property as follows:

	Estimated Lives
Catawba Nuclear Station (Catawba)	23-40 years
Diesel generation equipment	30 years
Load management equipment	15 years
Building and improvements	35 years
Furniture and fixtures	5-10 years
Computers and telecommunications equipment	3-10 years
Vehicles	4 years

The Company reviews its long-lived assets for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. If this review indicates that the asset will not be recoverable based on the expected undiscounted net cash flows of the related asset, an impairment loss is recognized and the asset's carrying value is reduced. No such impairment loss was recognized in 2004, 2003 or 2002.

The estimate of the expected cost for decommissioning is adjusted periodically to reflect changing price levels and technology. Using a 1999 site study of expected decommissioning costs, including the costs of decontamination, dismantling and site restoration, the Company estimated its portion of such costs to be approximately $246,224,000 in 1999 dollars. The decommissioning cost estimates are based on the plant location and cost characteristics for Catawba and assume prompt dismantlement and removal of the plant from service. The actual decommissioning costs are expected to vary from the above estimates because of changes in assumed dates of decommissioning, changes in regulatory requirements, changes in technology and changes in costs of labor, materials and equipment.

The Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations," on January 1, 2003, to provide for the expected cost of decommissioning Catawba. SFAS No. 143 establishes accounting and reporting standards for the way companies recognize and measure retirement obligations that result from the operation of a long-lived asset. SFAS No. 143 requires that the fair value of asset retirement obligations be recorded in the balance sheet at the time the liability is incurred which, in most cases, will be when the asset is placed in service. The cost associated with recognizing this obligation is capitalized into the cost of the related long-lived asset. The implementation of SFAS No. 143 on January 1, 2003, resulted in a cumulative effect of a change in accounting principle of $34,999,000, which was recorded as a regulatory asset and was to be amortized over the remaining life of Catawba. Additionally, implementation resulted in a net increase in Electric Plant of $28,824,000 and an increase in deferred credits and other liabilities of $63,823,000. In compliance with a Nuclear Regulatory Commission (NRC) regulation, amounts recovered through rates for estimated decommissioning costs (plus interest thereon) are maintained in a separate external trust fund.

In November 2003, the NRC extended the licenses for Catawba through December 31, 2043. As such, in 2004, the Company received an updated site study that included consideration of the extended licenses for Catawba. Using this study, the Company estimates its portion of expected decommissioning costs to be approximately $281,056,000 in 2003 dollars. The new study resulted in a change in accounting estimate of $5,797,000, which was recorded as a reduction to the regulatory asset, which will continue to be amortized over the remaining life of Catawba. In addition, the new study resulted in a net decrease in Electric Plant of $26,206,000 and a decrease in asset retirement obligation of $32,003,000.

Regulatory Assets and Deferred Charges

The Company currently complies with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended and, accordingly, has recorded regulatory assets related to its operations. This statement requires that regulatory assets be probable of future recovery at each balance sheet date. If recovery of the regulatory assets becomes unlikely or uncertain, these accounting standards may no longer apply. The Company periodically reviews these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, the Company believes that its regulatory assets are probable of future recovery.

Deferred charges, other than preliminary project costs (Note I), are amortized using the straight-line method over the following estimated periods:

	Estimated Periods
Regulatory asset	1-23 years
Deferred loss on debt extinguishment (Note F)	15-24 years
Debt issuance costs	19-24 years
Other	1-5 years

Nuclear Fuel

The cost of nuclear fuel, including a provision for the estimated cost of permanent storage of spent fuel, is being amortized based on core burn-up and amounted to $14,623,000 in 2004, $16,775,000 in 2003 and $14,928,000 in 2002. Final disposition of the spent fuel may require future adjustments to fuel expense. Pending ultimate disposition, sufficient storage capacity for spent fuel is available through 2008. The accumulated amortization is $131,445,000 and $116,822,000 at December 31, 2004 and 2003, respectively.

Derivative Accounting

The Company complies with the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. SFAS No. 133 requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Substantially all of the Company's bulk power purchases and sales meet the definition of a derivative under SFAS No. 133. However, these transactions also meet the normal purchase and sale exception under SFAS No. 133 and, therefore, do not need to be accounted for as derivatives.

In addition, the Company uses derivative instruments to manage the risks associated with the impact of fluctuating natural gas fuel prices on purchased power contracts. These derivatives are carried at their fair market value as determined by broker quotes. Unrealized gains are recorded as derivative assets of $382,000 and $1,071,000 in other current assets in the accompanying balance sheets at December 31, 2004 and 2003, respectively. Unrealized losses of $1,625,000 and $173,000 are recorded as derivative liabilities in other accrued expenses in the accompanying balance sheets at December 31, 2004 and 2003, respectively. As these derivatives are designated as cash flow hedges, gains or losses are deferred as a component of members' equity and will be recognized concurrently with the hedged purchased power costs.

Membership Fees and Patronage Capital

The Company is organized and operates as a cooperative. Its cooperative members paid a total of $700 in membership fees.

Patronage capital is the net margin retained by the Company, which is allocated to members based upon their respective purchases of power from the Company.

Income Taxes

The Company is a not-for-profit membership corporation exempt from federal income taxes. In management's opinion, based on the applicable statutes, the Company is not subject to state income taxes.

For the years 1984 and prior, the Company claimed tax-exempt status under Section 501(c)(12) of the Internal Revenue Code of 1954 (the Code), as amended. In 1985, the Company reported as a taxable entity as a result of income received from Duke Power Company (Duke) under a capacity and energy sell-back agreement applicable to Catawba Units No. 1 and 2. As a taxable electric cooperative, the Company annually allocated its income and deductions between member and nonmember activities. Any member taxable income was offset with a patronage exclusion.

In 1999, the Company reapplied for tax-exempt status under Section 501(c)(12) of the Code. The application was approved by the Internal Revenue Service retroactively to January 1, 1996.

Cash and Cash Equivalents

The Company considers all temporary cash investments purchased with an original maturity of three months or less to be cash equivalents.

Revenue Recognition

The Company recognizes revenue on the sale of power when supplied to members. Amounts for which revenue has been billed and not collected are included as accounts receivable in the accompanying balance sheets. Accounts receivable are due within 60 days and are stated as amounts due from members net of an allowance for doubtful accounts. Accounts outstanding longer than the payment terms are considered past due. No provision for doubtful accounts was recorded during the years ended December 31, 2004, 2003 and 2002.

The Company implemented a wholesale power cost adjustment in 2002 as a means of collecting monthly costs in excess of budget amounts or returning monthly revenue in excess of budget amounts. The wholesale power cost adjustment is returned to or collected from the members over the six-month period following the month in which the variance occurred. During 2004 and 2003, the Company incurred costs in excess of budget of $39,854,000 and $39,027,000, respectively. Of the 2004 amount, $24,572,000 was collected from the members in 2004 and $15,282,000 was recorded as other current assets at December 31, 2004, to be collected in 2005. Of the 2003 amount, $18,528,000 was collected from members in 2003 and $20,499,000 was recorded as other current assets at December 31, 2003, and collected in 2004.

Member Power Supply Resource Policy

In February 1998, the Company adopted a policy allowing members to independently procure a portion of their future wholesale power supply if they so desired. The policy was revised in 2002 and 2003 to reflect changes in the marketplace. In June 2003, four members (Independent Members) elected to exercise their rights consistent with the policy to independently arrange for future purchases of capacity and energy. Each of the four members executed a wholesale power supply agreement with the Company effective January 1, 2004, that will remain in effect until December 31, 2026. The Independent Members continue to be responsible for their share of capacity and energy commitments made by the Company prior to January 1, 2004. In 2004, another member elected to exercise its rights to independently arrange for future purchases of capacity and energy. This agreement will become effective May 1, 2005, or at a later date to be mutually agreed upon by the parties. The new Independent Member will continue to be responsible for its share of capacity and energy commitments as agreed upon by the parties.

Concentration of Credit Risk

One member accounted for approximately 9.2%, 12.9% and 12.9% of revenues during 2004, 2003 and 2002, and 6.4%, 8.9%, 13.6% of accounts receivable at December 31, 2004, 2003 and 2002, respectively.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

Certain reclassifications have been made to the prior-year financial statements to conform to the current-year presentation.

Recent Accounting Pronouncements

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," effective for financial instruments entered into or modified after May 31, 2003, and otherwise effective at the beginning of the first interim period beginning after June 15, 2003, except for mandatorily redeemable financial instruments of nonpublic entities. The application of this statement has been indefinitely deferred for nonpublic entities with mandatorily redeemable financial instruments. This statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. The Company does not believe that it will be affected by this statement.

In May 2003, the Emerging Issues Task Force (EITF) issued EITF Abstract No. 01-8, "Determining Whether an Arrangement Contains a Lease," effective for agreements entered into or modified after the beginning of the first fiscal period subsequent to May 28, 2003. This abstract establishes criteria for determining whether an agreement which has fixed supply requirements, called "Take-or-Pay contracts," or agreements which provide one party with the right to use property, plant and equipment qualify as lease agreements. The Company is not affected by this abstract.

Note B - Jointly Owned Electric Plant and Related Agreements

On February 6, 1981, the Company entered into (a) the Catawba Nuclear Station Purchase, Construction and Ownership Agreement with Duke, together with (b) an Operating and Fuel Agreement and (c) an Interconnection Agreement (the Contracts). Contracts (a) and (b) basically provide for the purchase by the Company of a 56.25% undivided interest in Unit No. 1 of the Catawba Nuclear Station together with a 28.125% interest in the support facilities and for a sharing of direct construction and operating costs in relation to the respective ownership share of the parties. The Company's total investment in jointly owned facilities totaled $1,386,272,000 and $1,372,064,000, including capitalized interest expense net of related investment income, and is included in electric plant in-service in the accompanying balance sheets as of December 31, 2004 and 2003, respectively.

The cost of power purchased from Duke, as well as power purchased by the Company from other power supply sources, including Carolina Power & Light doing business as Progress Energy Carolinas, Inc. (CP&L), Dominion North Carolina Power (VEPCO) and American Electric Power Company (AEP) has been recorded as purchased power on the accompanying statements of operations and members' equity.

Note C - Fair Value of Financial Instruments

A detail of the estimated fair values of the Company's financial instruments as of December 31, 2004 and 2003, is as follows (in thousands):

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 17,700	$ 17,700	$ 11,000	$ 11,000
Short-term investments	7,009	7,009	8,747	8,747
Long-term investments	37,785	37,785	38,603	38,603
Special deposits	31,091	31,091	30,115	30,115
Decommissioning fund	75,661	75,661	72,069	72,069
Long-term debt	907,473	987,862	941,173	1,039,856

For cash and cash equivalents, the carrying amount approximates fair value due to the short maturity of those instruments. The special deposits fund balance is contractually determined to meet certain funding requirements. The fair value of the Company's long-term debt is estimated by management based on the current rates offered to the Company for debt of similar maturities.

The Company's investments may be classified as available for sale, trading or held to maturity. Available-for-sale securities are carried at market value with unrealized gains and losses added to or deducted from equity. Trading securities are also carried at market value with unrealized gains and losses charged to income. Held-to-maturity securities are carried at amortized cost. All realized and unrealized gains and losses are determined using the specific identification method. All investments are classified as available for sale.

The amortized cost, gross unrealized holding gains, gross unrealized losses and fair value of available-for-sale securities by major security type at December 31, 2004 and 2003, are as follows (in thousands):

December 31	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Estimated Fair Value
2004:				
Available-for-sale securities:				
U.S. Government and agency securities	$ 35,756	$1,350	$(235)	$ 36,871
Corporate bonds	26,749	246	(290)	26,705
Equity investments	29,008	4,856	0	33,864
Other	72,066	70	(330)	71,806
	$163,579	$6,522	$(855)	$169,246
2003:				
Available-for-sale securities:				
U.S. Government and agency securities	$ 36,778	$1,069	$(218)	$ 37,629
Corporate bonds	45,209	818	(182)	45,845
Equity investments	21,763	4,871	0	26,634
Other	50,415	95	(84)	50,426
	$154,165	$6,853	$(484)	$160,534

Proceeds from the sale of marketable securities were $186,059,000, $254,031,000 and $222,619,000 in 2004, 2003 and 2002, respectively. Related net realized gains (losses) included in income were $1,471,000, $(24,125) and $607,000 in 2004, 2003 and 2002, respectively.

Note D - Investments in Associated Organizations

Investments in associated organizations are stated at cost at December 31, 2004 and 2003, and are as follows (in thousands):

	2004	2003
TSE Services Inc. preferred stock (Note K)	$2,000	$2,000
National Rural Utilities Cooperative Finance Corporation:		
Subordinated Term Certificate	4,970	4,970
Capital Term Certificates	314	316
Patronage Capital Certificates	130	122
Other investments	76	61
	$7,490	$7,469

The Subordinated Term Certificate bears interest at 6.75% per annum. The Capital Term Certificates bear interest at 3% to 5% per annum. These certificates are required to be maintained under debt agreements with the National Rural Utilities Cooperative Finance Corporation (NRUCFC) in an amount at least equal to 5% of the original debt issued or guaranteed by NRUCFC until maturity of the related debt instruments. These investments in associated organizations are similar to compensating bank balances and are necessary in order to maintain current financing arrangements.

Note E - Special Deposits

Special deposits include debt service reserve funds for pollution control bonds as required by the Company's bond agreements and the Company's agreements with Duke. Debt service reserve funds totaled $10,062,000 and $9,686,000 at December 31, 2004 and 2003, respectively.

In 1994, under the terms of its Catawba ownership agreements with Duke as discussed in Note B, the Company entered into an Amended Depository Agreement with Duke under which the Company was required to establish a Special Reserve Fund depository account in an amount equal to the greater of $750,000 or 1% of the Company's estimated payments to Duke under the terms of the Interconnection Agreement plus one-sixth of the Company's estimated payments to Duke under terms of the Operating and Fuel Agreement during the current fiscal year. The depository account totaled $21,651,000 and $20,969,000 as of December 31, 2004 and 2003, respectively.

A portion of these deposits has been classified as short-term investments at December 31, 2004 and 2003.

Note F - Long-term Debt

Long-term debt consists of mortgage notes payable to the United States of America acting through the Federal Financing Bank (FFB) and the RUS, Pollution Control Revenue Bonds and promissory notes to NRUCFC. Substantially all assets of the Company are pledged as collateral for the debt. The terms of the mortgages, notes and bonds are as follows (in thousands):

	2004	2003
FFB mortgage and RUS note advances, maturing at various dates through 2019 with fixed interest rates ranging from 5.00% to 8.06% at December 31, 2004 and 2003	$802,498	$836,176
Pollution Control Revenue Bonds, Series 2000, with principal payments due in 2020 through 2024, guaranteed by NRUCFC, three series with interest payable monthly at varying rates (average of 1.92% at December 31, 2004, and 1.2% at December 31, 2003)	99,400	99,400
NRUCFC note, interest payable semi annually at 9.05%, principal payments due in 2024	4,970	4,970
NRUCFC note advances, interest and principal payable quarterly through June 14, 2023, interest rate of 3.6% at December 31, 2004 and December 31, 2003	605	627
	907,473	941,173
Less - Current maturities	(59,062)	(45,113)
	$848,411	$896,060

In July 1998, the Company refinanced substantially all FFB notes with an outstanding principal balance of $1,015,104,000. The interest rates on these notes were reduced from rates ranging from 7.69% to 10.52% to a fixed rate of 5.61%. This rate will remain in effect for a 10-year period ending in 2008, at which time the Company has the option to reprice the outstanding principal for the remaining term. In conjunction with the refinancing, the Company paid a penalty of $2,861,000 and financed an additional premium of $114,435,000 over the term of the original debt. The Company individually assessed the refinanced notes to determine whether each transaction should be accounted for as an extinguishment. As a result, $253,148,000 in debt was extinguished and replaced by $271,391,000 in new debt, representing the fair value of the related notes. In addition, the Company wrote off $713,000 and $2,108,000 of related refinancing penalties and original debt issuance costs, respectively. The resulting loss on extinguishment of $21,064,000 was recorded as a deferred charge to be amortized in accordance with the recovery period established by the Board of Directors. Likewise, the remaining unrecorded premium of $96,192,000 will be recognized as interest expense over the term of the debt. The unamortized balance of the refinancing premium was $74,312,000 and $77,321,000 at December 31, 2004 and 2003, respectively. This transaction will result in a net economic gain of approximately $68,647,000 over the term of the notes.

In September 2000, the Company issued Series 2000 Pollution Control Revenue Bonds, guaranteed by NRUCFC, in the amount of $99,400,000. The bonds were issued in three series, with principal payments due in 2020 through 2024. Interest on the bonds is payable monthly at varying rates. In addition, the Company borrowed $4,970,000 from NRUCFC to finance the purchase of a Subordinated Term Certificate with NRUCFC, a requirement for NRUCFC to guarantee the pollution control bonds.

Maturities of the long-term debt described above for the five-year period beginning January 1, 2005, and thereafter, are summarized below (in thousands):

Years	Amount
2005	$ 59,062
2006	50,314
2007	53,127
2008	56,185
2009	59,422
Thereafter	629,363
	$907,473

The Company also has a $48 million line of credit with NRUCFC, which was unused at December 31, 2004, 2003 and 2002. The interest rate available under this agreement would be determined at the time an advance is made. This line of credit expires in June 2005 and is subject to an annual renewal process. Borrowings on the line of credit are made on a revolving basis as needed.

Note G - Employee Benefit Plans

All employees of the Company participate in the National Rural Electric Cooperative Association (NRECA) Retirement and Security Program (the Program), a defined benefit pension plan qualified under Section 401 and tax exempt under Section 501(a) of the Code. In this multiemployer plan, which is available to all member cooperatives of NRECA, the accumulated benefits and plan assets are not determined or allocated separately by individual employer. The Company makes annual contributions to the Program equal to the annual pension expense, except during a period when a moratorium is in effect. Payments to the Program for current period service cost were $1,902,000 in 2004, $1,816,000 in 2003 and $1,725,000 in 2002.

All employees of the Company are eligible to participate in the NRECA Savings Plan, a defined contribution plan qualified under Section 401(k) and tax exempt under Section 501(a) of the Code. Eligible employees may make contributions to the plan of up to 15% of their salary. The Company matches employee contributions to the plan up to 3% of the employee's salary. Total company contributions to the NRECA Savings Plan were $308,000 in 2004, $304,000 in 2003 and $301,000 in 2002.

Note H - Other Postemployment and Postretirement Benefits

The net postretirement benefit liability recognized by the Company, included in other noncurrent liabilities on the accompanying balance sheets, is summarized as follows (in thousands):

	2004	2003
Retired plan participants	$ 1,101	$ 978
Active plan participants	3,947	3,888
Unrecognized actuarial loss	(1,085)	(1,494)
Accumulated postretirement benefit obligation	$3,963	$3,372

Net postretirement benefit cost for 2004, 2003 and 2002 is included in administrative and general expenses and consists of the following components (in thousands):

	2004	2003	2002
Service cost - Benefits attributed to service during the period	$359	$325	$256
Interest cost on accumulated postretirement benefit obligation	274	288	225
Amortization of actuarial gain	43	76	42
Net postretirement benefit cost	$676	$689	$523

Disclosures required by SFAS No. 132, "Employers' Disclosure about Pensions and Other Postretirement Benefits," with regard to the Company's postretirement benefits are as follows (in thousands):

	2004	2003
Benefit obligation at December 31	$3,963	$3,372
Fair value of plan assets at December 31	0	0
Funded status – Accrued benefit cost recognized in the balance sheet	$3,963	$3,372
Weighted average assumptions as of December 31:		
Discount rate	6.25%	6.75%
Rate of compensation increase	N/A	N/A
Health care trend rate (decreases annually to 5.0% by 2014)	12%	14%
Benefit cost	$ 676	$ 689
Employer contribution	85	81
Plan participants' contributions	N/A	N/A
Benefits paid	134	116

Projected future benefit payments are as follows:

Years	Amount
2005	$ 157
2006	161
2007	197
2008	240
2009	277
2010 to 2014	1,877

The Company has revised certain assumptions related to the computation of the accumulated postretirement benefit obligation, resulting in a net actuarial loss of $1,085,000 in 2004. Increasing the assumed health care cost trend by one percentage point would increase the accumulated postretirement benefit obligation for 2004 by $872,000.

Note I - Commitments and Contingencies

Department of Energy Assessment

The Energy Policy Act of 1992 gave the Department of Energy (DOE) the authority to assess utilities for the decommissioning of its facilities used for the enrichment of uranium included in nuclear fuel costs. In order to decommission these facilities, the DOE estimates that it would need to charge utilities a total of $150,000,000, adjusted for inflation, annually, for 15 years based on enrichment services to date. Based on preliminary estimates from Duke, the Company recorded its share of the liability. A corresponding asset was recorded as nuclear fuel and is being amortized to nuclear fuel expense over the 15-year assessment period. The estimated remaining liability of $2,546,000 and $3,078,000 is included in the accompanying balance sheets in deferred credits and other liabilities at December 31, 2004 and 2003, respectively.

Power Coordination Agreements and Purchased Power Commitments

In 1996, the Company began receiving 205 megawatts (MW) of capacity from AEP. The agreement provides fixed capacity and energy prices through 2010.

In 1998, the Company negotiated a power supply agreement (PSA) and a network service agreement with CP&L which became effective January 1, 1999. Also in 1998, the Company entered into a purchased power agreement with CP&L for 800 MW of peaking capacity beginning in 2001 and extending through 2003. The Company also exercised the option to extend 800 MW through 2004. The Company has the option to extend 500 MW through 2005. The agreement provides fixed capacity and indexed energy prices.

In 2001, the Company entered into PSA's with AEP, VEPCO and South Carolina Electric and Gas Company (SCE&G) to supply a total of 970 MW of capacity. The term of these agreements is from 10 to 25 years. In 2003, the VEPCO PSA, which provided 570 MW of capacity from January 1, 2005, through December 31, 2029, was terminated and replaced with a 150 MW PSA with VEPCO from January 1, 2005, through December 31, 2014. In 2003, the Company also modified its PSA with CP&L to increase the amount of capacity purchased and to extend the terms for three of the capacity blocks it purchases from CP&L. The AEP agreement provides for fixed pricing. The VEPCO and SCE&G agreements provide for fixed capacity and indexed energy prices.

In 2002, the Company signed agreements with VEPCO, SCE&G and Southern Power Company (Southern) to purchase a total of 250 MW of peaking capacity and energy with load following capability for a two-year period beginning January 1, 2004. The agreements provide for fixed capacity and indexed energy prices.

In 2003, the Company negotiated a network service agreement with VEPCO which became effective January 1, 2004.

In 2004, the Company signed another agreement with CP&L for the purchase of 500 MW of capacity and energy in 2005, 750 MW in 2006, 450 MW in 2007 and 300 MW from 2008 through 2024. Also in 2004, the Company began taking transmission service from PJM Interconnection (PJM), due to the integration of the AEP transmission system into the PJM footprint. The Company expects that in 2005, its transmission service from VEPCO will become transmission services from PJM upon Virginia Power's integration into PJM.

In 2005, the Company signed an agreement with CP&L for the purchase of 100 MW of capacity from February 2005 through January 2006. The Company signed agreements with Progress Ventures and AEP each for the sale of 50 MW for the same period.

Plant Construction Agreement

During the mid-1990s, the Company purchased property, incurred licensing and architect fees and entered into an agreement to build a combined-cycle natural gas-fired electric generating plant. Construction of the plant was scheduled to begin in 1998. Due to changing power supply market conditions in 1996, the Company decided to delay the construction of the generating plant indefinitely. The Company has capitalized these preliminary project costs of $9,418,000 through December 31, 2004, in the accompanying balance sheets. The Company entered into an agreement with Dominion Davidson, Inc. to sell the property for approximately $12,000,000 conditional upon achieving certain milestones. In accordance with the agreement, the Company received $2,000,000 in 2002. In 2003, Dominion Davidson, Inc. terminated the agreement and forfeited the $2,000,000 previously paid to the Company. The Company has recorded this as a reduction to preliminary project costs at December 31, 2004, in the accompanying balance sheets.

Peaking Capacity Project

In 2004, the Company entered into an agreement with Pratt and Whitney Power Systems (PWPS) to build 620 MW of peaking capacity to be operational in 2007. In 2004, the Company submitted a loan request to RUS for an amount not to exceed $320,000,000 to finance the cost of the project. The Company expects the RUS loan to be approved and proceeds to be available in 2006.

In 2005, the Company entered into an agreement with NRUCFC for $75,000,000 of interim financing to fund the costs of the project prior to the time permanent financing is received from RUS. In addition, the Company requested a lien accommodation from RUS for interim financing for the project.

At December 31, 2004, the Company had capitalized $8,814,000 in costs associated with this project. These amounts are included in construction work-in-progress in the accompanying balance sheets. The Company is obligated to make payments of $12,700,000 in 2005 to PWPS per the terms of the contract.

Note J - Nuclear Insurance

Duke, acting on behalf of the joint owners of Catawba, maintains insurance coverage for public liability claims resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $300 million and a mandatory industry-wide excess secondary insurance program of risk pooling. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, the joint owners of Catawba could be assessed retroactive premium adjustments. The maximum assessment per reactor under the program for each nuclear accident is approximately $101 million, subject to an annual limit of $10 million per incident. Based on the Company's interest in Catawba, its maximum potential assessment per incident is approximately $28.3 million, with an annual payment limitation of approximately $2.8 million.

Duke maintains a Business Interruption Insurance Policy. This policy provides business interruption and/or extra expense coverage resulting from an accidental outage of a nuclear unit. Each unit is insured for up to $3.5 million per week.

Duke is a member of Nuclear Electric Insurance Limited (NEIL), which provides $500 million in primary property damage coverage for Catawba. If NEIL's losses ever exceed its reserves, the joint owners of Catawba will be liable for additional assessments. The potential maximum assessments are: Primary Property Insurance - $35 million, Excess Property Insurance - $44 million and Business Interruption Insurance - $29 million. Based on the Company's interest in Catawba, its maximum potential share of this assessment is approximately $10.9 million.

Duke also maintains insurance coverage for property damage to, and decontamination and decommissioning of, property at Catawba in the aggregate amount of approximately $2.3 billion. Duke has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of Catawba. The joint owners of Catawba are obligated to assume their pro rata shares of any liability for retrospective premiums and other premium assessments resulting from policies applicable to the joint ownership agreements.

Note K - Related-party Transactions

In accordance with a management agreement, the Company provides staff services to the North Carolina Association of Electric Cooperatives, Inc. (NCAEC), the Tarheel Electric Membership Association, Inc. and subsidiary (TEMA), TSE Services Inc. (TSE), EMC Technologies, LLC (EMCT) and the CEC Self Insurance Fund, Inc., (CECSIF), which are all related parties through common ownership. The management agreement provides that charges for these services include a component for general corporate expenses and an assessment for office space and computer equipment. The Company also charges the ElecTel Cooperative Credit Union (ElecTel), a related party, a fee for office space and use of the Company's copy machines. Charges to NCAEC were $4,947,000 in 2004, $3,876,000 in 2003 and $4,238,000 in 2002. Charges to TEMA were $2,579,000 in 2004, $2,429,000 in 2003 and $2,356,000 in 2002. Charges to TSE were $2,721,000 in 2004, $3,098,000 in 2003 and $3,784,000 in 2002. Charges to EMCT were $6,180,000 in 2004, $6,363,000 in 2003 and $7,636,000 in 2002. Charges to the CECSIF were $65,000 in 2004 and $40,000 in 2003 and 2002. Charges to ElecTel were $27,000 in 2004, $38,000 in 2003 and $30,800 in 2002.

The Company purchases various services from TSE, NCAEC and EMCT. Expenses related to services purchased from TSE totaled $1,315,000 in 2004, $1,269,000 in 2003 and $1,289,000 in 2002. Expenses related to services purchased from NCAEC totaled $2,953,000 in 2004, $2,086,000 in 2003 and $2,309,000 in 2002. Expenses related to services purchased from EMCT totaled $6,040,000 in 2004, $6,118,000 in 2003 and $7,620,000 in 2002.

In 2003, the Company reclassified $8,605,000 of the receivable from TSE to noncurrent receivables.

The Company has accounts receivable net of accounts payable with related parties at December 31, 2004 and 2003, as follows (in thousands). These amounts do not bear interest.

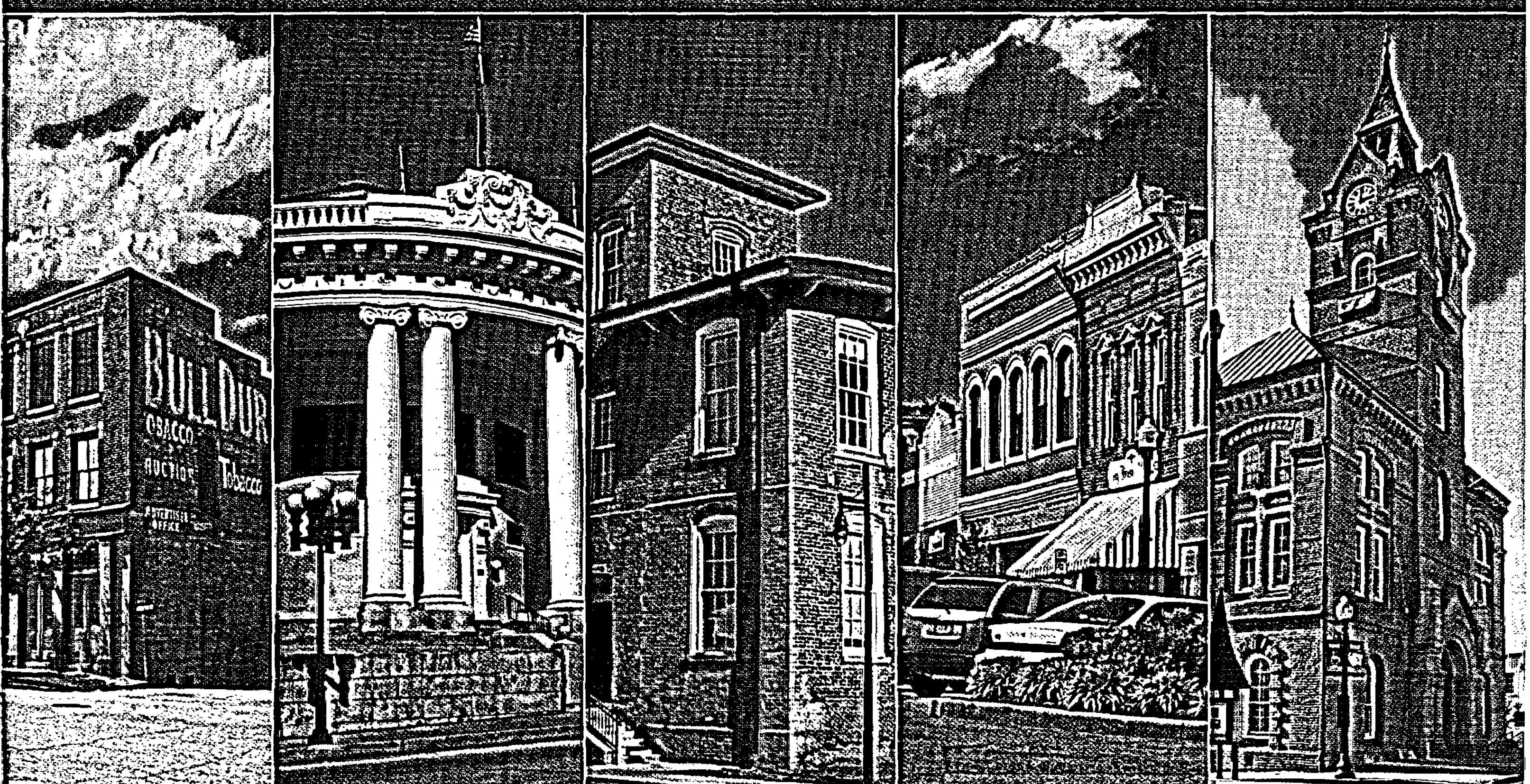
	2004	2003
Current:		
NCAEC	$ 168	$ 149
TEMA	219	417
TSE	166	144
EMCT	37	531
CECSIF	5	3
	595	1,244
Noncurrent:		
TSE	8,605	8,605
	$9,200	$9,849

The Company has designated $27,000,000 for loans to members for economic development and construction of customer-owned generation. At December 31, 2004 and 2003, outstanding loans totaling $8,436,000 and $9,605,000, respectively, have been included in accounts receivable and noncurrent receivables in the accompanying balance sheets. Economic development loans (totaling $8,433,000 and $9,569,000 at December 31, 2004 and 2003, respectively) do not bear interest and have repayment terms of up to seven years with an initial payment deferral of up to four years available under certain circumstances. Customer-owned generation loans (totaling $3,000 and $36,000 at December 31, 2004 and 2003, respectively) accrue interest at fixed and variable rates ranging from 1.9% to 8.3%. The repayment terms for these loans range from 1 to 7 years. The contractual maturities of the economic development loans and customer-owned generation loans described above are as follows (in thousands):

Years	Amount
2005	$1,758
2006	1,586
2007	1,483
2008	1,238
Thereafter	2,371
	$8,436

2004 ANNUAL REPORT

Responding Empowering Delivering

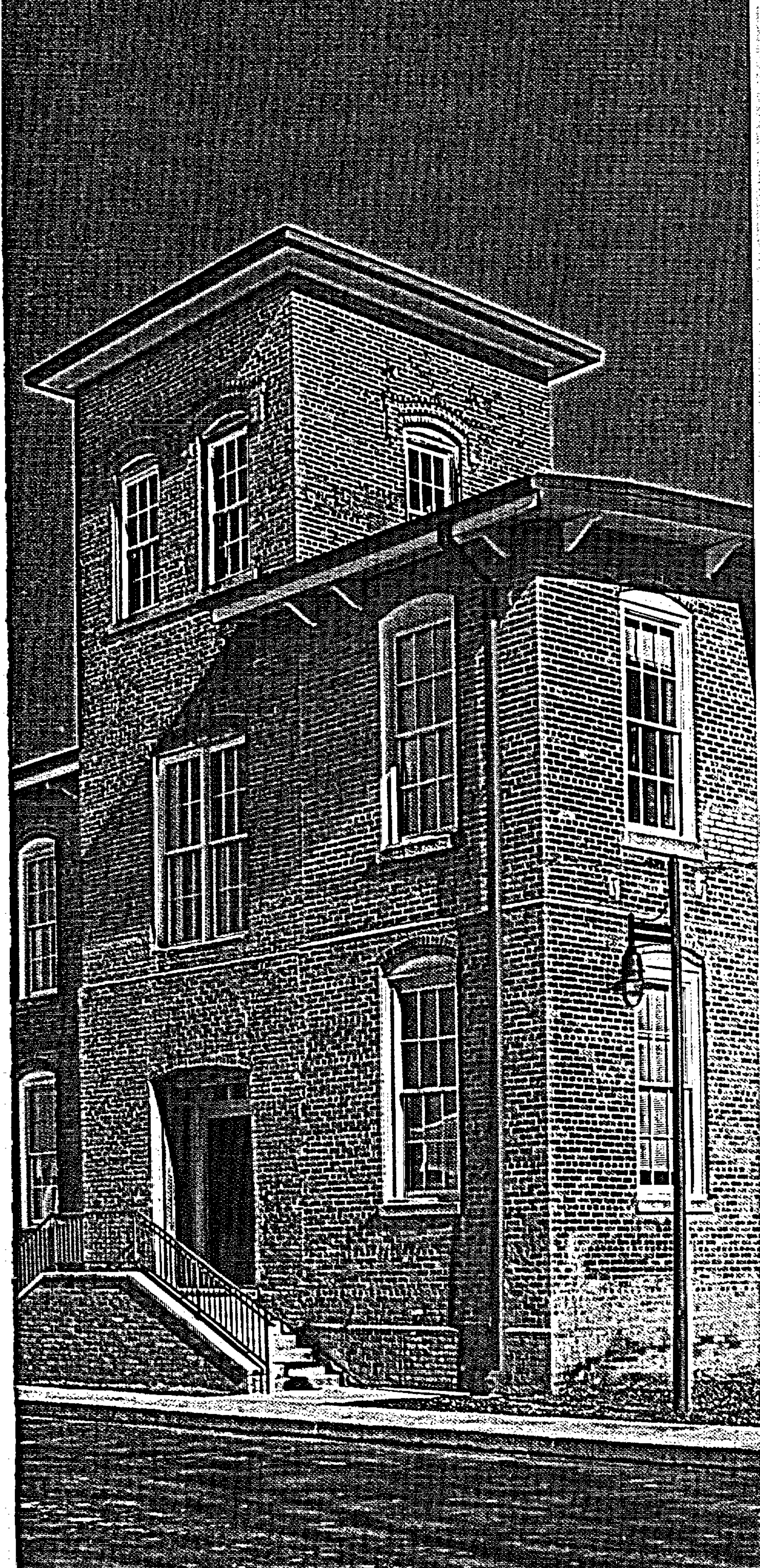


PIEDMONT MUNICIPAL POWER AGENCY

Contents

PIEDMONT MUNICIPAL POWER AGENCY

2004 ANNUAL REPORT



Piedmont Municipal Power Agency (PMPA) is a joint action agency formed by ten municipal electric utilities (Participants) in the northwest section of South Carolina. The Agency provides wholesale electric service through a 25 percent ownership interest in Unit #2 at the Catawba Nuclear Station, located in York County, South Carolina.

Management Letter

Board Chairman **Joel Ledbetter**, right & General Manager **Don A. Ouchley**

Today is a progressive time in the electric industry. Important decisions facing the industry are being considered by the United States Congress and the Federal Energy Regulatory Commission (FERC). During this time, PMPA is monitoring current issues in the electric industry and responding with solutions to the challenges we face. PMPA is empowering our Participants to be a force in these changes and help shape the future of the Agency. Likewise, PMPA is delivering results, through our partnerships with Members and our business partners, to ensure our future is secure.

Although a federal Energy Bill did not pass in 2004, and FERC was not able to implement major restructuring affecting transmission of electric power, the debate continues. PMPA is committed to ensuring that any changes made through restructuring efforts are in the best interests of our Members. Our continuing primary goal is to provide our Members and their customers with reliable electric power at prices that are affordable. Economic development in our cities is dependent upon having adequate, reliable and cost effective electric power. PMPA's ownership share in the Catawba Nuclear Station provides that reliable power source – for now and well into the future. We have begun a comprehensive program directed at stabilizing electric rates so that our Members may continue to grow and prosper in the years ahead.

In late 2004, recognizing the need to mobilize community leaders on a grassroots level to work with the South Carolina Congressional delegation, PMPA formed a Rate Reduction Team. The Team is comprised of city leaders and utility staff in our Member cities, along with state and federal legislators. The Team's purpose is to identify and pursue initiatives to accomplish PMPA's goals, specifically issues related to an amendment in the Department of Agriculture's Appropriations Bill. The amendment will allow PMPA to be fully eligible for grant and loan programs administered by the Rural Utilities Service (RUS). I am happy to report that the Team was successful, achieving approval of the amendment and making PMPA fully eligible for RUS loan and grant programs.

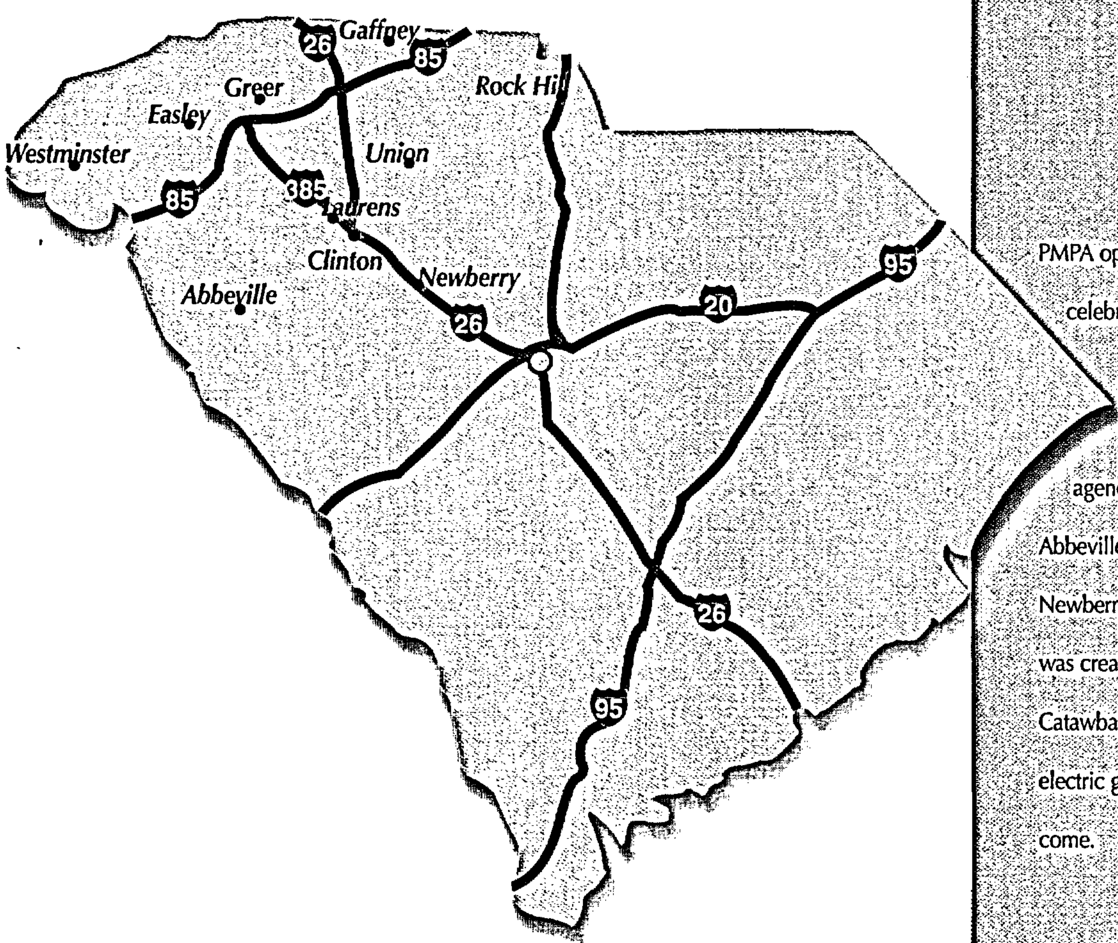
The Rate Reduction Team was formed around the idea of mobilizing community leaders in our Member communities to generate new ideas and achieve positive results. To date, new ideas and initiatives have been identified and are being pursued on an ongoing basis. Many of these initiatives involve federal agencies and require the support of our federal delegation to be successful. Among those ideas are requests to Congress for Members to receive federal appropriations for a variety of projects, including water treatment facilities, wastewater plants and highway projects. PMPA Members have been empowered to shape the future of our organization.

As a follow up to the license extension for the Catawba Nuclear Station in December 2003, PMPA seized the opportunity to extend and restructure our debt. This debt restructuring was a significant milestone in our rate stabilization initiative. While more work must be done to further stabilize rates, be assured that PMPA staff will deliver results in rate stabilization efforts.

We continue to progress toward our strategic goals, including our most important goal – **keeping power supply both reliable and cost effective.** With a resurgence of interest in nuclear power generation, our future is promising. The recent license extension at Catawba Nuclear Station offers a reliable, cost effective power supply for years to come.

Change is inevitable in the electric power industry. While all outcomes cannot be known, be assured that PMPA will continue to respond to emerging issues, empower city officials and staff to influence change and, ultimately, deliver quality leadership and reliable, cost effective power to our Member cities.

PMPA Cities



PMPA opened its doors for business in 1984 and celebrated a 20th anniversary in 2004. The non-profit agency was formed by ten municipal utilities in upstate South Carolina. The agency provides wholesale power to ten utilities: Abbeville, Clinton, Easley, Gaffney, Greer, Laurens, Newberry, Rock Hill, Union and Westminster. PMPA was created to purchase an ownership interest in the Catawba Nuclear Station, securing a reliable source of electric generation for member utilities for years to come.

PMPA Participants

Participants	Year Established	Revenues	Electric Customers	Percent Ownership
Abbeville Public Utilities	1905	$5,829,000	3,604	2.68%
City of Clinton	1907	$9,862,000	4,238	7.84%
Easley Combined Utilities	1911	$22,806,000	12,541	13.24%
Gaffney Board of Public Works	1907	$16,255,000	7,273	10.05%
Greer Commission of Public Works	1913	$22,787,000	15,308	9.34%
Laurens Commission of Public Works	1922	$8,578,000	5,194	6.49%
City of Newberry	1896	$13,341,000	4,866	10.47%
City of Rock Hill	1911	$59,276,000	29,677	28.04%
City of Union	1898	$12,674,000	7,046	10.01%
Westminster Commission of Public Works	1921	$2,908,000	1,592	1.84%
Total		$174,316,000	91,339	100.00%

Board of Directors

PMPA is governed by a 10-member Board of Directors. One Director and one Alternate Director are appointed from each member utility.

		Director	Alternate Director
Abbeville		***David Krumwiede*** City Manager City of Abbeville PO Box 40 Abbeville, SC 29620 864.459.5017	***Mark Hall*** Director of Public Utilities City of Abbeville PO Box 639 Abbeville, SC 29620 864.366.4518
Clinton		***Samuel Bennett*** City Manager City of Clinton PO Drawer 748 Clinton, SC 29325 864.833.7505	***Randy Randall*** Mayor City of Clinton PO Drawer 748 Clinton, SC 29325 864.833.7515
Easley		***Joel Ledbetter*** General Manager Easley Combined Utilities PO Box 619 Easley, SC 29641 864.859.4013	***Richard Gettys*** Retired Superintendent Pickens County Schools Easley Combined Utilities PO Box 619 Easley, SC 29641 864.859.4013
Gaffney		***Donnie Hardin*** General Manager Board of Public Works PO Box 64 Gaffney, SC 29342 864.488.8800	***Kim Fortner*** Operations Engineer Board of Public Works PO Box 64 Gaffney, SC 29342 864.488.8800
Greer		***David Duncan*** SC-DHEC Commission of Public Works PO Box 216 Greer, SC 29652 864.848.5500	***Jerry Balding*** General Manager Commission of Public Works PO Box 216 Greer, SC 29652 864.848.5500

Director | *Alternate Director*

Laurens

Coleman Smoak
General Manager
Commission of Public Works
PO Box 349
Laurens, SC 29360
864.984.0481

Dale Satterfield
Assistant General Manager
Commission of Public Works
PO Box 349
Laurens, SC 29360
864.984.0481

Newberry

Charles Guerry
Utility Director
City of Newberry
PO Box 538
Newberry, SC 29108
803.321.1018

Eric Budds
City Manager
City of Newberry
PO Box 538
Newberry, SC 29108
803.321.1000

Rock Hill

Nick Stegall
Utility Director
City of Rock Hill
PO Box 11706
Rock Hill, SC 29731
803.329.5519

Carey Smith
City Manager
City of Rock Hill
PO Box 11706
Rock Hill, SC 29731
803.329.7017

Union

Bruce Morgan
Mayor
City of Union
PO Box 987
Union, SC 29379
864.429.1700

Tommy Sherbert
Interim Utilities Director
City of Union
PO Box 987
Union, SC 29379
864.429.1721

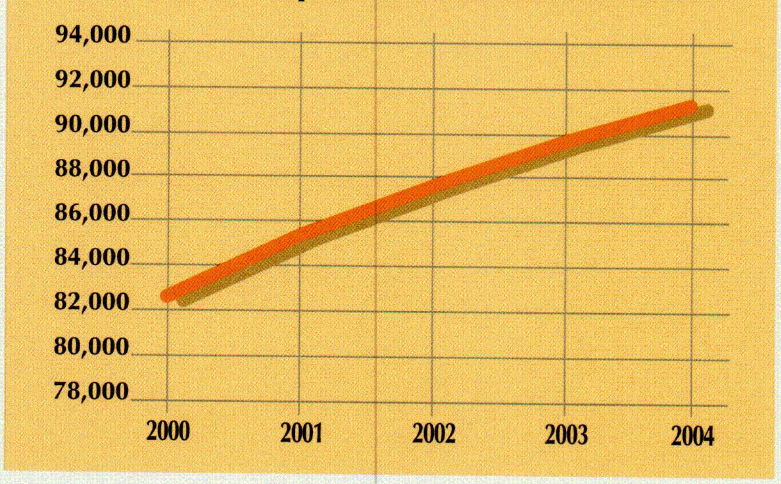
Westminster

David Smith
Utility Director
Commission of Public Works
PO Box 399
Westminster, SC 29693
864.647.3200

Jack Watkins
Retired US Postmaster
Commission of Public Works
PO Box 399
Westminster, SC 29693
864.647.3200

About PMPA

Since its inception in 1979, PMPA's member cities have shown consistent growth. Having weathered the national manufacturing recession of 2001-2003, the regional economy experienced more rapid expansion in 2004. With capital investment in the state growing in 2004 at twice the rate of the previous year, upstate South Carolina continued to diversify its economy and fill the employment gaps created by the contraction in traditional industries such as textiles. Access to an excellent transportation network and proximity to such rapidly developing hubs of commerce as Greenville, Spartanburg and Charlotte place member cities in a favorable position to continue to achieve their economic growth and development potential. Available, reliable and affordable electric power adds to the attractiveness of these locations. In combination with a progressive business environment, friendly and productive people and an unexcelled quality of life, the stage is set for the future success of PMPA members.

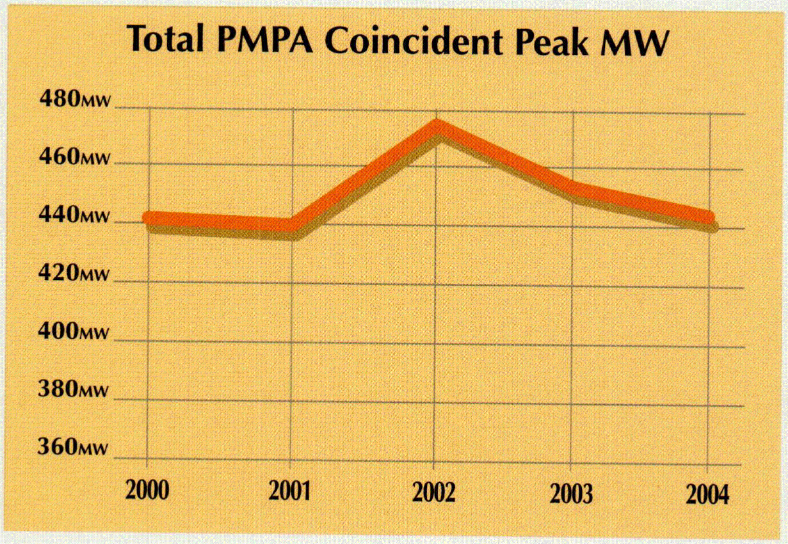


Total Participant Electric Customers

Total Participant Electric Customers

	2000	2001	2002	2003	2004
Total Participant Electric Customers	82,443	85,224	87,565	89,840	91,339
Total Participant Wholesale Purchases:					
PMPA Purchases (MWh)	1,992,616	1,944,545	2,059,950	1,935,037	2,047,661
SEPA Purchases (MWh)	75,831	76,965	80,140	156,301	136,674
Total Purchases (MWh)	2,068,447	2,021,510	2,140,090	2,091,338	2,184,335
Availability Factor					
Catawba 1	89.3%	99.6%	94.2%	81.8%	98.0%
Catawba 2	90.3%	85.7%	100.0%	92.7%	87.4%
McGuire 1	99.5%	88.0%	91.8%	100.0%	83.4%
McGuire 2	88.3%	99.3%	90.7%	91.6%	100.0%
Net Capacity Factor					
Catawba 1	90.0%	100.9%	95.9%	82.7%	97.9%
Catawba 2	90.6%	86.7%	102.9%	94.2%	89.1%
McGuire 1	103.4%	90.1%	94.4%	102.9%	85.3%
McGuire 2	87.5%	102.5%	92.5%	93.7%	103.4%

CO1



Total PMPA Coincident Peak MW

	2000	2001	2002	2003	2004
Total PMPA Coincident Peak (MW)	441	440	471	453	442

2004 Data	**Revenues**	**MWH's**	**Customers**
Residential	$80,596,412	855,668	79,369
Commercial	$83,264,744	1,022,113	11,806
Industrial	$8,091,491	130,855	47
Other	$2,363,246	34,391	117
Total	$174,315,893	2,043,027	91,339

PMPA member cities provide electric service to more than 91,000 residential, commercial and industrial customers. These local power systems belong to the people they serve and represent local consumers working together to meet local needs.

PMPA's Mission

PMPA will provide a reliable and sufficient supply of electricity to its members, seek viable opportunities to lower members' power supply costs, plan for future power supply requirements, safeguard assets while striving for maximum allowable returns, manage the Agency efficiently and effectively and be proactive in influencing and adapting to changes in the electric industry.

PMPA's Goal

At PMPA, our central goal is service to the ten cities we represent. PMPA is dedicated to improving the quality of life in each municipality as well as encouraging and fostering development and growth. PMPA is here because of these ten cities, and because of that, their citizens have the comfort of knowing that we are always just around the corner to help in any and every way we possibly can.

CO2

Abbeville

The cultural heritage of Abbeville is evident in its Historic District and its reputation as the birthplace and deathbed of the Confederacy. The tree-lined town square with its Charleston-style architectural features accommodate the Abbeville Opera House, the County Courthouse and a variety of businesses catering to the needs of natives and tourists. Restoration and revitalization of its downtown district has received national recognition.

Together with its emphasis on history and recreation, the city has a diversified economic base with a combination of traditional and contemporary business and industry. In addition to the quality of life factors, the area offers a low cost of living, an abundant water supply, modern telecommunications access, an attractive labor market, a variety of fully-served, reasonably-priced business sites and a dependable and affordable supply of electrical energy. Quality schools and health care facilities round out a complete complement of community services.

Providing electric service to the community since the early 1900s, Abbeville continues to maintain and expand its electric service capabilities to meet the needs of the community. In 2004, service was extended to a new hospital and wellness center under construction on property annexed by the city and to a new baseball complex adjacent to a newly constructed middle school. The medical center project is expected to be one of the largest employers in the county and will be the catalyst for the location of a number of new health service businesses. System enhancements during the year include continuation of the Streetscape Improvement Project and improvements along the Highway 72 Corridor. Highway 72 is in the process of being widened from the state line to Interstate 26 at Clinton to offer an alternative route to Atlanta.

Abbeville Electric Customer Data

	2000	2001	2002	2003	2004
Total Customers	3,619	3,634	3,643	3,596	3,604

2004 Data	Revenues	Customers
Residential	$3,125,000	3,103
Commercial	$2,704,000	501
Total	$5,829,000	3,604

	Coincident Peak	Non-Coincident Peak
System Demand (KW)	11,628	14,556

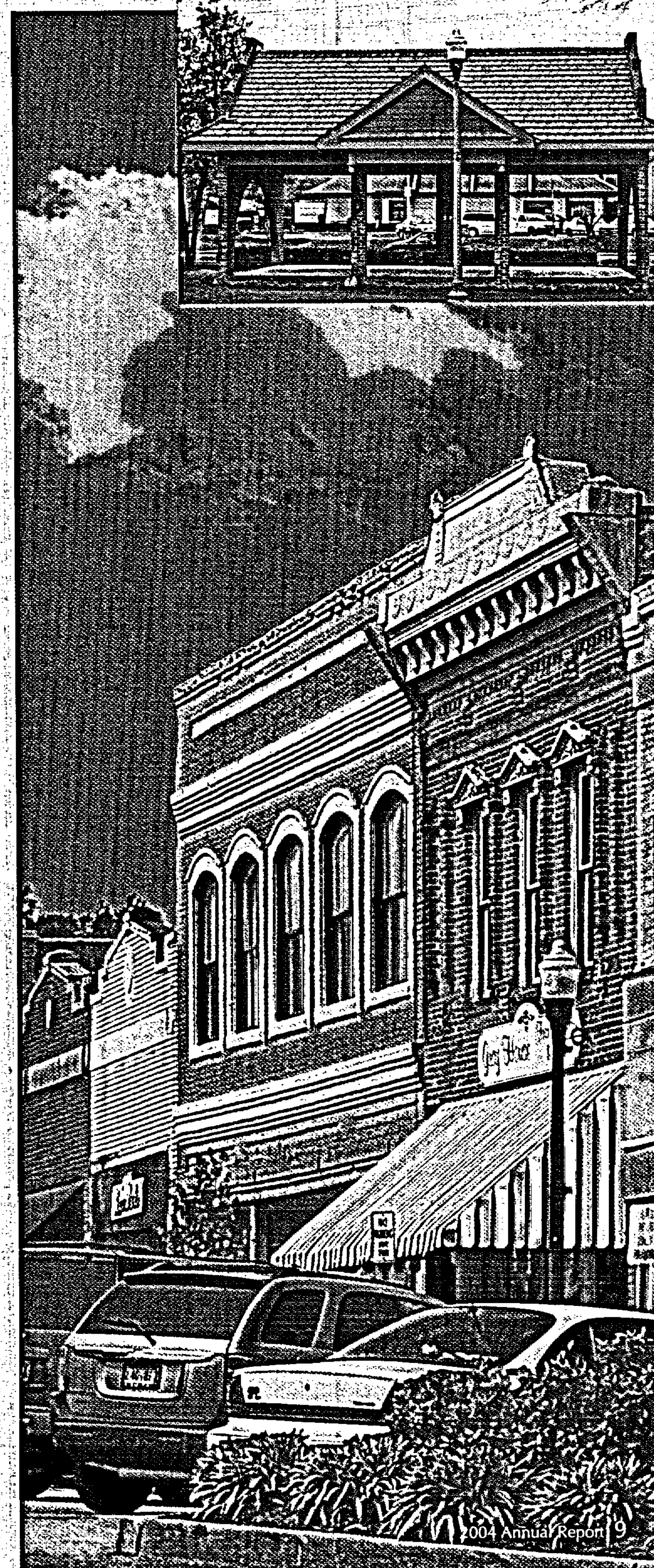
City Manager, David Krumwiede, (left) and Director of Public Utilities, Mark Hall, stand outside the historic Abbeville Opera House.

Internet visitors can view events in the town square via "web-cam".

Clinton

The city of Clinton, with approximately 10,000 residents, is the second largest city in Laurens County. Because of its interstate connections and railroad access to industrial clusters, research centers, suppliers and markets, Laurens County has had considerable success in attracting investment in manufacturing and distribution activities to replace a deteriorating textile sector. Strategically positioned at the intersection of Interstate Highways I-385 and I-26, Clinton is a progressive, growing community within an easy drive of the metropolitan centers of Columbia and Greenville/Spartanburg. A promising industrial park, ClintonPark Corporate Center, at the intersection of SC 72 and Interstate 26, will serve as an attractive economic gateway to the city. The local economy continues to become more modern and diversified as evidenced by new jobs and plant investment during 2004 in high-tech automotive bearings and plastics products for the home. At the same time, the city is working to preserve and enhance the many features that exemplify its traditional, small-community atmosphere by continuing to breathe new life into its historic downtown business district and surrounding neighborhoods.

The city serves over 4,000 electrical customers through its Combined Utility System. The system has a long and distinguished record for service quality and reliability. Dating back to 1907, the system has been an integral part of the growth and development of the community. Its commitment to progress and service is reflected in its role in Clinton's business and economic development, downtown revitalization, neighborhood restoration and cultural preservation. In 2004, the main investments of resources were focused on system upgrades and maintenance. New service extensions and upgrades were accomplished in residential areas as well as for new retail and service sector customers. The system is constantly anticipating and preparing for changes by maintaining system infrastructure and equipment, ensuring adequate capacity and dependability, and implementing operational efficiencies to provide quality services.



Clinton Electric Customer Data

	2000	2001	2002	2003	2004
Total Customers	4,243	4,398	4,532	4,189	4,238

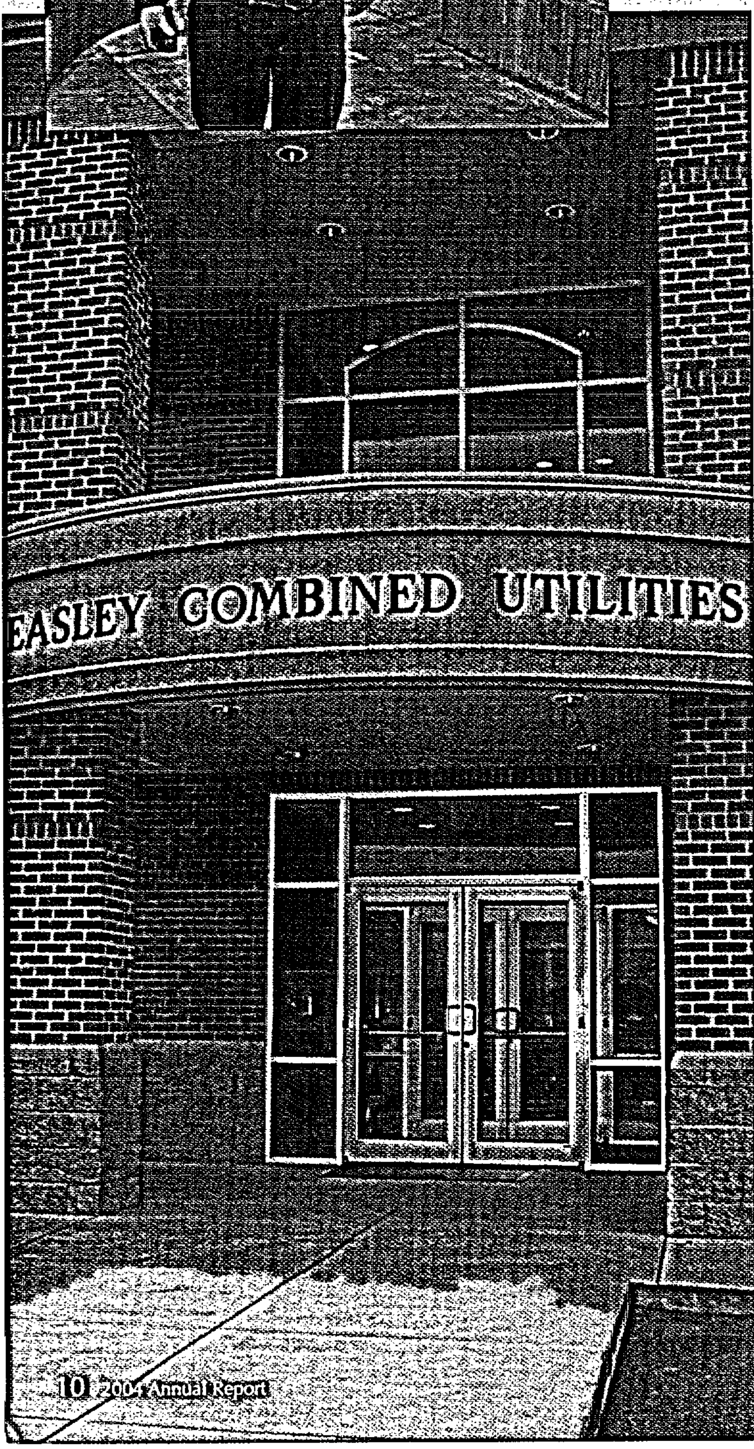
2004 Data	Revenues	Customers
Residential	$3,689,000	3,615
Commercial	$3,927,000	617
Industrial	$2,246,000	6
Total	$9,862,000	4,238

	Coincident Peak	Non-Coincident Peak
System Demand (KW)	24,254	25,315

Downtown Clinton is pedestrian friendly.

A replica of the roofline of the original depot serves as the focal point for downtown activities and events.

Easley



A few years after the railroad route between Charlotte, NC and Atlanta, GA was decided in 1870, the legislature ratified the Charter of Easley Station at a site along the rail line one mile north of Pickensville, in Pickens County. In 1901, the Charter was changed to create the City of Easley. Located in the northwestern corner of the state in the foothills of the Blue Ridge Mountains, Pickens County encompasses numerous lakes and streams, beautiful mountain vistas, and a fine quality of life with a rich heritage. Easley is now the largest city in the county with a population of approximately 18,000. Less than 10 miles from the I-85 corridor, Greenville and Clemson lie within a 30-minute drive and Charlotte and Atlanta are only two hours away.

As the presence of the textile industry has declined over the years, the Easley economy has become more modern and diversified. The city has benefited by the growth and attraction from the new and expanded industry attracted to the "upstate" area's business climate and quality of life. Abandoned mills along Main Street have been converted to small business and warehouse space. Other renovations, such as the conversion of the old high school building into condominiums, are creating new residential units and new neighborhoods are emerging. Retail services are expanding along the highway corridors in and near the city.

Providing a reliable supply of water, wastewater and electric service at the best possible price has been a community tradition since 1911. The first electricity generated was used to supply power to the water treatment plant and the initial distribution system supplied electricity to the city's downtown area. The Combined Utility System was created in the early 1950's, bringing together the administration of the expanding electrical network with the city's water system. Sewage collection became part of the combined system a few years later. Today, the electric system has a base of over 12,500 customers, 87 percent of which are residential. A peak shaving generation facility constructed in Easley takes pride in maintaining its commitment to providing reliable and affordable services to maintain the city's vitality and the quality of life enjoyed by its present and future citizens.

Easley Electric Customer Data

	2000	2001	2002	2003	2004
Total Customers	11,910	12,340	12,535	12,368	12,541

2004 Data	Revenues	Customers
Residential	$12,302,000	10,850
Commercial/Ind	$10,504,000	1,691
Total	$22,806,000	12,541

	Coincident Peak	Non-Coincident Peak
System Demand (KW)	59,163	63,202

Kip Deck, ECU Purchasing Agent, stands in Easley's new high-service pumping station.

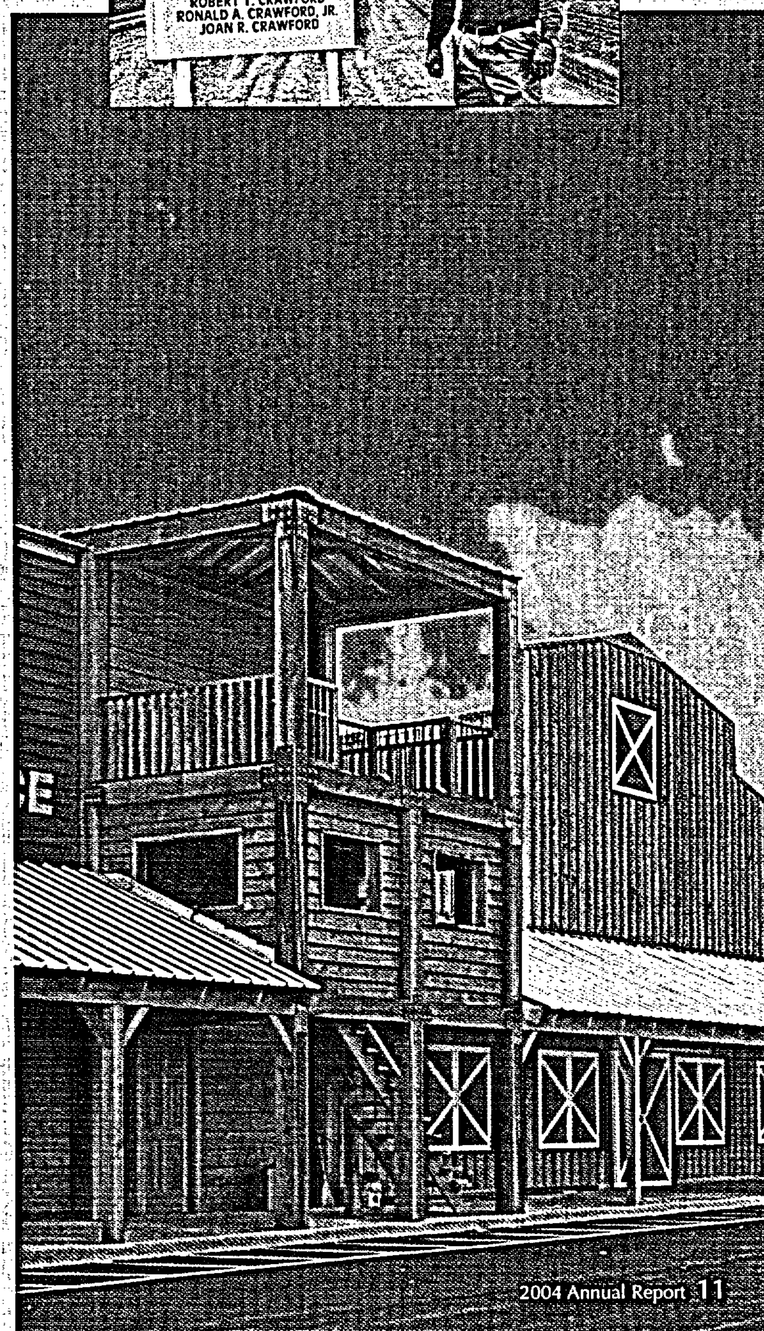
Easley Combined Utilities began serving customers from its new office in November 2002.

Gaffney

Gaffney is the county seat of Cherokee County noted historically as the site of the Battle of Cowpens in 1781, an important victory for the revolutionary forces. In the foothills of the Appalachian Mountains in northwestern South Carolina, Cherokee County borders North Carolina in a region where iron mining was important until the time of the Civil War. In the mid-19th century, the Gaffney area was the location of the Limestone Springs resort, a popular retreat for Low-country planters. As the town grew, the resort hotel was converted into a school for women, now Limestone College. Gaffney was incorporated in 1857, and named for pioneer merchant Michael Gaffney. Growth was given a boost with the introduction of the railroad in 1873 and the town developed around an economy based on textiles and cotton.

Currently home to nearly 13,000 residents, Gaffney lies beside Interstate 85, strategically positioned between Charlotte, NC and the Greenville/Spartanburg area. It is ideally situated for individuals and businesses seeking a suburban setting with quick and easy access to large urban development and metropolitan markets. The economy has undergone significant changes as traditional goods and services have given way to a more diversified business and industry base. Peaches have become the area's primary agricultural commodity and Gaffney has hosted the annual South Carolina Peach Festival, now a two-week event, since 1961. New retail and industrial growth has brought new job opportunities, particularly along the I-85 corridor. The commercial and industrial development has been followed by growth in retail, educational services, government, and health services. To support current and potential development in the area, a new technical training facility is planned to equip the local workforce with the skills necessary to attract and sustain the new and emerging business activity.

Since 1907, the Public Works Board has supported the community and its development through reliable, efficient and affordable water, sewer, and electrical service to Gaffney and the surrounding areas of Cherokee County. Through the years, the Board has expanded and upgraded its systems and services, and currently provides electricity to nearly 7,300 customers through approximately 130 miles of lines.



Gaffney Electric Customer Data

	2000	2001	2002	2003	2004
Total Customers	7,346	7,342	7,296	7,260	7,273

2004 Data	Revenues	Customers
Residential	$5,721,000	6,044
Commercial	$7,569,000	1,179
Industrial	$1,491,000	27
Other	$1,474,000	23
Total	$16,255,000	7,273

	Coincident Peak	Non-Coincident Peak
System Demand (KW)	41,958	42,643

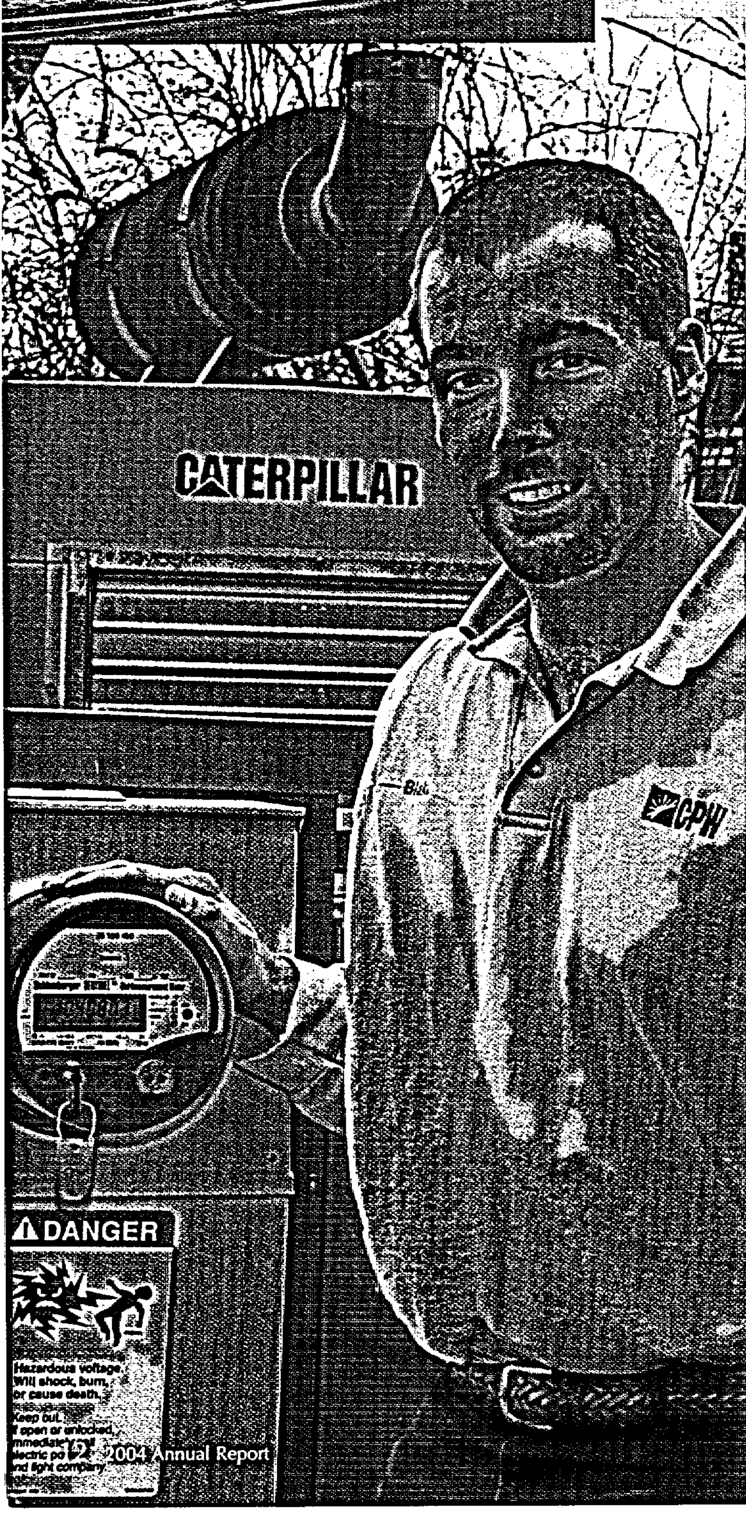
Mike Bolin, GBPW Safety Coordinator, stands at the entrance to the new Cherokee County campus of Spartanburg Technical College.

The new Towne Shoppes retail center is the venture of a local entrepreneur with remarkable success in the shoe business.

Greer

Greer resides in Greenville County in the northwestern corner, or "Upstate", of South Carolina. Nestled in the foothills of the Blue Ridge Mountains, the region's rolling hills with an abundance of lakes, streams and rivers were part of the Cherokee Nation prior to the Revolutionary War. The land was acquired by the State shortly after the war and sparsely settled until the arrival of the railroad in 1873. As this area of intrinsic natural beauty developed over the decades into a major transportation corridor, it became a hub of commerce. Major air, rail and highway routes between Charlotte, North Carolina and Atlanta, Georgia traversed the area, and travel to the Port of Charleston was facilitated by the construction of an interstate to the southeast. With ready access to the markets of the nation and the world, the region has been transformed from an economy originally dominated by farming and textile manufacturing into a region providing headquarter locations for various industries, a center for a variety of high-tech manufacturing enterprises, and a warehousing center for regional distribution activities.

From its modest beginnings as a trading post in 1876, Greer has grown into a vibrant city with a booming economy. Recognized as one of the State's fastest growing cities over the past decade, Greer has a current population in excess of 20,000. Midway between the cities of Greenville and Spartanburg, the city is located in a region that has become well-known for its high-technology manufacturing growth. As a result, Greer has been successful in attracting a highly-diversified manufacturing and industrial base with a strong international influence. Its excellent transportation infrastructure has made it an ideal location for services, warehousing and distribution activities. The success of its industrial and commercial growth has created a major expansion in the retail sector. The city has been strategically positioned to capitalize on the surrounding development, yet it strives to maintain the appeal and quality of life that has distinguished it from other larger urban areas. Greer's Partnership for Tomorrow focuses on downtown revitalization and balances historical preservation with new residential and commercial development around the community-oriented plazas and parks. First-rate schools, health care and recreational facilities round out the community services that help build a strong hometown identity, civic pride and an exceptional quality of life.



Greer Electric Customer Data

	2000	2001	2002	2003	2004
Total Customers	10,992	11,544	12,333	14,341	15,308

2004 Data	Revenues	Customers
Residential	$12,917,000	13,584
Commercial	$9,196,000	1,692
Other	$674,000	32
Total	$22,787,000	15,308

	Coincident Peak	Non-Coincident Peak
System Demand (KW)	59,861	61,299

A new outpatient surgical center offers Greer's residents additional options for quality medical care.

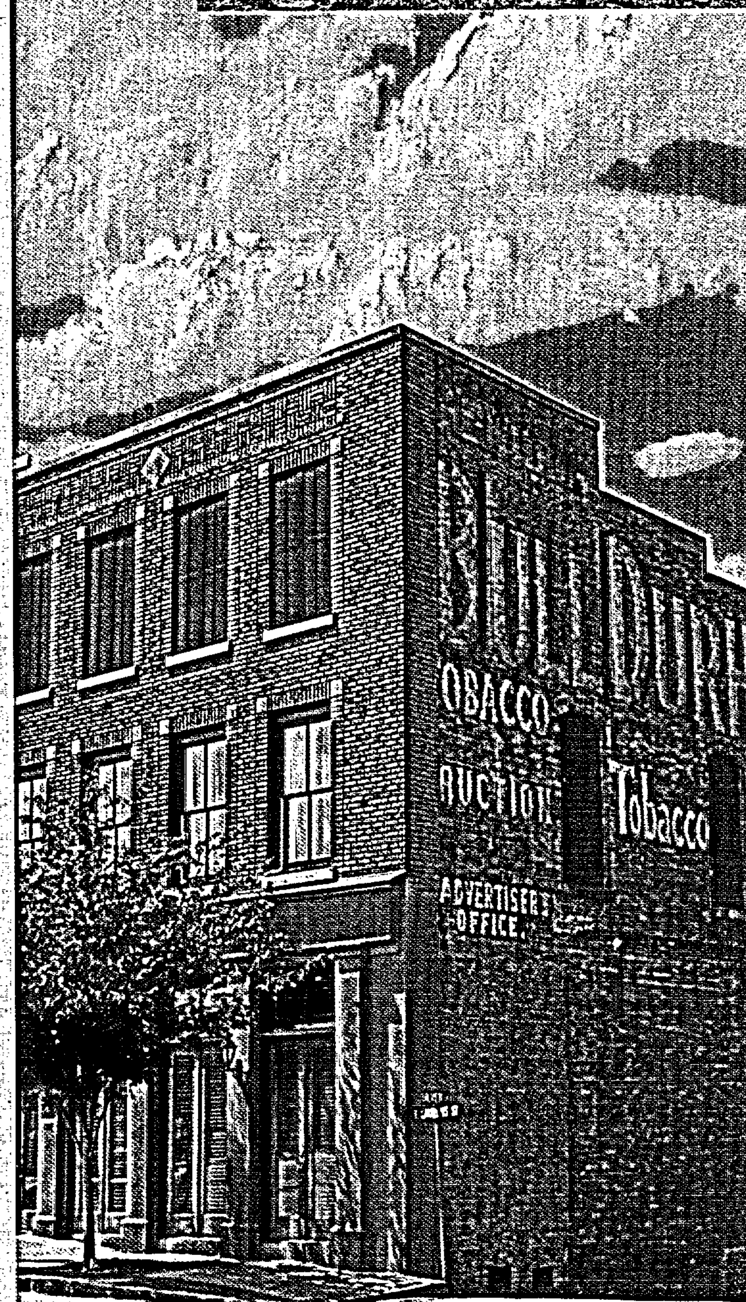
Blake Barbare, Warehouse Supervisor, stands by a meter used with Greer's new automated meter reading program which underwent a major expansion in 2004 offering a less intrusive and more cost efficient meter-reading process.

Laurens

Laurens is home to 10,000 residents who take pride in their community and its heritage, diversity and potential for growth and development. In the city and surrounding areas, textile dominance has been displaced by a wide variety of industrial activity that includes plastics, ceramics, automotive and other advanced manufacturing/metalworking operations. The city has been successful in attracting its share of the area's manufacturing growth with resources such as the Hunter Industrial Park, at the intersection of I-385 and US 221, which had two plant expansions announced in 2004. With this industrial growth has come expansion in the retail and services sectors.

The Laurens Commission of Public Works (CPW), a publicly-owned, not-for-profit utility providing reliable and affordable electric service to the community, has been operating since 1922. The Laurens CPW is a major player in the city's growth and development and is well-respected for its role in support of community activities. In 2004, the CPW provided essential logistical support to the production of a nationally-televised project to revitalize the downtown district. It joined with television network production crews and volunteers from around the community to ensure the success of the renovation efforts that have brought a great deal of national attention to the city and its people. Six episodes of the series featuring Laurens, "Town Haul", are scheduled to run for six weeks on The Learning Channel in early 2005. In addition to the logistical involvement and hours of volunteer work on this important project, the CPW staff invested considerable time and money during the year on system upgrades to affect cost savings and even greater system dependability. Upgrades in the computer system to monitor and control system operations across municipal functions have improved telecommunications capabilities and added Internet access.

With the many appealing features that characterize the city as an attractive place to live and work and the national exposure gained via its media attention, Laurens is in position to receive an increasing number of business inquiries and interested visitors.



Laurens Electric Customer Data

	2000	2001	2002	2003	2004
Total Customers	5,313	5,297	5,290	5,216	5,194

2004 Data	Revenues	Customers
Residential	$4,591,000	4,352
Commercial/Ind.	$3,987,000	842
Total	$8,578,000	5,194

	Coincident Peak	Non-Coincident Peak
System Demand (KW)	22,847	23,081

A new children's park was one of the major projects completed as part of the televised "Town Haul" series.

The TV production workers repainted some old, faded signs to retain their sense of history in the downtown revitalization effort.

Newberry

Combining antebellum mansions and tree-lined streets with a progressive attitude for economic development, Newberry can be characterized as a dynamic blend of the old and the new. With a population over 10,000, it is the largest city in the county and is recognized as one of the safest places to live in the state. The city lies adjacent to Interstate 26 which has served as the catalyst for investment in modern, more diverse industrial and commercial activity. The main highway connectors linking the interstate with the central business district have experienced significant commercial development. The downtown area, with its historic buildings and architectural features, remains a vital focus of business, education, government and cultural activity. The result is a mix of active retail and service centers interspersed with quiet, quaint neighborhoods containing many beautiful, historic homes. The city serves as the county's service center for health care, education, culture and recreation.

The community's business and residential electric power needs are supplied by the city's utility department. In 2004, the city's utility crews and staff continued to improve the availability and reliability of high quality, dependable, and affordable electrical power. In addition to the routine system upgrades and maintenance, a number of new investment projects have required their attention, including a new city conference center, downtown lighting and service improvements, new retail development along the SC 219 corridor, and the renovation of the old hospital to create housing for the low-income elderly. The expansion of the city's fiber optic network to provide high-speed connectivity between municipal buildings has facilitated the delivery of city services, quickened response times, and provided cost savings. The utility department continues to do its part in the growth and development of the community, and in the preservation and enhancement of the quality of life.

Taking all of its many attractions and resources into account, it's simple to understand Newberry's high national rankings on lists of the most appealing and livable small towns in America.

Newberry Electric Customer Data

	2000	2001	2002	2003	2004
Total Customers	4,800	4,789	4,774	4,790	4,866

2004 Data	Revenues	Customers
Residential	$3,908,000	4,002
Commercial	$5,079,000	850
Industrial	$4,354,000	14
Total	$13,341,000	4,866

	Coincident Peak	Non-Coincident Peak
System Demand (KW)	26,076	36,393

Newberry's Opera House is a focal point of the downtown restoration efforts.

Rock Hill

From its modest beginnings, Rock Hill has become the largest city in York county and South Carolina's fifth largest with a population of more than 56,000. The city's close proximity to the I-77 corridor and the Charlotte, NC metropolitan area makes it an ideal location for development. Accessible to the country's fifth largest trade area, approximately five million people are within a 100-mile radius. High-amenity industrial parks facilitate the location and expansion of diverse, modern business and industry. The city is also noted for its service and retail development, medical facilities, parks and recreation areas, and, cultural attractions. The heart of the city is undergoing a renaissance centered on a mixed-use activity center surrounded by linked neighborhoods. In blending the old with the new, the redevelopment includes the renovation of abandoned mills, the preservation of historic housing, and the restoration and reuse of other historic structures. The plan encompasses the campus of Winthrop, now a University of more than 5,500 students.

The city owned and operated combined utility system has been providing electric service since 1911. Rock Hill Utilities serves its customers with a focus on community responsibility, resource adequacy and reliability. Through a comprehensive planning and budgeting program, system administrators fund and execute the maintenance and new capital investments necessary to ensure that these objectives are met. Included in the expansions and upgrades for 2004 were multiple projects, including: the widening of Cherry Road to convert overhead lines to underground, improving appearance and reliability; expansion of the fiber optic network for better communication and control; replacement of dated equipment to match modern standards of operational efficiency; various lighting projects, including those at I-77 intersections; modernization of traffic signals and controls; and new service connections at locations such as the Rock Hill Tennis Center and the Highland Park Mills senior housing project.

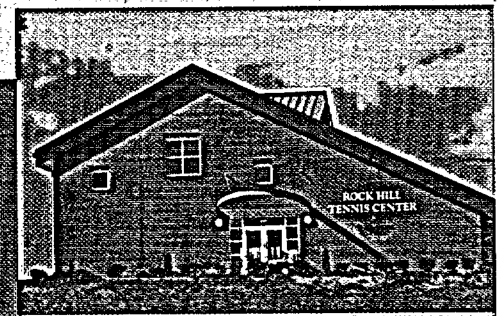
All the ingredients are in place for continued growth and development in Rock Hill, and for further enhancements of its exceptional quality of life. Care in the planning and development of the electric infrastructure will help support the realization of the high expectations for the future.

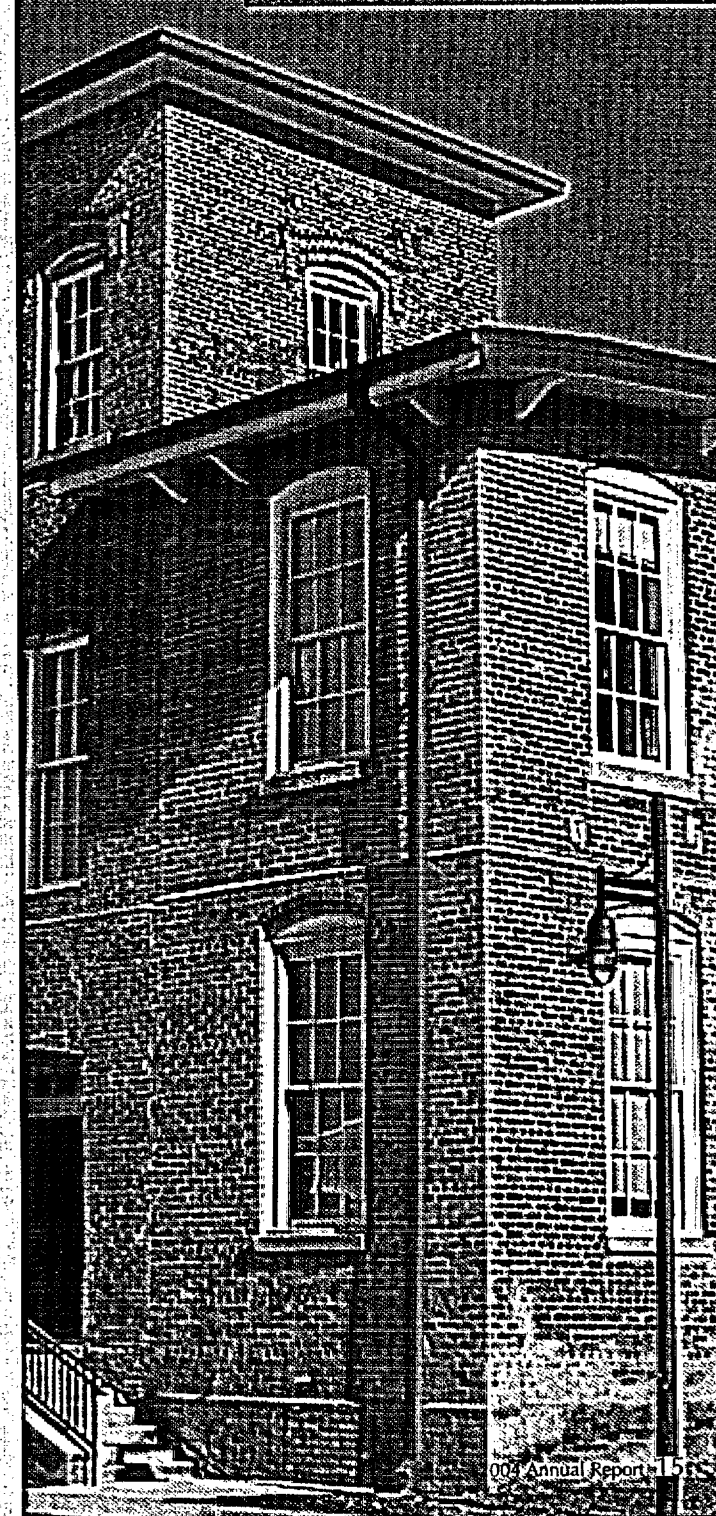
Rock Hill Electric Customer Data

	2000	2001	2002	2003	2004
Total Customers	25,463	27,117	28,417	29,347	29,677

2004 Data	Revenues	Customers
Residential	$26,081,000	26,458
Commercial/Ind.	$33,194,000	3,219
Total	$59,275,000	29,677

	Coincident Peak	Non-Coincident Peak
System Demand (KW)	161,345	163,620

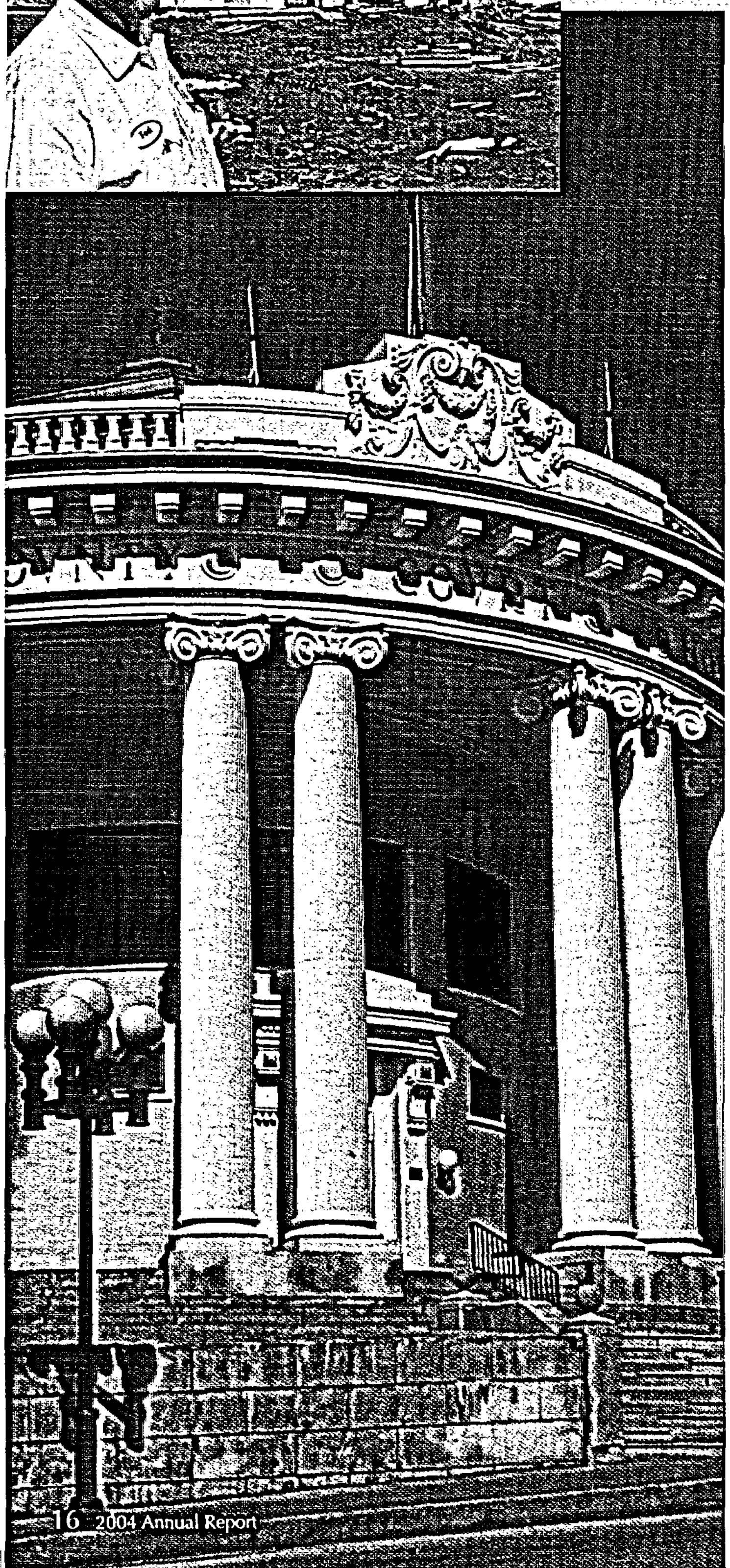




Rock Hill's new tennis center provides recreation opportunities for citizens.

Highland Park Mills, a new community for seniors, creates an efficient new use for an old textile mill.

Union



Though residents of Union enjoy the environmental benefits, leisurely pace, and small-town appeal afforded by the area, they are within an hour's drive of three major metropolitan areas: Greenville, Spartanburg, and Charlotte. Since 1991, US highway 176 has provided a four-lane connection to Spartanburg and the rapid development along Interstate 85. SC highway 49 links Union to I-26 and I-385 providing access to Greenville, Columbia, and the port of Charleston. These economic corridors provide new industrial prospects a connection with the city of Union and the county's hundreds of acres of greenfield sites, industrial parks, and available buildings. With the decline in textile employment, the area has an ample supply of skilled labor noted for their strong work ethic. As a progressive community with a high quality of life and a low cost of living, Union has all the resources necessary to attract and sustain new growth and development.

Union is the largest city in Union County with a population of approximately 8,500. The local economy has suffered some setbacks from the decline in textile employment. However, the outlook has improved with the announcement that a private company has purchased, and plans to reopen, a closed finishing plant. More new investment is likely since current economic conditions qualify the city, and the county, to offer the full range of available state and local industrial location incentives.

The electric division of the Utility Department operates and maintains the city's electric distribution system and serves over 7,000 customers effectively and efficiently both inside and outside the corporate limits. With minimal expansion pressure in 2004, system activities were focused on operations and maintenance. Plans for a new generator were finalized to help meet peak load demands and help control costs. New lighting and wiring projects were undertaken in the downtown area as part of a major revitalization effort. Equipment replacement, and substation and right-of-way maintenance projects were accomplished to improve the quality and dependability of the electric power infrastructure. Family apartments, under construction at the site of old Union Mill, and new retail development created new service opportunities.

The city of Union and its utility services continue to uphold the service commitments and quality operations that have served the community so well in the past. They also look forward to the promise of the future with confidence, strength of purpose, and renewed optimism.

Union Electric Customer Data

	2000	2001	2002	2003	2004
Total Customers	7,057	7,092	7,097	7,071	7,046

2004 Data	Revenues	Customers
Residential	$6,785,000	5,968
Commercial/ Ind.	$5,674,000	1,016
Other	$215,000	62
Total	$12,674,000	7,046

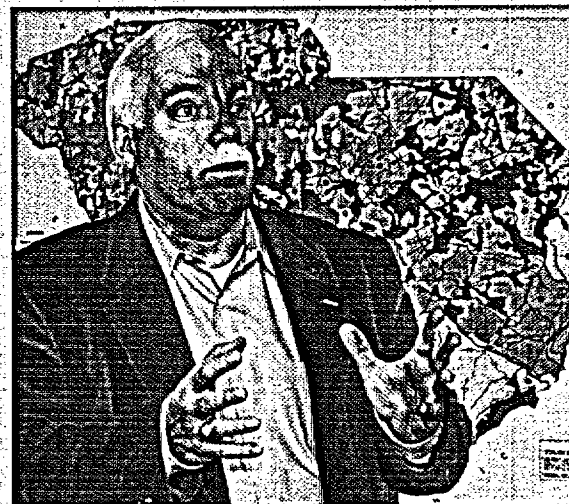
	Coincident Peak	Non-Coincident Peak
System Demand (KW)	29,154	29,419

Ted Adams, Electrical Supervisor, stands at the site of new family apartments.

The striking architecture of the county courthouse anchors the historic downtown area.

Westminster

Centered in the largest apple-producing area of the state, Westminster was selected as the site of the South Carolina Apple Festival which has drawn thousands of visitors to the area since 1961. Westminster has over 100 homes that reflect turn-of-the-century architecture.



The Westminster Commission of Public Works began serving the community in the early 1920's and provides a reliable and affordable complement of electrical services to residences and businesses. While recent employment losses have proven to be a challenge to maintaining system demand, the economy has remained resilient, with usage stabilizing. Maintenance and system improvements have continued as the structure of the town's utility services has been undergoing a significant realignment. The organization of the utility function is under review and will likely be changed to accommodate a new management and leadership structure. Renewed emphasis is being placed on defining core values, program direction and strategies followed by a reformulation of policies and procedures. This restructuring is expected to result in a service mechanism better suited to meet the current needs of the community and the challenges of the future.

Meanwhile, system modernization projects, such as the conversion of mercury vapor street lights to high-pressure sodium lights, are being conducted. New policies, programs and products will result in greater innovation and improved efficiency of operation as the town prepares to seek new avenues to support growth and development. Strategic planning will focus on emerging areas of customer demand such as the potential offered by the growing area of heritage and nature-based tourism. In an area so blessed with attractive natural resources and an outstanding quality of life, the future looks bright indeed.

Westminster Electric Customer Data

	2000	2001	2002	2003	2004
Total Customers	1,700	1,671	1,648	1,662	1,592

2004 Data	Revenues	Customers
Residential	$1,477,000	1,393
Commercial	$1,431,000	199
Total	$2,908,000	1,592

	Coincident Peak	Non-Coincident Peak
System Demand (KW)	6,165	6,831

David Smith, CPW Utility Director, explains changes that are underway in Westminster.

Renovation efforts hope to preserve the vitality of the downtown retail district.

Operational Highlights

PLANT INFORMATION

	Capacity Factor *	Availability Factor *
Catawba Unit 1	97.9%	98.0%
Catawba Unit 2	89.1%	87.4%
McGuire Unit 1	85.3%	83.4%
McGuire Unit 2	103.4%	100.0%

* These numbers are reported by Duke Power Company to the Nuclear Regulatory Commission in the Units' December 2004 Operating Data Report.

Catawba Unit 1 was running for all of 2004 with no scheduled refueling outage. The next refueling outage for Unit 1 is scheduled to begin in May 2005.

Catawba Unit 2 began a refueling outage on September 11, 2004 that ended on October 24. The unit completed a record continuous run of 531 days – the longest for any nuclear unit on the Duke Power system. The next refueling outage is scheduled for March 2006.

McGuire Unit 1 began a refueling outage on March 6, 2004 that ended on April 12. The unit completed a continuous run of 512 days. The next refueling outage is scheduled for September 2005.

McGuire Unit 2 began a refueling outage on March 1, 2005 that is projected to end on April 7. The unit completed a continuous run of 506 days.

Plant License Extensions

Duke requested License Extensions from the Nuclear Regulatory Commission (NRC) for both the McGuire and Catawba Stations in June 2001. The NRC issued new operating licenses for the McGuire and Catawba Units on December 5, 2003. The operating licenses are extended as follows:

Catawba Unit 1	December 2043
Catawba Unit 2	December 2043
McGuire Unit 1	June 2041
McGuire Unit 2	March 2043

Security

Following the 2001 terrorist attacks on the World Trade Center and the Pentagon, the nation's nuclear power plants came under scrutiny as potential targets. As a result, nuclear power plants upgraded security measures. Under the contractual arrangement with PMPA, all issues of security are handled by Duke Energy. Duke coordinates closely with federal, state and local authorities and continues to take appropriate steps to ensure safety and security at Catawba Nuclear Station.

Financial Highlights

INVESTMENT PORTFOLIO STATISTICS
(Dollars in $000s)

Earnings Information

	Income	Rate of Return
2004	$ 14,582	4.07%
2003	$ 15,225	3.91%

Market Value/Average Maturity as of 12/31

	Market Value	Average Maturity
2004	$ 356,173	2.1
2003	$ 422,459	2.6

DEBT OUTSTANDING
(Dollars in $000s)

Bonds Outstanding	
12/31/03	$ 1,241,044
Matured 1/1/04	(20,860)
Refunded Bonds	(447,043)
Refunding Bonds	446,370
Bonds Outstanding 12/31/04	$ 1,219,511

DEBT OUTSTANDING AS OF 12/31/04

	Bonds Outstanding	Weighted Average Interest Cost
Fixed Rate Bonds*		
2004	$ 788,580	5.32%
2003	$ 950,215	5.48%
Variable Rate Bonds		
2004	$ 320,200	1.21%
2003	$ 278,800	0.99%
Capital Appreciation Bonds		
2004	$ 110,731	5.55%
2003	$ 12,029	7.53%
Total		
2004	$ 1,219,511	4.35%
2003	$ 1,241,044	4.56%

* Includes $60 million variable rate bonds synthetically swapped to fixed in 2004

For more information on annual financial statements and operating results, see the Management's Discussion and Analysis in the following Independent Auditors' Report.

Financial Highlights

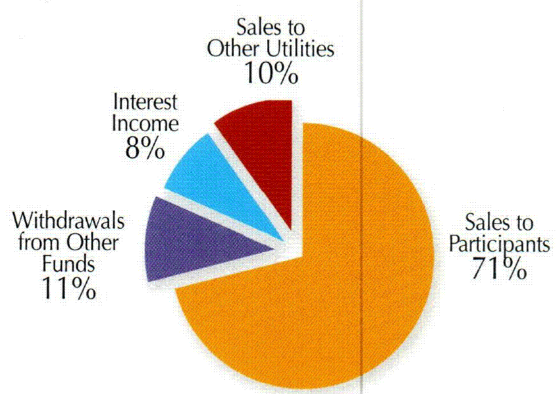
PMPA revenue comes from three primary sources: operating revenues; interest income; and withdrawals from other funds. Expenses are categorized by: debt service; operations and maintenance; purchased power; and other deposits and expenses.

SCHEDULE OF REVENUE AND EXPENSE PER THE BOND RESOLUTION AND OTHER AGREEMENTS

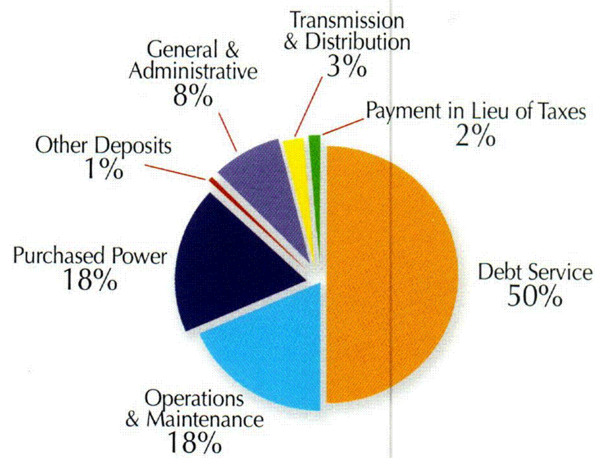
(Dollars in $000s)

REVENUE			
Sales to Participants	$	128,469	71%
Sales to Other Utilities		17,796	10%
Withdrawal from Other Funds		19,701	11%
Interest Income		14,582	8%
Total	$	180,548	100%
EXPENSE			
Debt Service	$	89,991	50%
Operations & Maintenance		32,170	18%
Purchased Power		32,331	18%
General & Administrative		14,648	8%
Transmission & Distribution		5,848	3%
Payment in Lieu of Taxes		4,400	2%
Other Deposits		1,160	1%
Total	$	180,548	100%

REVENUE



EXPENSE



C03

Responding

Empowering

Delivering

Independent Auditors' Report

Independent Auditors' Report

The Board of Directors
Piedmont Municipal Power Agency

We have audited the accompanying financial statements of Piedmont Municipal Power Agency (the Agency) as of and for the years ended December 31, 2004 and 2003, as listed in the table of contents. These financial statements are the responsibility of the Agency'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 consideration of internal control over financial reporting. As a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Agency's internal control over financial reporting. Accordingly, we express no such opinion. 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, the financial statements referred to above present fairly, in all material respects, the financial position of the Agency, as of December 31, 2004 and 2003, and the changes in its financial position and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in note 2(N) to the financial statements, the Agency adopted the provisions of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003.

The management's discussion and analysis on pages 23 through 27 is not a required part of the financial statements but is supplementary information required by accounting principles generally accepted in the United States of America. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

Our audits were conducted for the purpose of forming an opinion on the Agency's financial statements taken as a whole. The supplementary information included in schedules 1 and 2 is presented for purposes of additional analysis and is not a required part of the financial statements. The accompanying schedules have been prepared in accordance with the Bond Resolution. Such information has been subjected to the auditing procedures applied in the audits of the financial statements and, in our opinion, is fairly stated in all material respects in relation to the financial statements taken as a whole.

KPMG LLP

March 25, 2005

Management's Discussion & Analysis

Contents

Overview of the Financial Statements

This section of Piedmont Municipal Power Agency's (PMPA) annual financial statements presents our analysis of PMPA's financial performance during the fiscal year that ended December 31, 2004. Please read this discussion and analysis in conjunction with the financial statements which follow this section.

Financial Highlights

PMPA's total assets as of December 31, 2004 increased by $10.7 million over the prior year. This increase primarily consists of additions to noncurrent assets including net costs recoverable from future Participant billings offset by decreases in investments. A portion of the aforementioned increases were offset by a decrease in current assets where funds were used to meet 2004 operating expenses as well as to fund equity contributions relating to a restructuring of our outstanding debt portfolio completed in 2004.

Total liabilities at December 31, 2004 decreased by $6.4 million when compared with December 31, 2003. A portion of this decrease is the result of the 2004 debt restructuring where bond-related liabilities were reduced by $18.8 million when compared to the prior year. Miscellaneous current liabilities and reserves for decommissioning increased by $4.9 million and PMPA recognized a $7.5 million liability for derivative instruments at December 31, 2004.

As a direct result of the Nuclear Regulatory Commission's approval of the Catawba Nuclear Station's license extension from 2024 and 2026 for units one and two, respectively, to 2043 for both units, the Agency restructured a portion of its outstanding debt by extending the final maturity of its bonds an additional nine years to 2034. This debt extension, completed in August 2004, is expected to reduce debt service by an average annual amount of $15 million per year through January 1, 2025. In order to complete this restructuring, debt issuance expense was funded with $23 million in equity contributions and the net effect on bonds payable was a decrease of $673,000.

Overview of the Financial Statements

The following is an overview of the financial activities of PMPA for the years ended December 31, 2004 and 2003.

PMPA's financial statements, which include the statements of net assets, the statements of revenues, expenses and changes in net assets, and the statements of cash flows, are presented to display information about the reporting entity as a whole in accordance with GASB No. 34. The statements are prepared using the economic resources measurement focus and the accrual basis of accounting.

Management's Discussion & Analysis

FINANCIAL INFORMATION

The following summarizes the activities of PMPA for the years 2004 and 2003:

	2004	(In thousands)	2003
Revenues:			
Sales of electricity to Participants	$127,393		$ 123,479
Sales of electricity to other utilities and other operating revenues	18,872		17,249
Total operating revenues	146,265		140,728
Interest income	14,582		15,225
Other	4,232		4,222
Total revenues	165,079		160,175
Expenses:			
Operation, maintenance, and nuclear fuel amortization	29,452		29,067
Purchased power, transmission, and distribution	38,179		32,092
Administrative, general, and property taxes	19,048		17,399
Depreciation	6,834		18,969
Interest and amortization expense	70,726		73,422
Net decrease in fair value of investments and derivative instruments	16,826		8,165
Other	7,408		8,134
Total expenses	188,473		187,248
Net expenses recoverable from future Participant billings	40,545		40,009
Income before cumulative effect of a change in accounting principle	17,151		12,936
Cumulative effect of a change in accounting principle	—		4,068
Change in net assets	17,151		17,004
Net assets – beginning	65,184		48,180
Net assets – ending	$ 82,335		$ 65,184

RESULTS OF OPERATIONS

Revenues

Sales of Electricity to Participants. PMPA's primary source of revenue increased in 2004 by over 3% or approximately $3.9 million. A 2.08% rate increase implemented on May 1, 2004 coupled with a 5.8% increase in energy sales are the primary components of the revenue increase.

Surplus energy sales to third parties contributed to a 9% increase in sales of electricity to other utilities due to an 11% increase in available energy and improved market pricing. High competitive market pricing for oil and gas generation boosted the PMPA market rate charged for surplus energy from 25 mills in 2003 to 29 mills in 2004, a 16% increase in price.

Expenses

Purchased power expenses increased by 19%, or approximately $6.1 million, in 2004. PMPA purchases supplemental capacity and energy through an Interconnection Agreement with Duke Power. These purchases are tied to contractual formulas which are tied to generation of other Catawba owners. Due to the fact that certain Catawba owners have cancelled portions of their Interconnection Agreements with Duke Power, their generation strategies have changed as a result, thus causing PMPA's contractual formula rates charged by Duke to increase in 2004. PMPA has given notice to Duke of its intent to cancel PMPA's Interconnection Agreement with Duke on January 1, 2006, at which time we expect to begin purchasing supplemental power from Southern Company, and removing much uncertainty from purchased power pricing.

Depreciation of PMPA's ownership share of the Catawba Nuclear Station has declined as a result of the Nuclear Regulatory Commission's approval of the Catawba license extension. The remaining undepreciated plant value is depreciated over the remaining plant life, which is forty years.

PMPA entered into a floating to fixed rate step-coupon swap as part of the 2004 debt restructuring that helped to produce level debt service without issuing more capital appreciation debt and increased the benefits of the restructuring through January 1, 2025. Under this step-coupon swap, PMPA will pay a below market rate of interest for the first twenty years and an above market rate for the last ten years resulting in an approximate market rate over the entire term of the swap. This swap was designed to minimize the amount of Capital Appreciation bonds PMPA needed to issue as part of the 2004 restructuring. By paying an artificially low rate for the first twenty years, should the swap terminate during this period, it is likely that PMPA would owe a payment to the swap counterparty. This negative valuation comprises the majority of the increase in the net decrease in the fair value of investments for 2004.

In 2003 the cumulative effect of a change in accounting principle resulted from the Agency's adoption of SFAS No. 143 on January 1, 2003, regarding Accounting for Asset Retirements. Generally, this rule requires asset retirement obligations which are legally enforceable to be accrued as additional plant costs and amortized over the life of the related asset. In accordance with the transition provisions, the Agency recorded an obligation and corresponding asset of $22.9 million as of the date the liability was incurred. Concurrently, the Agency recorded accretion of the obligation and depreciation expense of $32.2 million and $6.8 million, respectively, for the period from the date the obligation was incurred through January 1, 2003. This resulted in a net cumulative-effect-type adjustment of $4.1 million in the statement of revenues, expenses, and changes in net assets for the year ended December 31, 2003.

Assets, liabilities, and net assets are summarized as follows:

	2004	2003
	(In thousands)	
Assets:		
Capital assets	$ 294,146	$ 292,982
Current unrestricted assets	188,569	246,166
Current restricted assets	188,246	198,983
Other noncurrent assets	725,797	647,891
Total assets	$ 1,396,758	$ 1,386,022
Liabilities:		
Long-term liabilities	$ 1,230,961	$ 1,238,232
Current liabilities	83,462	82,606
Total liabilities	1,314,423	1,320,838
Net assets:		
Invested in capital assets, net of related debt	(900,454)	(908,243)
Restricted for debt service	58,453	62,308
Restricted for other	14,924	15,087
Unrestricted	909,412	896,032
Total net assets	82,335	65,184
Total liabilities and net assets	$ 1,396,758	$ 1,386,022

Changes in PMPA's current unrestricted assets include decreases in the Rate Stabilization Account balance of approximately $20 million to fund operations, as well as $23 million to fund equity contributions to the 2004 bond restructuring. These $20 million funds were used as part of 2004 planned budget withdrawals to stabilize annual rate increases to the Participants, and the $23 million was used to implement a debt restructuring designed to show significant reduction in debt service in future years through 2024. The remaining decrease in unrestricted assets involve decreases in working capital funds used for operations, reductions in working capital funds required to be on hand by Duke Power and decreases in the market valuation of investments.

Restricted assets decreased primarily as a result of the resizing of the required balances of PMPA's debt service reserve accounts due to the 2004 debt restructuring.

Noncurrent assets increased as revenues collected from prior periods were recognized due to the use of Rate Stabilization Funds. Other noncurrent asset increases include increase in debt issuance costs and costs on advance refunding of debt related to the 2004 debt restructuring.

As bonds matured on January 1, 2004, long-term repayment obligations that were funded in the prior year were retired, resulting in a decrease in debt outstanding.

CAPITAL ASSETS

PMPA's capital assets include structures and improvements, reactor plant equipment, turbo generator units, other equipment and nuclear fuel. Such amounts are detailed as follows:

	2004	2003
	(In thousands)	
Structures and improvements	$ 157,609	$ 154,690
Reactor plant equipment	247,572	247,572
Turbo generator units	69,270	69,270
Other equipment	76,655	75,467
Nuclear fuel	33,901	36,611
Other	29,384	30,167
Construction in progress	9,873	7,578
Total	624,264	621,355
Less accumulated depreciation	(330,118)	(328,373)
Total, net	$ 294,146	$ 292,982

PMPA's capital assets include generation facilities, nuclear fuel, equipment and buildings as detailed above. PMPA's investment in capital assets at December 31, 2004 totaled $294.1 million (net of accumulated depreciation), a $1.2 million increase over 2003. Major capital transactions during the year included the following:

- Additions, net of retirements, to Catawba Plant of approximately $2.9 million.
- Transmission plant additions of $1.2 million.
- Decrease in nuclear fuel of $2.7 million ($7.6 million was added to fuel and $10.3 million of fully amortized fuel was written off).
- Construction work in process representing $2.3 million of capital additions at Catawba.
- Depreciation and amortization expense of $13.1 million.

Duke Energy Corporation, acting on behalf of the owners of the Catawba Nuclear Station (Station), in June 2001, filed an application for a 20-year extension of the license for Units 1 and 2 with the NRC. Following extensive reviews of this request, on December 5, 2003, the NRC approved the issuance of renewed operating licenses that will allow the Station to operate and produce electricity to 2043. Catawba's original licenses for each unit were scheduled to expire in 2024 and 2026, respectively. Due to this extension, the Catawba Nuclear Station will be depreciated on a straight line basis over the remaining expected and extended useful life of the Station, through December 2043.

DEBT MANAGEMENT

Following the favorable results on the relicensing application discussed above, PMPA, in August of 2004, undertook a major debt restructuring and extension of its debt portfolio to restructure a portion of its outstanding bonds to reduce debt service through January 1, 2025 by extending debt service over a portion of the extended license period.

PMPA offered two refunding issues, as follows. The first issue, Electric Revenue Bonds 2004A Refunding Series, aggregated $205,970,042 and consisted of $103,300,000 of federally taxable bonds and $102,670,042 of Capital Appreciation Bonds (CABs). The second issue, Electric Revenue Bonds, 2004B Refunding Series, totaled $240,400,000 and consisted of Variable Rate Demand Obligations (VRDOs). In conjunction with the VRDO issue, PMPA entered into a floating to fixed rate step coupon swap to convert some of its variable payment to a synthetic fixed rate. This step-coupon swap, which is designed to emulate a CAB structure at a lower cost while reducing the amount of CABs that had to be issued in the open market, is structured so that PMPA would pay an artificially low fixed rate of interest through January 1, 2025 and an artificially high rate of fixed rate interest from January 1, 2025 through January 1, 2034, while receiving a variable rate equal to the Bond Market Association Municipal Swap Index on a notional amount of $60 million.

The overall effect of these restructuring actions is to:

- Extend a portion of PMPA's debt service to January 1, 2034, nearing the full term of the Catawba Project Power Sales Agreements (which terminate August 1, 2035).
- Decrease annual costs during the existing debt service period (through 2024) by extending debt service over a portion of the extended license period. Expected average annual savings of $15 million are projected through 2024.
- Produce substantially level annual debt service.
- More closely match debt service to the useful life of the Catawba Project, thus effectively spreading the related revenue requirement ratably over the period expected to benefit from the use of the assets.

PMPA's total debt decreased $21.5 million during the year of which $20.9 million was paid January 1, 2004 in accordance with debt service schedules and $0.6 million was paid as part of a debt restructuring described above.

In July 2004 PMPA's bond ratings were raised by Standard and Poor's Corporation from BBB- to BBB with the outlook remaining at stable. Moody's Investors Service changed its outlook from positive to stable while maintaining its Baa3 rating and FitchRatings remained unchanged at BBB with a stable outlook.

ECONOMIC FACTORS & NEXT YEAR'S RATES

PMPA Participants have weathered the relocation of textile manufacturing facilities to overseas competition and have seen improvements in economic development in 2004. The fiscal year 2005 budget allows for a 1.8% growth in demand and energy and a 1.26% rate increase to Participants.

Increases in market rates for generating fuel have had a positive effect on PMPA as we collect more for surplus energy sales and are somewhat isolated from the swings in oil and gas fuel prices as we are dependent on nuclear fuel sources.

REQUEST FOR INFORMATION

This financial report is provided as an overview of PMPA's finances. Questions concerning any of the information in this report or requests for additional information should be directed to the office of Suzanne Armendariz, Director of Finance, Piedmont Municipal Power Agency, 121 Village Drive, Greer, South Carolina 29651.

Statements of Net Assets

DECEMBER 31, 2004 AND 2003

(DOLLARS IN $000s)

ASSETS	2004	2003
Capital assets (note 5):		
Utility plant assets being depreciated	$ 614,055	$ 613,441
Accumulated depreciation and amortization	(330,118)	(328,373)
Total utility plant assets being depreciated, net	283,937	285,068
Utility plant assets not being depreciated	10,209	7,914
Total capital assets, net	294,146	292,982
Current assets (note 7):		
Cash	11,293	12,353
Marketable debt securities	155,502	208,381
Accrued interest receivable	1,132	2,742
Participant accounts receivable	9,475	10,069
Other accounts receivable	5,446	3,573
Materials and supplies	5,721	6,110
Derivative financial instruments (note 15)	—	2,938
Total current unrestricted assets	188,569	246,166
Restricted assets (note 6):		
Restricted for debt service	123,694	136,226
Restricted for decommissioning	49,628	47,670
Restricted for other	14,924	15,087
Total current restricted assets	188,246	198,983
Total current assets	376,815	445,149
Noncurrent assets:		
Unamortized debt issuance costs	35,989	16,305
Net costs recoverable from future Participant billings (note 8)	525,138	484,593
Costs on advance refunding of debt, net	162,632	144,790
Other	2,038	2,203
Total other assets	725,797	647,891
Total assets	$ 1,396,758	$ 1,386,022

LIABILITIES AND NET ASSETS	2004	2003
Long-term liabilities (notes 9 and 10):		
Bonds payable, net	$ 1,170,200	$ 1,180,365
Reserve for decommissioning (note 11)	60,761	57,867
Total long-term liabilities	1,230,961	1,238,232
Current liabilities:		
Accounts payable and accrued liabilities	10,707	8,688
Derivative financial instruments (notes 7 and 15)	7,514	—
	18,221	8,688
Current liabilities payable from restricted assets:		
Accrued interest payable	40,841	53,058
Current installments of bonds payable	24,400	20,860
Total current liabilities payable from restricted assets	65,241	73,918
Total current liabilities	83,462	82,606
Total liabilities	1,314,423	1,320,838
Net assets:		
Investment in capital assets, net of related debt	(900,454)	(908,243)
Restricted for debt service	58,453	62,308
Restricted for other	14,924	15,087
Unrestricted	909,412	896,032
Total net assets	82,335	65,184
Total liabilities and net assets	$ 1,396,758	$ 1,386,022

See accompanying notes to financial statements.

Statements of Revenues, Expenses, and Changes in Net Assets

YEARS ENDED DECEMBER 31, 2004 AND 2003

(DOLLARS IN $000s)

	2004	2003
Operating revenues:		
Sales of electricity to Participants	$ 127,393	$ 123,479
Sales of electricity to other utilities	17,796	16,173
Other	1,076	1,076
Total operating revenues	146,265	140,728
Operating expenses:		
Operation and maintenance	23,158	22,800
Nuclear fuel amortization	6,294	6,267
Purchased power (note 4)	32,331	26,023
Transmission	4,652	4,678
Distribution	1,196	1,391
Administrative and general	14,648	13,164
Depreciation (note 5)	6,834	18,969
Decommissioning	2,894	2,756
Payments in lieu of property taxes	4,400	4,235
Total operating expenses	96,407	100,283
Operating income	49,858	40,445
Nonoperating revenues (expenses):		
Interest income	14,582	15,225
Net decrease in fair value of investments and derivative instruments	(16,826)	(8,165)
Interest expense	(58,859)	(61,070)
Amortization expense	(11,867)	(12,352)
Other expense, net	(282)	(1,156)
Total nonoperating expenses, net	(73,252)	(67,518)
Loss before deferred items and cumulative effect of a change in accounting principle	(23,394)	(27,073)
Net expenses recoverable from future Participant billings (note 8)	40,545	40,009
Income before cumulative effect of a change in accounting principle	17,151	12,936
Cumulative effect of a change in accounting principle (note 2(N))	—	4,068
Change in net assets	17,151	17,004
Net assets at beginning of year	65,184	48,180
Net assets at end of year	$ 82,335	$ 65,184

See accompanying notes to financial statements.

Statements of Cash Flows

YEARS ENDED DECEMBER 31, 2004 AND 2003

(DOLLARS IN $000s)

	2004	2003
Cash flows from operating activities:		
Receipts from customers	$ 127,318	$ 123,698
Payments for operations and maintenance	(23,158)	(22,800)
Payments for purchased power, transmission and distribution	(19,289)	(14,159)
Payments for administrative and general	(18,024)	(17,542)
Net cash provided by operating activities	66,847	69,197
Cash flows from investing activities:		
Purchase of investment securities	(487,758)	(334,524)
Proceeds from sales and maturities of investment securities	545,748	348,416
Interest received on investments	15,167	15,480
Interest received on Duke working capital	277	491
Interest received on derivative instruments	4,143	4,189
Net cash provided by investing activities	77,577	34,052
Cash flows from capital and related financing activities:		
Proceeds from issuance of bonds	446,308	—
Refunding of bonds	(469,830)	—
Payments of bond principal	(20,860)	(21,965)
Interest payments on bonds	(56,553)	(55,782)
Debt issuance costs	(25,855)	—
Payments for arbitrage liability	(137)	—
Expenditures for electric plant in service	(6,686)	(4,362)
Expenditures for nuclear fuel	(7,606)	(10,421)
Payments to Duke for other charges	(3,233)	(4,899)
Other	(1,032)	(869)
Net cash used in capital and related financing activities	(145,484)	(98,298)
Net increase (decrease) in cash	(1,060)	4,951
Cash at beginning of year	12,353	7,402
Cash at end of year	$ 11,293	$ 12,353
Reconciliation of operating income to net cash provided by operating activities:		
Operating income	$ 49,858	$ 40,445
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation and fuel amortization	13,128	25,236
Reserve for decommissioning	2,894	2,756
Decrease (increase) in:		
Participant accounts receivable	594	(339)
Other accounts receivable	(1,536)	669
Materials and supplies	389	(137)
Increase in:		
Accounts payable and accrued liabilities	1,520	567
Net cash provided by operating activities	$ 66,847	$ 69,197
Noncash investing, capital, and financing activities:		
Net decrease in fair value of investments and derivative instruments	$ (16,826)	$ (8,165)
Recording of reserve for decommissioning and corresponding asset upon adoption of SFAS No. 143	$ —	$ 22,900

See accompanying notes to financial statements.

1. DESCRIPTION OF THE ENTITY, INDUSTRY RESTRUCTURING DEVELOPMENTS, AND RELATED UNCERTAINTIES

A. *Description of the Entity*

Piedmont Municipal Power Agency (Agency) was incorporated in 1979 under the South Carolina Joint Municipal Electric Power and Energy Act. The Act, adopted April 1978, enabled the formation, by South Carolina municipalities and municipal commissions of public works, of a joint agency to plan, finance, develop, own, and operate electric generation and transmission facilities. Ten municipal utility systems (Participants) comprise the Agency's membership. The Participants, located in northwestern South Carolina, are the cities of Abbeville, Clinton, Easley, Gaffney, Greer, Laurens, Newberry, Rock Hill, Union, and Westminster.

The Agency and Duke Power Company (Duke) are parties to agreements giving the Agency a 25% undivided ownership interest in Catawba Nuclear Station Unit 2 (Project). Duke is the operating owner of the Project. The Agency's Project power output entitlements (approximately 286 MW) come from Catawba Nuclear Station Units 1 and 2; subject to the terms of the Interconnection Agreement containing the "Catawba Reliability Exchange" provision under which the Agency pays 12.5% of the costs and receives 12.5% of the power output associated with each of these 1,145 MW units. Additionally, the terms of the Interconnection Agreement containing the "McGuire Reliability Exchange" provision which allows transfers of energy between the Agency's resulting entitlements from the Catawba Units and Duke's two nuclear units at McGuire Nuclear Station. The operating licenses for Catawba Unit 1 and Unit 2 expire on December 5, 2043.

B. *Industry Restructuring Developments and Related Uncertainties*

The Agency has developed a strategic plan to help guide it through the potential industry changes. The plan includes periodic reviews of the recoverability of regulatory assets and the impact of such recovery on the Agency's rates. The Agency's management is participating in the deregulation debate, both on the national and state level.

In the event that the electric utility industry is restructured, the Agency and the Participants can expect to have as their major competition the investor-owned utilities and rural electric cooperatives presently operating in South Carolina and independent power producers, power marketers and others that may offer retail and wholesale services in South Carolina after restructuring. The Participants' present retail electric rates are higher, on average, than the present retail electric rates of the area's investor-owned utilities.

The Agency's present charges to the Participants, together with planned withdrawals from the Rate Stabilization Account, are sufficient to recover all of the Agency's current costs of supplying the Participants' bulk power supply. Currently each Participant is able, and under its Power Sales Agreements is required, to set its rates at levels necessary to pay all the costs of its electric utility system, including the Agency's charges for supplying power to the Participants. However, studies by the Agency indicate that, in a deregulated electric utility industry, anticipated market-based retail rates would be lower than those that the Participants would need to charge to pay the Agency's costs and the expenses of their electric utility systems. These circumstances could give rise to stranded investments of the Agency and the Participants and the need for stranded investment recovery by the Agency and the Participants.

For the Agency and the Participants to be competitive in a deregulated retail electric utility industry, the Agency and the Participants must recover the Agency's substantial stranded investments in the Project. The Agency expects the methods by which it and the Participants may recover some or all of these stranded investments would come from legislative initiatives. As a result of the foregoing described uncertainties, including the inability to predict the outcome of the legislative process, no assurance can be given that the Agency and the Participants would be able to recover, in whole or in part, these stranded investments in the event of deregulation of the retail electric utility industry.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. *Basis of Accounting*

The financial statements have been prepared in accordance with the provisions of GASB Statement No. 34, *Basic Financial Statements – and Management's Discussion and Analysis – for State and Local Governments* as amended by GASB Statement No. 37, *Basic Financial Statements – and Management's Discussion and Analysis – for State and Local Governments: Omnibus* and GASB Statement No. 38, *Certain Financial Statement Disclosures*. Statement No. 34 requires as supplementary information Management's Discussion and Analysis, which includes an analytical overview of the Agency's financial activities.

The Agency's accounting records are maintained on an accrual basis in conformity with accounting principles generally accepted in the United States of America and substantially in conformity with the Federal Energy Regulatory Commission's Uniform System of Accounts.

The Agency follows the accounting practices set forth in Statement of Financial Accounting Standards No. 71 (SFAS No. 71), *Accounting for the Effects of Certain Types of Regulation*, as amended. This standard allows the Agency to capitalize or defer certain costs or revenues based on the Agency's ongoing assessment that it is probable that such items will be recovered through future revenues based on the rate-making authority of the Agency's board of directors (Board). The criteria require consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized cost.

The Agency's General Bond Resolution requires that its rate structure be designed to produce revenues sufficient to pay operating, debt service, and other specified costs. The Agency's Board, which is comprised of representatives of the Participants, is responsible for reviewing and approving the rate structure. The application of a given rate structure to a given period's electricity sales may produce revenues not intended to pay that period's costs, and conversely, that period's costs may not be intended to be recovered in period revenues. The affected revenues and/or costs are, in such cases, deferred for future recognition. The ultimate recognition of deferred items is correlated with specific future events, primarily payment of debt principal.

Under Governmental Accounting Standards Board (GASB) Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting,* the Agency has adopted the option to apply Financial Accounting Standards Board (FASB) statements and interpretations that do not conflict with or contradict GASB pronouncements.

B. *Unamortized Debt Issuance Costs*

Unamortized debt issuance costs at December 31, 2004 and 2003 of $35,989 and $16,305, respectively, (net of accumulated amortization of $9,012 and $18,225, respectively) are being amortized over the term of the related debt.

C. *Costs on Advance Refundings of Debt*

Costs on advance refundings of debt at December 31, 2004 and 2003 of $162,632 and $144,790, respectively, (net of accumulated amortization of $171,492 and $159,914, respectively) have been deferred in accordance with SFAS No. 71 and are being amortized over the term of the debt issued on refunding.

D. *Discounts on Bonds Payable*

The discounts on bonds payable at December 31, 2004 and 2003 of $25,476 and $40,620, respectively, (net of accumulated amortization of $18,505 and $37,631 respectively) are being amortized on the bonds outstanding method, which approximates the effective interest method.

E. *Premiums on Bonds Payable*

The premiums on bonds payable at December 31, 2004 and 2003 of $565 and $801, respectively, (net of accumulated amortization of $838 and $2,333, respectively) are being amortized on the bonds outstanding method, which approximates the effective interest method.

F. *Income Taxes*

The Agency is recognized as a public utility for federal income tax purposes. As such, gross income of the Agency is excluded from federal income taxes under Internal Revenue Code Section 115.

G. *Cash Flows*

For purposes of the statements of cash flows, the Agency considers deposits with banks and Duke to be cash.

H. *Marketable Debt Securities*

As authorized by the General Bond Resolution, investment securities at December 31, 2004 and 2003 consist only of direct obligations of the United States government and obligations of United States government agencies. These investments are uninsured and unregistered and are held by the Agency's trustee in the Agency's name.

Marketable debt securities are recorded at fair value. Unrealized holding gains and losses on marketable debt securities are included in income. Interest income is recognized when earned.

I. *Capital Assets*

Electric plant in service, including unclassified assets, is stated at cost and is depreciated on a straight-line basis at rates calculated to depreciate the composite assets over their respective estimated useful lives. Depreciation begins when assets are placed into service. The Agency's annual provision for depreciation expressed as a percentage of the average balance of depreciable utility plant was 1.1% for 2004 and 3.3% for 2003.

J. *Materials and Supplies*

Materials and supplies inventories are stated at lower of cost or market using the average cost method.

K. *Use of Estimates*

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

L. *Net Assets*

Net assets are categorized as invested in capital assets, net of related debt, restricted and unrestricted.

Net assets invested in capital assets, net of related debt, is intended to reflect the portion of net assets which are associated with nonliquid, capital assets less outstanding capital asset related debt.

(DOLLARS IN $000s)

Restricted net assets are assets that have third-party (statutory or bond covenant) limitations on their use. When both restricted and unrestricted resources are available, restricted resources will be used first for incurred expenses, and then unrestricted as needed.

Unrestricted assets consist of all other net assets not included in the previous categories.

M. *Revenue Recognition*

The Agency recognizes revenue on sales when the electricity is delivered to the customers. Accounts receivable are recorded at the invoiced amount and do not bear interest. The Agency has not recorded an allowance for doubtful accounts as it historically had not had any collection problems or write-offs.

N. *Recently Adopted Accounting Standards*

On January 1, 2003, the Agency adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires an entity to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets.

In accordance with the transition provisions of SFAS No. 143, on January 1, 2003, the Agency recorded an obligation and corresponding asset of $22,900 as of the date the liability was incurred. Concurrently, the Agency recorded accretion of the obligation and depreciation expense of $32,211 and $6,793, respectively, for the period from the date the obligation was incurred through January 1, 2003, and removed its existing reserve for decommissioning of $43,072 as of January 1, 2003. This resulted in a net cumulative-effect-type adjustment of $4,068 in the statement of revenues, expenses, and changes in net assets for the year ended December 31, 2003.

O. *Derivative Financial Instruments*

All derivatives are recognized on the statements of net assets at their fair value. The Agency has not designated any of its derivatives as hedges. Changes in the fair value of derivative instruments are reported in current-period revenues and expenses.

3. POWER SALES AGREEMENTS

A. *Catawba Project Power Sales Agreements*

The Agency and each Participant are parties to Catawba Project Power Sales Agreements (Sales Agreements). These Sales Agreements oblige the Agency to provide each Participant a share of Project power output and, in turn, each Participant must pay its share of Project costs. Participants make their payments on a "take-or-pay" basis whether or not the Project is operable or operating. Such payments are not subject to reduction or offset and are not conditioned upon performance by the Agency or any given Participant. The Sales Agreements are in effect until the earlier of August 1, 2035, or the completion of payments on the bonds and satisfaction of obligations under the Project agreements.

The Participants' Shares of the Agency's Catawba Project Output are as follows:

City of Abbeville	2.68%
City of Clinton	7.84%
City of Easley	13.24%
City of Gaffney	10.05%
City of Greer	9.34%
City of Laurens	6.49%
City of Newberry	10.47%
City of Rock Hill	28.04%
City of Union	10.01%
City of Westminster	1.84%
	100.00%

B. *Supplemental Power Sales Agreements*

The Agency and each Participant are also parties to Supplemental Power Sales Agreements (Supplemental Agreements) under which each Participant has agreed to pay, in exchange for supplemental bulk power supply, its share of supplemental bulk power supply costs. A Participant may terminate its Supplemental Agreement with ten years advance notice.

4. PROJECT AGREEMENTS

Project Agreements between the Agency and Duke consist of the Catawba Nuclear Station Purchase, Construction and Ownership Agreement (the Purchase Agreement), the Catawba Nuclear Station Operating and Fuel Agreement (the Operating Agreement), and the Catawba Nuclear Station Interconnection Agreement (the Interconnection Agreement).

A. *Purchase Agreement*

This agreement between the Agency and Duke provides for the purchase of the Catawba Project by the Agency. It also details Duke's responsibilities, as engineer-contractor, for construction, initial fueling, and placing the Catawba Nuclear Station into commercial operation.

B. *Operating Agreement*

This agreement, between the Agency and Duke, provides for Duke, as operator for the Agency, to be responsible for the operation, maintenance, and fueling of Catawba and for making of renewals, replacements, and capital additions. In addition, the Operating Agreement provides for decommissioning of Catawba at the end of its useful life pursuant to the terms of a decommissioning agreement, separate from the Operating Agreement.

(DOLLARS IN $000s)

C. *Interconnection Agreement*

This agreement, between the Agency and Duke, provides for interconnection of the Agency's ownership share of Catawba Unit 1 with the Duke system. As part of the Interconnection Agreement, the Agency is allowed to exchange capacity and output of four nuclear units. The agreement also provides for sale by the Agency of surplus energy to Duke and third parties. It also makes provision for the purchase of supplemental capacity and energy, transmission services, and reserve purchases. Amounts due from Duke for surplus energy and exchange capacity sales are netted against amounts payable to Duke for the operation of the Catawba plant.

The agency has notified Duke of its intent to cancel the Interconnection Agreement effective January 1, 2006, and has contracted with Southern Power Company and Southern Company Services, Inc. to purchase supplemental capacity and energy and reserve purchases until December 31, 2010.

5. CAPITAL ASSETS

The following is a summary of capital asset activity for the years ended December 31, 2004 and 2003:

	December 31, 2004			
Utility plant being depreciated:	Beginning balance	Increase	Decrease	Ending balance
Structures and improvements	$ 154,690	$ 3,745	$ (826)	$ 157,609
Reactor plant equipment	247,572	—	—	247,572
Turbo generator units	69,270	—	—	69,270
Accessory electric equipment	50,586	—	—	50,586
Miscellaneous plant equipment	18,131	—	—	18,131
Station equipment	5,508	21	—	5,529
Transmission equipment	1,242	1,167	—	2,409
Other	24,846	48	(6)	24,888
Unclassified	4,985	—	(825)	4,160
Nuclear fuel	36,611	7,606	(10,316)	33,901
Total utility plant assets being depreciated	613,441	12,587	(11,973)	614,055
Less accumulated depreciation and amortization	(328,373)	(13,128)	11,383	(330,118)
Total utility plant assets being depreciated, net	285,068	(541)	(590)	283,937
Utility plant assets not being depreciated:				
Land	336	—	—	336
Construction work-in-progress	7,578	6,639	(4,344)	9,873
Total utility plant assets not being depreciated	7,914	6,639	(4,344)	10,209
Total capital assets, net	$ 292,982	$ 6,098	$ (4,934)	$ 294,146

	December 31, 2003			
Utility plant being depreciated:	Beginning balance	Increase	Decrease	Ending balance
Structures and improvements	$ 155,689	$ 7	$ (1,006)	$ 154,690
Reactor plant equipment	247,777	—	(205)	247,572
Turbo generator units	69,270	—	—	69,270
Accessory electric equipment	50,602	—	(16)	50,586
Miscellaneous plant equipment	16,749	1,386	(4)	18,131
Station equipment	5,508	—	—	5,508
Transmission equipment	1,242	—	—	1,242
Other	1,925	22,974	(53)	24,846
Unclassified	4,910	75	—	4,985
Nuclear fuel	31,870	10,421	(5,680)	36,611
Total utility plant assets being depreciated	585,542	34,863	(6,964)	613,441
Less accumulated depreciation and amortization	(303,385)	(32,029)	7,041	(328,373)
Total utility plant assets being depreciated, net	282,157	2,834	77	285,068
Utility plant assets not being depreciated:				
Land	336	—	—	336
Construction work-in-progress	4,835	4,351	(1,608)	7,578
Total utility plant assets not being depreciated	5,171	4,351	(1,608)	7,914
Total capital assets, net	$ 287,328	$ 7,185	$ (1,531)	$ 292,982

(DOLLARS IN $000s)

Unclassified assets are in service but not yet classified to specific plant accounts.

Nuclear fuel represents costs associated with acquiring and processing reload fuel assemblies as well as the cost of nuclear fuel in the reactor. Nuclear fuel is amortized based on burn rates using a unit of production basis. The Agency regularly writes off fully amortized nuclear fuel costs when fuel batches are replaced during core refueling operations. Fully amortized fuel costs of $10,316 and $5,680 were written off during 2004 and 2003, respectively.

A summary of accumulated depreciation and amortization at December 31, 2004 and 2003 are as follows:

	2004	2003
Accumulated depreciation of electric plant in service	$ 313,178	$ 307,412
Accumulated amortization of nuclear fuel	16,940	20,961
	$ 330,118	$ 328,373

The depreciation charge for 2004 on the Agency's generation plant has been determined based on revised estimated useful lives for these assets. The estimated useful lives were revised to recognize a 19-year extension of the operating license for Catawba Unit 1 and a 17-year extension of the operating license for Catawba Unit 2 through 2043 which Duke received in December 2003. The effect of the change in 2004 was to decrease depreciation expense by approximately $11,800 with a corresponding decrease in depreciation expense deferred to be recovered in future participant billings.

6. RESTRICTED ASSETS

The General Bond Resolution and Project agreements restrict the use of bond proceeds, Agency revenues, and Agency funds on hand. Certain restrictions define the order in which available funds may be used to pay costs; other restrictions require minimum balances or accumulation of balances for specific purposes. At December 31, 2004 and 2003, management believes the Agency was in compliance with all such restrictions and held the following restricted assets:

	2004		2003	
	Fair value	Amortized cost	Fair value	Amortized cost
Debt service – bond principal	$ 24,400	$ 24,400	$ 20,860	$ 20,860
Debt service – bond fixed rate interest	18,568	18,568	27,317	27,317
Debt service reserve	73,394	73,249	80,044	78,974
Reserve and contingency	7,332	7,325	8,005	7,897
Decommissioning	49,628	49,257	47,670	46,539
Special reserve	14,924	15,000	15,087	15,000
	$ 188,246	$ 187,799	$ 198,983	$ 196,587
Funds are comprised of:				
Marketable debt securities	$ 186,153	$ 185,706	$ 197,638	$ 195,242
Accrued interest receivable	2,093	2,093	1,345	1,345
	$ 188,246	$ 187,799	$ 198,983	$ 196,587

7. CURRENT UNRESTRICTED ASSETS AND CURRENT LIABILITIES

Current unrestricted assets and current liabilities are used in the Agency's day-to-day operations. The assets are allocated for the following purposes:

	2004		2003	
	Fair value	Amortized cost	Fair value	Amortized cost
Working capital	$ 88,949	$ 88,908	$ 94,495	$ 93,360
Derivative financial instruments asset (liability)	(7,514)	—	2,938	—
Fuel acquisition	27,249	27,249	28,561	28,561
Bond retirement fund	186	186	1,869	1,874
Rate stabilization	72,185	70,898	118,303	113,680
	$ 181,055	$ 187,241	$ 246,166	$ 237,475

Current unrestricted assets include $11,293 and $12,353 of uninsured and uncollateralized cash at December 31, 2004 and 2003, respectively. Accounts payable and accrued liabilities of $10,707 and $8,688 at December 31, 2004 and 2003, respectively, will be paid from working capital assets.

(DOLLARS IN $000s)

8. NET EXPENSES RECOVERABLE FROM FUTURE PARTICIPANT BILLINGS

As described in notes 1 and 2, rates charged to Participants are structured to systematically provide for debt requirements and operating costs of the Agency. The expenses and revenues excluded from rates are deferred to such periods as they are intended to be included in rates.

Net expenses recoverable from future Participant billings:

	2004	2003	Change
	(Cumulative totals)		
Items to be recovered in future Participant billings:			
Interest expense	$ 339,936	$ 336,172	$ 3,764
Depreciation expense	323,186	317,585	5,601
Amortization of redemption and defeasance losses	172,961	161,246	11,715
Amortization of bond discounts and premiums and debt issuance costs	73,755	70,586	3,169
Nuclear fuel expenses	873	873	—
Letter of credit fees	5,649	5,649	—
Other	2,392	2,392	—
	918,752	894,503	24,249
Items reducing future Participant billings:			
Investment income	(76,528)	(76,528)	—
Decrease (increase) in fair value of investments and derivative instruments	5,739	(11,087)	16,826
Rate stabilization (revenue received to reduce future billings to Participants)	(533,913)	(528,593)	(5,320)
Reserve and contingency deposits	(50,076)	(44,275)	(5,801)
	(654,778)	(660,483)	5,705
Revenues (expenses) recognized:			
Interest, depreciation, amortization expense included in Participant billings for debt principal payments	(210,153)	(171,869)	(38,284)
Rate stabilization draws applied to expenses	463,015	414,913	48,102
Reserve and contingency revenue applied to expenses	8,302	7,529	773
Net costs recoverable from future Participant billings	$ 525,138	$ 484,593	$ 40,545

The following expenses will be recognized in future periods when rates charged to Participants produce revenues sufficient to retire the debt that funded those costs:

- Interest expense on the Agency's bonds and variable rate demand obligations along with associated letter-of-credit, banking and re-marketing fees (except interest and fees related to Capital Appreciation Bonds) paid from bond proceeds during a defined "Construction Period," (net of income earned on the temporary investment of those bond proceeds);
- Interest expense on Capital Appreciation Bonds accrued but not paid until maturity;
- Amortization of debt issuance expenses, bond discounts and premiums, defeasance losses, redemption losses, and organization costs paid from or included in bond proceeds;
- Depreciation on utility plant constructed with bond proceeds and amortization of nuclear fuel acquired with bond proceeds; and
- Certain other project costs paid from bond proceeds.

The Agency has also deferred Participant revenues that, during the Construction Period, were established at levels to cover Project costs not paid from bond proceeds, as well as scheduled deposits to a Rate Stabilization account. The revenue associated with those scheduled deposits and the interest income thereon will be recognized when those funds are drawn upon to pay Project costs. Also, certain settlement revenues and excess revenues in certain funds have been transferred to the Rate Stabilization account and have been deferred for recognition until the time the funds are applied to the payment of Project costs.

Revenues or costs associated with increases or decreases in the fair value of investments have been deferred until such time the securities have matured or are sold.

Additionally, the Agency's General Bond Resolution requires Participant revenues to be established at levels sufficient to provide specified deposits into a Reserve and Contingency fund. Monies in that fund are used for the construction or acquisition of utility plant. The recognition of such revenues is deferred until such time as the depreciation is recorded on the assets constructed or acquired with those monies.

(DOLLARS IN $000s)

9. LONG-TERM LIABILITIES

Long term liabilities at December 31, 2004 and 2003 consist of the following:

	2003	Additions	Reductions	2004	Due within one year
1986 Refunding Series Electric Revenue Bonds, payable in 2025 with interest at 5%	$ 33,620	—	$ (11,745)	$ 21,875	—
1986A Refunding Series Electric Revenue Bonds, refunded in 2004	103,815	—	(103,815)	—	—
1988 Capital Appreciation Electric Revenue Bonds, payable annually and from 2010 to 2013 with interest at 7.75%	7,745	—	(2,934)	4,811	—
1988A Capital Appreciation Electric Revenue Bonds, payable annually from 2006 to 2015 with interest ranging from 7.5% to 7.65%	4,284	—	(1,034)	3,250	—
1991 Refunding Series Electric Revenue Bonds, payable annually from 2019 to 2023 with interest ranging from 4% to 6.75%	133,110	—	(21,620)	111,490	—
1991A Refunding Series Electric Revenue Bonds, payable in 2007 and from 2013 to 2018 with interest ranging from 5% to 6.5%	100,175	—	(39,940)	60,235	—
1992 Refunding Series Electric Revenue Bonds, refunded in 2004	19,940	—	(19,940)	—	—
1993 Refunding Series Electric Revenue Bonds, payable annually from 2007 to 2025 with interest ranging from 5.375% to 5.6%	72,175	—	(8,700)	63,475	—
1996A Refunding Series Electric Revenue Bonds, refunded in 2004	67,645	—	(67,645)	—	—
1996B Refunding Series Electric Revenue Bonds, payable annually from 2007 to 2013 with interest ranging from 5.25% to 6.0%	113,185	—	(15,305)	97,880	—
1996C Refunding Series Electric Revenue Bonds, refunded in 2004	50,000	—	(50,000)	—	—
1996D Refunding Series Electric Revenue Bonds, payable in 2025 with variable interest rates (1.21% and 1.01% at December 31, 2004 and 2003, respectively)	50,000	—	(39,000)	11,000	—
1997A Refunding Series Electric Revenue Bonds, payable in 2024 with variable interest rates (1.17% and 1.0% at December 31, 2004 and 2003, respectively)	31,700	—	—	31,700	—
1997B Refunding Series Electric Revenue Bonds, payable in 2016 to 2019 with variable interest rates (1.17% and 1.0% at December 31, 2004 and 2003, respectively)	63,000	—	—	63,000	—

(DOLLARS IN $000s)

	2003	Additions	Reductions	2004	Due within one year
1997C Refunding Series Electric Revenue Bonds, payable annually from 2016 to 2019 with variable interest rates (1.21% and 1.01% at December 31, 2004 and 2003, respectively)	34,100	—	—	34,100	—
1998A Refunding Series Electric Revenue Bonds, payable annually from 2006 to 2025 with interest ranging from 4.4% to 5.5%	161,380	—	—	161,380	—
1999A Refunding Series Electric Revenue Bonds, payable annually from 2014 to 2016 and 2020 to 2021 with interest at 5.25%	97,510	—	—	97,510	—
2002A Refunding Series Electric Revenue Bonds, payable annually from 2007 to 2008 and 2010 with interest ranging from 3.9% to 4.5%	47,660	—	(36,225)	11,435	—
2002B Refunding Series Electric Revenue Bonds, refunded in 2004	50,000	—	(50,000)	—	—
2004A Refunding Series Electric Revenue Bonds, Payable annually from 2005 to 2006 and 2010 to 2014 with interest ranging from 2.65% to 5.20%	—	103,300	—	103,300	24,400
2004B Refunding Series Electric Revenue Bonds, payable anually from 2031 to 2032 and 2034 with variable interest rates (1.46% at December 31, 2004)	—	240,400	—	240,400	—
2004A Capital Appreciation Electric Revenue Bonds, payable annually from 2022 to 2024, 2026 to 2032 and 2034	—	102,670	—	102,670	—
Total bonds payable	1,241,044	446,370	(467,903)	1,219,511	24,400
Less unamortized discount	(40,620)	(62)	15,206	(25,476)	
Plus unamortized premium	801	—	(236)	565	
Bonds payable, net	$ 1,201,225	$ 446,308	$ (452,933)	$ 1,194,600	$ 24,400

	2002	Additions	Reductions	2003	Due within one year
1986 Refunding Series Electric Revenue Bonds, payable in 2025 with interest at 5%	$ 33,620	—	—	$ 33,620	—
1986A Refunding Series Electric Revenue Bonds, payable in 2023 and 2024 with interest at 5.75%	103,815	—	—	103,815	—
1988 Capital Appreciation Electric Revenue Bonds, payable annually and from 2010 to 2013 with interest at 7.75%	7,745	—	—	7,745	—
1988A Capital Appreciation Electric Revenue Bonds, payable annually from 2004 to 2015 with interest ranging from 7.3% to 7.65%	4,284	—	—	4,284	540
1991 Refunding Series Electric Revenue Bonds, payable annually from 2005 to 2023 with interest ranging from 4% to 6.85%	133,110	—	—	133,110	—
1991A Refunding Series Electric Revenue Bonds, payable annually from 2002 to 2007 and from 2013 to 2018 with interest ranging from 5% to 6.5%	112,385	—	(12,210)	100,175	—
1992 Refunding Series Electric Revenue Bonds, payable annually from 2010 to 2014 with interest at 6.3%	19,940	—	—	19,940	—
1993 Refunding Series Electric Revenue Bonds, payable annually from 2002 to 2025 with interest ranging from 4.9% to 5.6%	74,840	—	(2,665)	72,175	515
1996A Refunding Series Electric Revenue Bonds, payable annually from 2013 to 2021 with interest ranging from 6.55% to 6.6%	69,140	—	(1,495)	67,645	—

(DOLLARS IN $000s)

	2002	Additions	Reductions	2003	Due within one year
1996B Refunding Series Electric Revenue Bonds, payable annually from 2002 to 2013 with interest ranging from 4.8% to 6.0%	117,580	—	(4,395)	113,185	3,375
1996C Refunding Series Electric Revenue Bonds, payable annually in 2021 to 2022 with variable interest rates (0.98% and 1.55% at December 31, 2003 and 2002, respectively)	50,000	—	—	50,000	—
1996D Refunding Series Electric Revenue Bonds, payable annually from 2022 to 2025 with variable interest rates (1.01% and 1.5% at December 31, 2003 and 2002, respectively)	50,000	—	—	50,000	—
1997A Refunding Series Electric Revenue Bonds, payable in 2024 with variable interest rates (1.0% and 1.6% at December 31, 2003 and 2002, respectively)	31,700	—	—	31,700	—
1997B Refunding Series Electric Revenue Bonds, payable annually from 2002 to 2003 and 2016 to 2019 with variable interest rates (1.0% and 1.55% at December 31, 2003 and 2002, respectively)	63,770	—	(770)	63,000	—
1997C Refunding Series Electric Revenue Bonds, payable annually from 2002 to 2003 and 2016 to 2019 with variable interest rates (1.01% and 1.6% at December 31, 2003 and 2002, respectively)	34,530	—	(430)	34,100	—
1998A Refunding Series Electric Revenue Bonds, payable annually from 2006 to 2025 with interest ranging from 4.4% to 5.5%	161,380	—	—	161,380	—
1999A Refunding Series Electric Revenue Bonds, payable annually from 2014 to 2016 and 2020 to 2021 with interest at 5.25%	97,510	—	—	97,510	—
2002A Refunding Series Electric Revenue Bonds, payable annually from 2004 to 2010 with interest ranging from 3.5% to 5.0%	47,660	—	—	47,660	16,430
2002B Refunding Series Electric Revenue Bonds, payable annually 2010 to 2018 with variable interest rates (0.98% and 1.6% as of December 31, 2003 and 2002, respectively)	50,000	—	—	50,000	—
Total bonds payable	1,263,009	—	(21,965)	1,241,044	20,860
Less unamortized discount	(43,099)	—	2,479	(40,620)	—
Plus unamortized premium	1,418	—	(617)	801	—
Bonds payable, net	$ 1,221,328	—	$ (20,103)	$ 1,201,225	$ 20,860

The bonds are special obligations of the Agency and are secured by future revenue and pledged monies and securities as provided by the bond resolution.

The bonds generally provide for early redemption beginning ten years after issuance at prices ranging from 100% to 103% of the bond principal amounts.

The Agency has advance refunded certain bond issues as described in note 10. The Agency is in compliance with its covenants under the bond indenture.

(DOLLARS IN $000s)

The following is a summary of total debt service deposit requirements for bonds outstanding at December 31, 2004:

Year	Principal	Interest	Total
2005	$ 27,943	$ 53,861	$ 81,804
2006	29,607	52,905	82,512
2007	31,208	51,306	82,514
2008	32,746	49,767	82,513
2009	34,387	48,086	82,473
2010	30,180	52,267	82,447
2011	28,673	53,836	82,509
2012	28,745	53,753	82,498
2013	40,207	42,211	82,418
2014	52,590	40,030	92,620
2015	48,820	35,785	84,605
2016	48,440	33,333	81,773
2017	50,710	31,064	81,774
2018	53,070	28,704	81,774
2019	55,790	25,981	81,771
2020	58,865	22,909	81,774
2021	50,659	31,113	81,772
2022	50,345	31,426	81,771
2023	53,766	28,008	81,774
2024	68,230	13,545	81,775
2025	23,229	58,543	81,772
2026	33,012	48,759	81,771
2027	33,198	48,577	81,775
2028	33,532	48,241	81,773
2029	33,912	47,860	81,772
2030	34,415	47,360	81,775
2031	38,758	43,016	81,774
2032	67,500	11,123	78,623
2033	22,574	4,397	26,971
	$ 1,195,111	$ 1,137,766	$ 2,332,877

The debt service deposit requirements for principal differ from total long-term debt outstanding at December 31, 2004, because the principal payment of $24,400, which is due January 1, 2005 was deposited during 2004. All principal payments are due on January 1 of the year subsequent to the deposit requirement.

10. IN-SUBSTANCE DEBT DEFEASANCE

In prior years, the Agency defeased in-substance certain Electric Revenue Bonds by placing the proceeds of new bonds in an irrevocable trust fund to provide for future debt service payments on the old debt. Accordingly, the trust account asset and the liability for the defeased bonds are not included in the accompanying financial statements. On December 31, 2004, $221,690 of the bonds are considered defeased in-substance.

11. RESERVE FOR DECOMMISSIONING

The Agency has an obligation for decommissioning the Catawba Nuclear Station after the expiration of its operating licenses. The Agency is in compliance with Nuclear Regulatory Commission requirements for funding future decommissioning costs. Since 1985, the Agency has been making regular deposits to segregated decommissioning accounts. Deposits pertaining to contaminated portions of the Project are held by a trustee. The Agency has custody of funds set aside to decommission noncontaminated portions of the project. As of December 31, 2004 and 2003, the fair values of the Agency's assets that are legally restricted for purposes of settling the decommissioning obligation are $49,628 and $47,670, respectively.

During 2003, Duke received a 19-year extension of the operating license for Catawba Unit 1 and a 17-year extension of the operating license for Catawba Unit 2 through 2043. In connection with the license extensions, the Agency received an updated decommissioning study. The study estimates total decommissioning costs of $999,313 in 2003 dollars and presumes the Catawba Nuclear Station will be decommissioned as soon as possible following the expiration of its operating licenses in 2043. The Agency used the estimates from this study to determine its decommissioning liability to be recorded in accordance with SFAS No. 143.

(DOLLARS IN $000s)

The Agency used the following assumptions in determining its reserve for decommissioning:

Period in which decommissioning liability was incurred	1985
Agency's share of decommissioning costs per study (in 2003 dollars)	$ 124,914
Estimated inflation	3%
Credit adjusted risk-free interest rate	5%
Estimated life of corresponding asset	59 years

On January 1, 2003, the Agency recorded an obligation and corresponding asset of $22,900 as of 1985, the date the liability was incurred. Concurrently, the Agency recorded accretion of the obligation and depreciation expense of $32,211 and $6,793, respectively, for the period from the date the Agency incurred the liability through January 1, 2003, and removed its existing reserve for decommissioning of $43,072 as of January 1, 2003. This resulted in a net cumulative-effect-type adjustment of $4,068 in the statement of revenues, expenses, and changes in net assets.

Following is a rollforward of the reserve for decommissioning for the year ended December 31, 2004 and 2003:

	2004	2003
Reserve for decommissioning at January 1	$ 57,867	$ 55,111
Accretion expense (decommissioning)	2,894	2,756
Reserve for decommissioning at December 31	$ 60,761	$ 57,867

Depreciation expense on the corresponding asset was $388 for both the years ended December 31, 2004 and 2003, and is included in depreciation expense in the accompanying statements of revenues, expenses, and changes in net assets.

12. EMPLOYEE BENEFIT PLANS

The Agency maintains a defined contribution money purchase plan in compliance with Section 401(a) of the Internal Revenue Code. On behalf of all full-time employees, the Agency contributes 10% of base salary into the money purchase plan. Agency contributions totaled $91 and $82 in 2004 and 2003, respectively. Employee contributions may also be made to the Plan, providing combined employer and employee annual contributions do not exceed 25% of eligible employee compensation, or $30, whichever is less.

The Agency also maintains a deferred compensation plan under Section 457 of the Internal Revenue Code. From time to time, on behalf of selected employees, the Agency contributes to the deferred compensation plan. Employee contributions may also be made to the deferred compensation plan providing combined employer and employee annual contributions do not exceed certain limitations.

Assets of the money purchase and deferred compensation plans are held by Prudential Financial, administrator and trustee for the Agency, for the exclusive benefit of the employees.

13. DISCLOSURES REGARDING FAIR VALUE OF FINANCIAL INSTRUMENTS

Statement of Financial Accounting Standards No. 107 (SFAS No. 107), *Disclosure About Fair Value of Financial Instruments*, requires disclosure of fair value information about financial instruments whether or not recognized in the balance sheet, for which it is practicable to estimate fair value. Fair value estimates are made as of a specific point in time based on the characteristics of the financial instruments and the relevant market information. Where available, quoted market prices are used. In other cases, fair values are based on estimates using present value or other valuation techniques. These techniques involve uncertainties and are significantly affected by the assumptions used and the judgments made regarding risk characteristics of various financial instruments, discount rates, prepayments, estimates of future cash flows, future expected loss experience and other factors. Changes in assumptions could significantly affect these estimates. Derived fair value estimates cannot be substantiated by comparison to independent markets and, in many cases, may or may not be realized in an immediate sale of the instrument.

(DOLLARS IN $000s)

Under SFAS No. 107, fair value estimates are based on existing financial instruments without attempting to estimate the value of anticipated future business and the value of the assets and liabilities that are not financial instruments. Accordingly, the aggregate fair value amounts presented do not represent the underlying value of the Agency.

The following describes the methods and assumptions used by the Agency in determining carrying value and estimated fair value of financial instruments:

A. *Cash*
Carrying value equals estimated fair value.

B. *Marketable Debt Securities*
Estimated fair value, which is the carrying value, of all marketable debt securities is derived from quoted market prices.

C. *Derivative Financial Instruments*
Estimated fair value of derivative financial instruments is derived from current market pricing models.

D. *Participant Accounts Receivable, and Other Accounts Receivable*
Carrying amount approximates fair value due to the short-term nature of these instruments.

E. *Long-term Debt*
Carrying value of long-term debt coupon securities includes par, less unaccreted discounts, plus unamortized premiums, plus accrued interest payable. Carrying value also includes Capital Appreciation Term Bonds valued at original price plus accrued interest payable.

Estimated fair value of all long-term debt securities is derived from quoted market prices and includes accrued interest.

The estimated fair values of the Agency's long-term debt with carrying values are different from their estimated fair values at December 31, 2004 and 2003 as follows:

ESTIMATED FAIR VALUE	2004		2003	
	Carrying amount	Estimated fair value	Carrying amount	Estimated fair value
1986 Electric Revenue Refunding Bonds	$ 18,505	$ 21,875	$ 28,138	$ 30,729
1986A Electric Revenue Refunding Bonds	—	—	96,616	106,881
1988 Electric Revenue Refunding Bonds	17,245	23,389	25,695	53,260
1988A Electric Revenue Refunding Bonds	10,815	13,063	13,115	24,667
1991 Electric Revenue Refunding Bonds	104,045	123,074	125,746	151,482
1991A Electric Revenue Refunding Bonds	59,628	67,413	99,896	114,553
1992 Electric Revenue Refunding Bonds	—	—	20,468	20,821
1993 Electric Revenue Refunding Bonds	64,123	71,602	72,947	82,339
1996A Electric Revenue Refunding Bonds	—	—	69,685	70,058
1996B Electric Revenue Refunding Bonds	99,644	104,393	115,271	127,057
1996C/D Electric Revenue Refunding Bonds	11,015	11,000	100,086	100,086
1997A Electric Revenue Refunding Bonds	31,745	31,700	31,727	31,727
1997B/C Electric Revenue Refunding Bonds	97,252	97,100	97,200	97,200
1998A Electric Revenue Refunding Bonds	161,293	167,425	161,066	171,335
1999A Electric Revenue Refunding Bonds	97,950	99,648	97,787	100,078
2002A Electric Revenue Refunding Bonds	11,680	11,435	48,735	49,449
2002B Electric Revenue Refunding Bonds	—	—	50,105	50,049
2004A-1 Electric Revenue Refunding Bonds	104,848	93,087	—	—
2004A-2 Electric Revenue Refunding Bonds	104,918	114,674	—	—
2004B Electric Revenue Refunding Bonds	240,735	240,400	—	—
	$ 1,235,441	$ 1,291,278	$ 1,254,283	$ 1,381,771

14. NUCLEAR INSURANCE

Nuclear Insurance. Duke Energy owns and operates the McGuire and Oconee Nuclear Stations with two and three nuclear reactors, respectively, and operates and has a partial ownership interest in the Catawba Nuclear Station with two nuclear reactors. Nuclear insurance coverage is maintained in three program areas: liability coverage; property, decontamination and decommissioning coverage; and business interruption and/or extra expense coverage. Certain expenses associated with nuclear insurance premiums paid by Duke Energy are reimbursed by the other joint owners of the Catawba Nuclear Station.

Pursuant to the Price-Anderson Act, Duke Energy is required to insure against public liability claims resulting from nuclear incidents to the full limit of liability of approximately $10.8 billion.

Primary Liability Insurance. Duke Energy has purchased the maximum available private primary liability insurance as required by law. As of January 1, 2003, $300 million in private primary liability insurance became available and Duke Energy purchased that amount along with a like amount to cover certain worker tort claims.

Excess Liability Insurance. This policy currently provides approximately $10.5 billion of coverage through the Price-Anderson Act's mandatory industry-wide secondary insurance program of risk pooling. The $10.5 billion of coverage is the sum of the current potential cumulative retrospective premium assessments of $101 million per licensed commercial nuclear reactor. This $10.5 billion would be increased by $101 million as each additional commercial nuclear reactor is licensed, or reduced by $101 million for nuclear reactors that are no longer operational and may be exempted from the risk pooling insurance program. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation.

If such an incident should occur and public liability damages exceed primary insurance, licensees may be assessed up to $101 million for each of their licensed reactors, payable at a rate not to exceed $10 million a year per licensed reactor for each incident. The $101 million amount is subject to indexing for inflation and may be subject to state premium taxes. If retrospective premiums were to be assessed, the Agency and each other joint owner of Catawba would be obligated to assume its pro rata share of such assessment.

Duke Energy is a member of Nuclear Electric Insurance Limited (NEIL), which provides property and business interruption insurance coverage for Duke Energy's nuclear facilities under the following three policy programs:

Primary Property Insurance. This policy provides $500 million of primary property damage coverage for each of Duke Energy's nuclear facilities.

Excess Property Insurance. This policy provides excess property, decontamination, and decommissioning liability insurance in the following amounts: $2.25 billion for the Catawba Nuclear Station and $2.0 billion each for the Oconee and McGuire Nuclear Stations.

Business Interruption Insurance. This policy provides business interruption and/or extra expense coverage resulting from an accidental outage of a nuclear unit. Each unit of the McGuire and Catawba Nuclear Stations is insured for up to $3.5 million per week and the Oconee Nuclear Station units are insured for up to $2.8 million per week. Coverage amounts per unit decline if more than one unit is involved in an accidental outage. Initial coverage begins after a 12-week deductible period and continues at 100% for 52 weeks and 80% for the next 110 weeks.

If NEIL's losses ever exceed its reserves for any of the above three programs, Duke Energy will be liable for assessments of up to ten times its annual premiums. The current potential maximum assessments are as follows: Primary Property Insurance – $35 million; Excess Property Insurance – $44 million; Business Interruption Insurance – $29 million.

The other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the Price-Anderson Act's excess secondary insurance program of risk pooling or the NEIL policies.

15. DERIVATIVE FINANCIAL INSTRUMENTS

The Agency has only limited involvement with derivative financial instruments.

The Agency is party to four interest rate swap agreements. Two of the interest rate swap agreements were originally scheduled to terminate in January 2024. The Agency's objective for entering into these interest rate swap agreements was to maximize income. Under these fixed to variable interest rate swaps, PMPA received a fixed rate of 5.93% through December 31, 2004, while paying a variable rate based on the BMA Municipal Swap Index. The notional amount of each of these agreements was $51,908. In January 2003, the Agency amended the agreements to lock in at 2.09% the variable interest rate paid by the Agency until December 31, 2004. The agreements were cancelled on January 1, 2005.

The Agency is party to a third interest rate swap agreement with a termination date of January 1, 2021. This swap is designed to mitigate interest rate risk of outstanding variable rate debt during rising interest rate periods and augment expected income during falling interest rate periods. PMPA receives a floating LIBOR rate and pays a floating variable rate based on the BMA Municipal Swap Index. The notional amount of this agreement is $100,000. The Agency posted marketable debt securities with par value of $2,300 as collateral on this swap at December 31, 2004.

The Agency is also party to a fourth interest rate swap agreement with a termination date of January 1, 2034. The objective of this swap is to achieve a lower fixed rate of interest on PMPA's debt. Under this floating to fixed transaction, PMPA receives a variable interest rate based on the BMA Municipal Swap Index on a notional amount of $60 million and pays a low rate of 3% for the first twenty years and a higher rate of 16% for the last ten years of the swap life. The average rate that PMPA will pay over the life of the swap will be 4.84%. The swap is designed to push debt service out in later years to produce overall level debt service.

The fair value of the four interest rate swap agreements was approximately $8,286 (liability) and $1,009 (asset) at December 31, 2004 and 2003, respectively. Current market pricing models were used to estimate fair value of interest rate swap agreements. The fluctuation in the fair value of the interest rate swaps was a decrease of $9,295 and $1,459 in 2004 and 2003, respectively, and is included in net decrease in fair value of investments and derivative instruments in the statements of revenues, expenses, and changes in net assets. Total net income from the interest rate swaps was $3,539 and $3,951 in 2004 and 2003, respectively, and is included in other expense, net, in the statements of revenues, expenses, and changes in net assets.

In October 2000, the Agency entered into a forward delivery agreement with a term of five years. The Agency's objective for entering into this forward delivery agreement is to maximize investment income. The agreement entitles the Agency to receive interest at a fixed rate of 6.4825% on scheduled monthly deposits into certain debt service principal and interest accounts. The fair value of the forward delivery agreement was approximately $772 and $1,929 at December 31, 2004 and 2003, respectively. The fluctuation in the fair value of the forward delivery contract was a decrease of $1,157 and $741 in 2004 and 2003, respectively, and is included in net decrease in fair value of investments and derivative instruments in the statements of revenues, expenses, and changes in net assets. Total income from the forward delivery agreement was $1,158 and $1,165 in 2004 and 2003, respectively, and is included in interest income in the statements of revenues, expenses, and changes in net assets.

By using derivative instruments the Agency exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of the derivative contract is positive, the counterparty owes the Agency, which creates repayment risk for the Agency. When the fair value of a derivative contract is negative, the Agency owes the counterparty and, therefore, does not possess repayment risk. The Agency minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties.

Market risk is the adverse effect on the value of financial instruments that results from a change in interest rates. The market risk associated with interest rate contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken.

Supplementary Information

Schedule of Revenue and Expenses Schedule 1

PER THE BOND RESOLUTION AND OTHER AGREEMENTS • YEAR ENDED DECEMBER 31, 2004 • (DOLLARS IN $000s)

	Actual revenues and expenses	Budgeted revenues and expenses	Actual over (under) budget
Revenue:			
Sales of electricity to Participants	$ 127,393	$ 130,690	$ (3,297)
Sales of electricity to Duke	9,102	8,743	359
Sales of electricity to others	8,693	6,166	2,527
Interest income	14,582	15,829	(1,247)
Other	1,076	1,078	(2)
Total revenue	$ 160,846	$ 162,506	$ (1,660)
Expenses:			
Catawba operating expenses:			
Operation and maintenance	$ 23,158	$ 23,000	$ 158
Nuclear fuel	6,294	7,000	(706)
Purchased power – Duke	8,663	8,434	229
Payments in lieu of taxes	4,400	3,988	412
Interconnection services:			
Purchased power:			
Duke	14,822	10,886	3,936
Participants	8,601	8,327	274
Other	244	288	(44)
Transmission services	4,652	5,144	(492)
Distribution services	1,196	1,274	(78)
Administrative and general:			
Agency	4,069	4,227	(158)
Duke	10,579	11,178	(599)
Other	282	892	(610)
Special funds deposits (withdrawals):			
Bond fund:			
Deposits from revenues	88,999	88,353	646
Liquidity facility fees	992	819	173
Reserve and Contingency fund:			
Deposits from revenue	9,629	8,772	857
Capital additions	(5,801)	(4,986)	(815)
Transfer excess funds	(3,828)	(3,786)	(42)
Decommissioning fund:			
Deposits from revenue	861	1,725	(864)
Interest income (1)	1,857	2,190	(333)
Revenue fund:			
Working capital	(6,471)	(1,126)	(5,345)
Fuel	(7,606)	(6,473)	(1,133)
Rate stabilization:			
Interest income (1)	5,320	5,234	86
Deposits (draws)	(25,021)	(25,021)	—
Supplemental power reserve:			
Interest income (1)	365	300	65
Transfer excess funds	(365)	(300)	(65)
Other capital transactions:			
Bond proceeds	(446,307)	—	(446,307)
Bond payments	455,836	—	455,836
Debt issuance	37,302	—	37,302
Excess funds	(46,168)	—	(46,168)
Plant additions:			
Reserve and contingency fund	5,801	4,986	815
General plant	47	101	(54)
Transmission plant	838	383	455
Distribution plant	—	224	(224)
Fuel acquisitions	7,606	6,473	1,133
Total expenses	$ 160,846	$ 162,506	$ (1,660)

(1) Included in "Revenue: Interest Income."

See accompanying independent auditors' report.

Schedule of Revenue and Expenses Schedule 2

PER THE BOND RESOLUTION AND OTHER AGREEMENTS • YEAR ENDED DECEMBER 31, 2004 • (DOLLARS IN $000s)

	Funds							
	Revenue		Operating	Bond				
	Working capital	Rate stabilization	Fuel account	Principal interest retire	Reserve	Reserve and contingency	Decommission	Supplemental power
Balances at beginning of year:								
Assets	$ 93,360	$ 113,680	$ 28,561	$ 50,051	$ 78,974	$ 7,897	$46,539	$ 15,000
Liabilities	(8,688)							
Net	84,672							
Project revenues:								
Participants – electric (1)	127,393							
Participants – facilities rent (1)	1,043							
Participants – other (1)	34							
Duke Power – electric (1)	9,102							
Other – surplus electric (1)	8,693							
Interest income (1)	7,040	5,320					1,857	365
Project costs (see note):								
Operations and maintenance (2)	(23,158)							
Fuel (3)	(6,294)		6,294					
Purchased power – Duke (2)	(8,663)							
Decommissioning (3)	(861)						861	
General and administration (2)	(13,095)							
Payments in lieu of taxes (2)	(4,371)							
Other (2)	(282)							
Debt service (3)	(87,782)			87,782				
Liquidity facility fee (3)	(992)			992				
Bond retirement (3)	(1,217)			1,217				
Reserve and contingency (3)	(9,629)					9,629		
Supplemental power costs:								
Purchased power – Duke (2)	(14,822)							
Purchased power – Participant (2)	(8,601)							
Purchased power – Other (2)	(244)							
Transmission services (2)	(4,652)							
Distribution services (2)	(1,196)							
General and administration (2)	(1,554)							
Payments in lieu of taxes (2)	(29)							
Other fund changes:								
Transfers in (out):								
Rate stabilization (3)	25,021	(25,021)						
Excess funds (3)	4,193					(3,828)		(365)
Reimbursement (3)	5,801					(5,801)		
Payments:								
Debt retire/interest (2)				(80,098)				
Capital additions (2)	(6,686)		(7,606)					
Debt refunding:								
New issue proceeds	446,307							
Excess funds	46,168	(23,081)		(16,790)	(5,725)	(572)		
Old issue proceeds	(455,836)							
Cost of issue	(37,302)							
Balances at December 31, 2004	$ 78,201	$ 70,898	$ 27,249	$ 43,154	$ 73,249	$ 7,325	$49,257	$ 15,000
Assets	88,908							
Liabilities	$(10,707)							

(1) Deposited in appropriate fund

(2) Paid to third parties from Revenue Fund (Working Capital) to the Operating Fund and actual disbursements are made from the Operating Fund.

(3) Transfers between funds

See accompanying independent auditors' report.

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