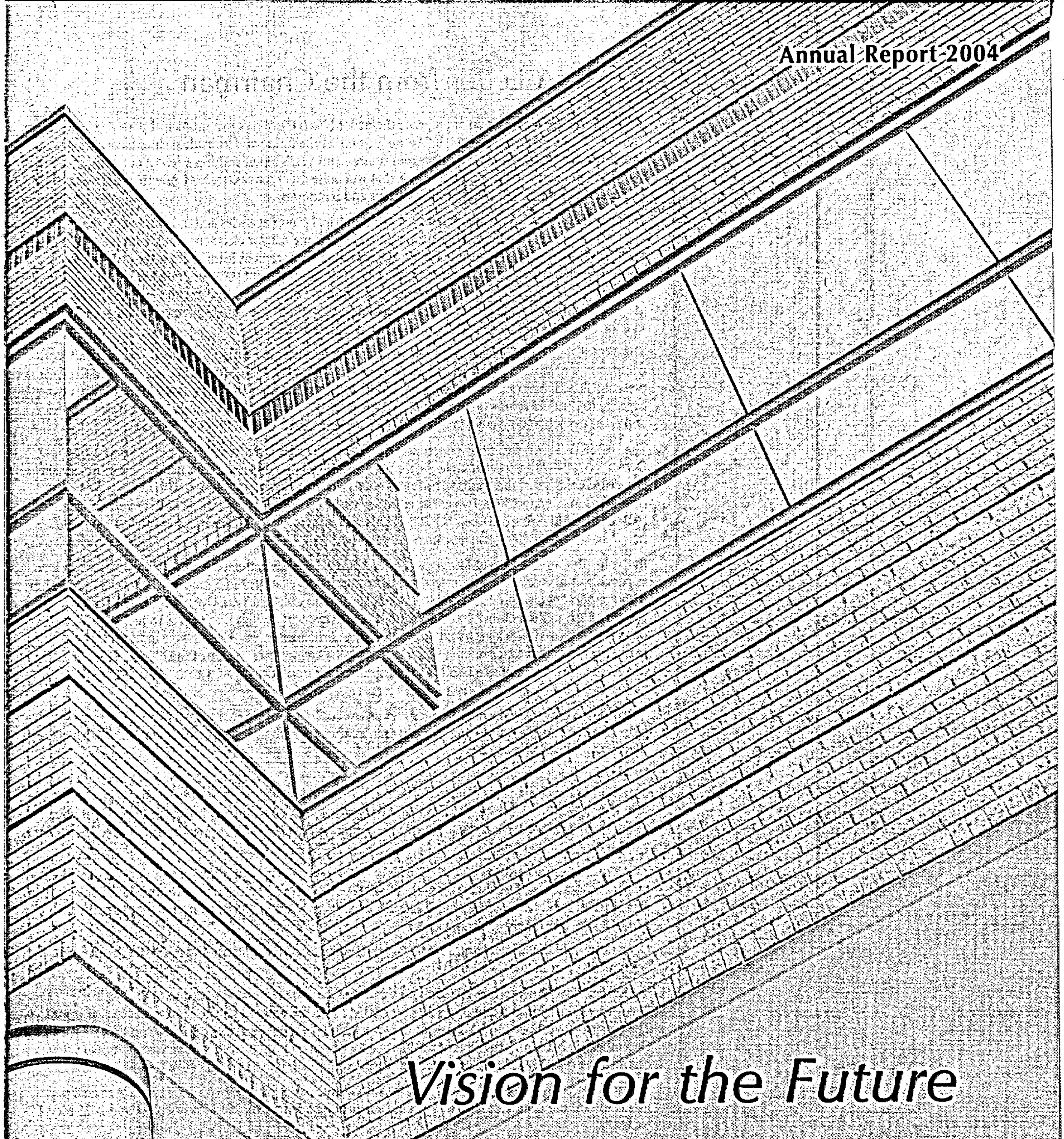
Annual Report 2004



# Vision for the Future

North Carolina Municipal Power Agency Number 1 / North Carolina Eastern Municipal Power Agency ELECTRICITIES

Frederick E. Turnage
*Chairman*

"For almost 40 years ElectriCities has served our municipal power agencies and our cities with innovative, cost-saving services that benefit our communities and ensure reliable electricity."

# A Letter from the Chairman

A "Vision for the Future" is an appropriate theme for North Carolina's two municipal power agencies as we end 2004 and look forward to 2005. We are focused on the future and individual cities have undertaken initiatives that will provide for a prosperous future. This year's report features a few of our cities and how they have implemented plans and projects that will poise them for electric load growth and develop their communities for the well-being of their citizens and businesses.

For almost 40 years ElectriCities has served our municipal power agencies and our cities with innovative, cost-saving services that benefit our communities and ensure reliable electricity. And, I am pleased to report that with the excellent leadership of our CEO, his senior management team and a dedicated staff, both power agencies experienced outstanding years in 2004. Management staff continued to work to find innovative solutions, achieve cost savings and implement new programs. Our cities engaged in active grassroots and advertising efforts to increase political strength in the state legislature as well as in Congress in efforts to better influence positive outcomes on critical issues.

The ElectriCities Board of Directors approved a comprehensive power supply proposal with a number of companies for North Carolina Municipal Power Agency Number 1 (NCMPA1) that will deliver a five-year net present value savings of over $30 million. And in 2003, the Board of Directors took action to increase our capacity to conduct transactions, from 400MW to 832MW, resulting in an elimination of reserve capacity and energy purchases, together saving NCMPA1 approximately $6.5 million for the year.

The NCMPA1 Board of Commissioners and the Board of Directors authorized refunding bond issues in December 2004 with expected savings over the transactions of $19.5 million in net present value of debt service over the life of the bonds. The bonds were to be issued at various times, with the first being completed in January 2005. Two credit rating agencies responded to the actions and trends and upgraded NCMPA1's credit rating in December 2004. This action is critical as it leads to lower interest rates paid on new debt issued and demonstrates financial stability.

In the North Carolina Eastern Municipal Power Agency (NCEMPA), the focus was on keeping rates as low as possible. A new procedure to review contracts and the development of a mutually beneficial partnership with Progress Energy Carolinas combined to make 2004 an excellent year. Overall, NCEMPA achieved cost savings of $55 million during 2004. Demand-side management savings for the year were $33 million, savings that proved critical to maintaining NCEMPA participant rates. A bond issue in June 2004 for refunding resulted in $21.1 million of net present value savings over the life of the bonds. This refunding was accomplished in part as a result of MBIA approval for insurance capacity received in 2003, the first new capacity for NCEMPA in a number of years.

A new process was developed to monitor and review coal costs for NCEMPA's coal plants. These new procedures will enable staff to monitor and anticipate changes to the cost of coal as conditions change in the world and national markets.

NCEMPA continues to work very closely with Progress Energy Carolinas, as a business partner in the operation of the generating facilities and with supplemental power supply contracts. The relationship between NCEMPA and Progress Energy Carolinas has proven to be mutually beneficial to both parties and to our member cities. Constant communications improves the flow of information which effectively reduces NCEMPA's operating costs.

Target marketing, advertising and the pursuit of economic development leads led to a number of announcements for business and industry this year. NCMPA1 added over $90 million in investment, 812 new jobs and 8MW of new electric load, while NCEMPA achieved more than $75 million in investment, the addition of 1,017 jobs and 13MW of electric load.

Operations in both NCMPA1 and NCEMPA-owned generation were outstanding in 2004. The plants had a productive year in 2004, keeping power agency costs as low as possible.

In October 2004, Progress Energy Carolinas submitted a license renewal application to the Nuclear Regulatory Commission requesting a 20-year operating license renewal for the Brunswick Nuclear Plant. The current 40-year operating license for Brunswick Unit 1 expires September 8, 2016 and Unit 2 expires December 27, 2014. An extension of the lifetime for operations will provide substantial additional value to our member cities and our citizens. Nuclear plants continue to provide clean, reliable and affordable energy.

Financially, the health of our power agencies and ElectriCities is good. We continue to make annual payments toward our debt. Our rates will not include debt payments after 2019 for NCMPA1 and 2025 for NCEMPA.

Our staff continues to engage in a number of strategic communications and advertising programs to help cities communicate with citizens; maintain a focus on safety and training programs; and, further develop a legislative and grassroots program that has grown as more and more cities engaged on state and federal legislative issues.

All of the elements of a bright and prosperous future are within our grasp. The path for the next 40 years will be set by our actions today and your continued support and cooperation.


Jesse C. Tilton, III
*CEO*

"We continue to look for and find the most cost effective ways to provide electricity to our citizens and businesses while ensuring a high quality of service and reliability."

# A Letter from the CEO

I am pleased to present this report to the cities and the citizens in the cities that comprise North Carolina's two municipal power agencies, North Carolina Municipal Power Agency Number 1 (NCMPA1) and the North Carolina Eastern Municipal Power Agency (NCEMPA). Our 51 cities, together and individually, are on the cutting edge of programs and plans that will ensure their success in the future. This report captures that spirit by highlighting examples of six of our cities and in the results of a year of success.

Both power agencies had outstanding years in 2004. Management staff, working with the Board of Directors, the power agency Boards of Commissioners and the cities, implemented programs, services and generated cost savings that will have a positive and lasting effect on the cities well into the future.

Since 2001, the power agencies' economic development efforts contributed to the state economy, providing more than $1 billion in investments through new and expanded business and industry and providing more than 10,000 jobs in our member cities. This year, many NCMPA1 cities celebrated economic development successes with more than $90 million in investment, 812 new jobs and 8MW of new electric load. In NCEMPA, the agency cities achieved more than $75 million in investment, the addition of 1,017 jobs and 13MW of electric load.

Over the past six years, the power agencies have reduced the debt associated with their plant ownership percentages by almost $1 billion. Refinancings over the past five years yielded more than $150 million in savings over the life of the refinanced bonds, net present value savings for NCEMPA of $73.6 million and for NCMPA1, $96.5 million.

This past year, in NCMPA1, comprehensive power supply contracts and increased transaction capacity of 432MW resulted in significant savings. These cost-saving actions, a positive outlook and positive trends resulted in credit rating upgrades. In NCEMPA, the focus was on efforts to keep rates as low as possible. Demand-side management savings in addition to other cost-savings initiatives, helped hold down rate increases. These savings proved critical to maintaining NCEMPA participant rates. New contract procedures and communications enacted will significantly affect accuracy in contract billing and result in cost-savings. In both agencies, bond refundings led to long term savings.

Electric load growth in our cities remains a top priority for the present and the future, and as the economy in the state continues to improve, challenges remain. We continue to work to help our cities target business and industry that is compatible with their area. We continue to look for and find the most cost effective ways to provide electricity to our citizens and businesses while ensuring a high quality of service and reliability.

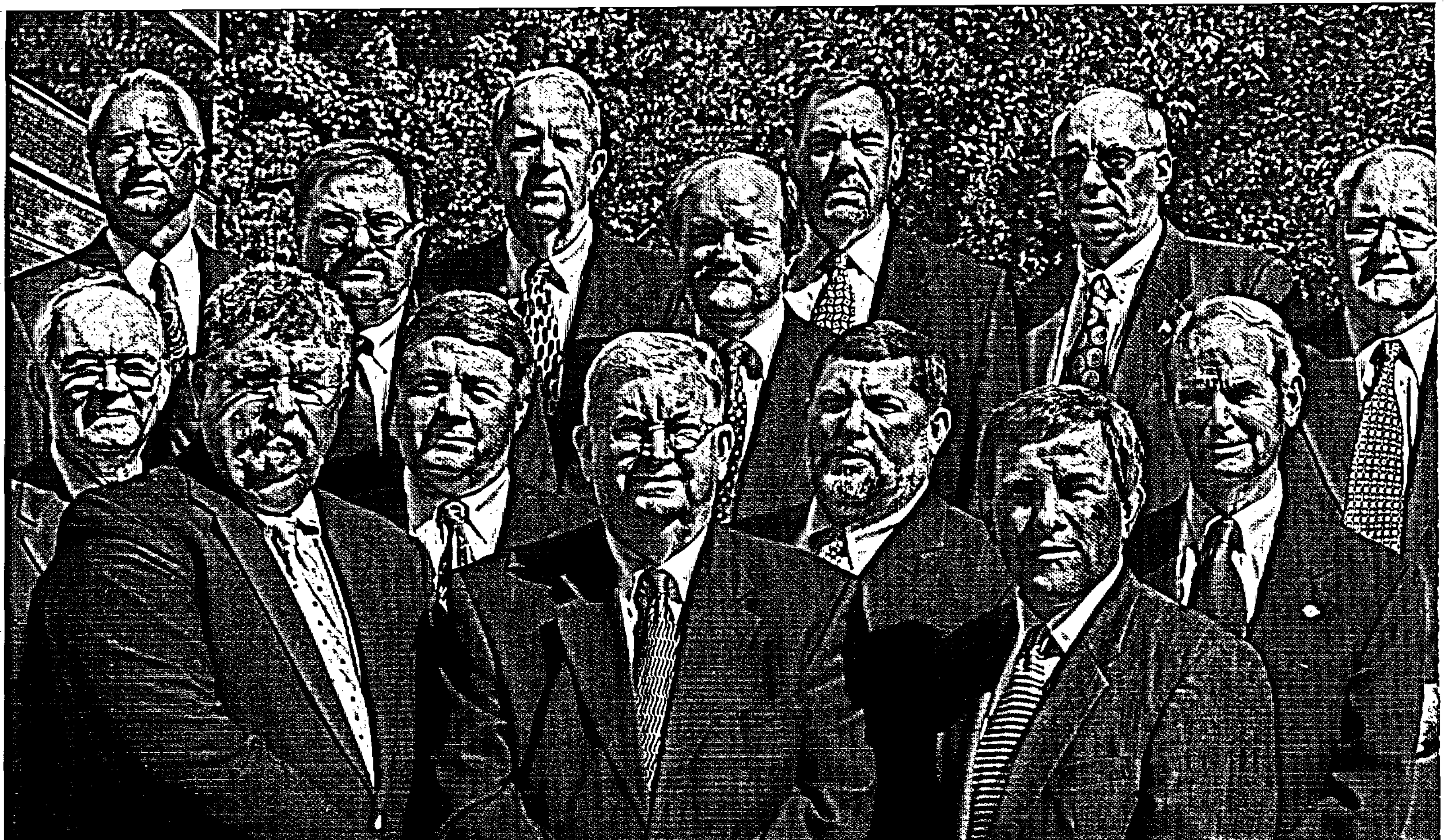
Without the enactment of a comprehensive energy bill in Congress last year, we again actively participated in the legislative process as part of a coordinated effort with other organizations across the country. Our primary interest remains increased reliability, decreased congestion and increased stability of the electric grid. We worked to support national energy provisions that increase reliability and are fair to all entities that use the grid. And, at the NC General Assembly, our efforts continue to ensure that no legislation is enacted that will negatively affect electric load growth in our cities. Over the past year, we have significantly increased our political strength in partnership with Mayors, Council, Commission members and city staff. Strategic advertising focusing on our key messages in partnership with our cities reinforces our messages in our communities and across the state.

During 2004, North Carolina's major electric load-serving entities, including Duke Power, ElectriCities of NC, North Carolina Electric Membership Corporation and Progress Energy Carolinas, Inc., developed a collaborative transmission planning process. In April 2004, the North Carolina Utilities Commission (NCUC) initiated a public meeting to hear the concerns regarding transmission issues in North Carolina. The NCUC requested that we work together to address the issues raised. In response, the aforementioned organizations and companies began meeting to develop a long-term comprehensive transmission planning process for North Carolina, facilitated by an independent third party with input from other market participants and designed to preserve reliability as well as enhancing access to a variety of generation resources.

In December 2003, we were excited to announce a license renewal for NCMPA1's co-owned nuclear plant, Catawba. In October 2004, Progress Energy Carolinas submitted a license renewal application to the Nuclear Regulatory Commission requesting a 20-year operating license renewal for the Brunswick Nuclear Plant. Now, NCEMPA has the potential to be the beneficiary of substantial additional value to its member cities through clean, reliable and affordable nuclear energy, well into the future.

Safety remains a top priority of our cities. Member cities are implementing several new enhancements to increase the overall effectiveness of city safety programs. Our safety and training program received the NC Labor Commissioner's Special Recognition Award for outstanding contributions in the development and support of public power's statewide apprenticeship program.

Together with the ElectriCities Board of Directors, the NCMPA1 and NCEMPA Boards of Commissioners and the leadership across the state in our cities, our staff remains committed to providing the highest level of customer service, reliable and cost-effective electricity. Our strength is our unity whether it is regulatory matters, issues in the state legislature and Congress or economic development, safety and training, purchasing and any of the other services we provide. Our future has been improved by the vision and accomplishments of this and recent years.



Front row (L to R) **Hicks** *Secretary*, **Turnage** *Chairman* , **Hayes** *Vice Chairman*
Second row **Dickson, Willoughby, Noble, Thomas** Third row **Puckett, Jones, Cox**
Fourth row **Seamone, McGuinn, Wofford, Smith**

## 2004 BOARD OF DIRECTORS

**Frederick E. Turnage**
*Chairman*, Rocky Mount

**Barry C. Hayes**
*Vice Chairman*, Granite Falls

**Richard N. Hicks**
*Secretary*, Farmville

**Jerry E. Cox**
Huntersville

**Walter W. "Dub" Dickson**
Gastonia

**Roger G. Jones**
Greenville

**J. William McGuinn, Jr.**
High Point

**Samuel W. Noble, Jr.**
Tarboro

**Ralph E. Puckett, Jr.**
New Bern

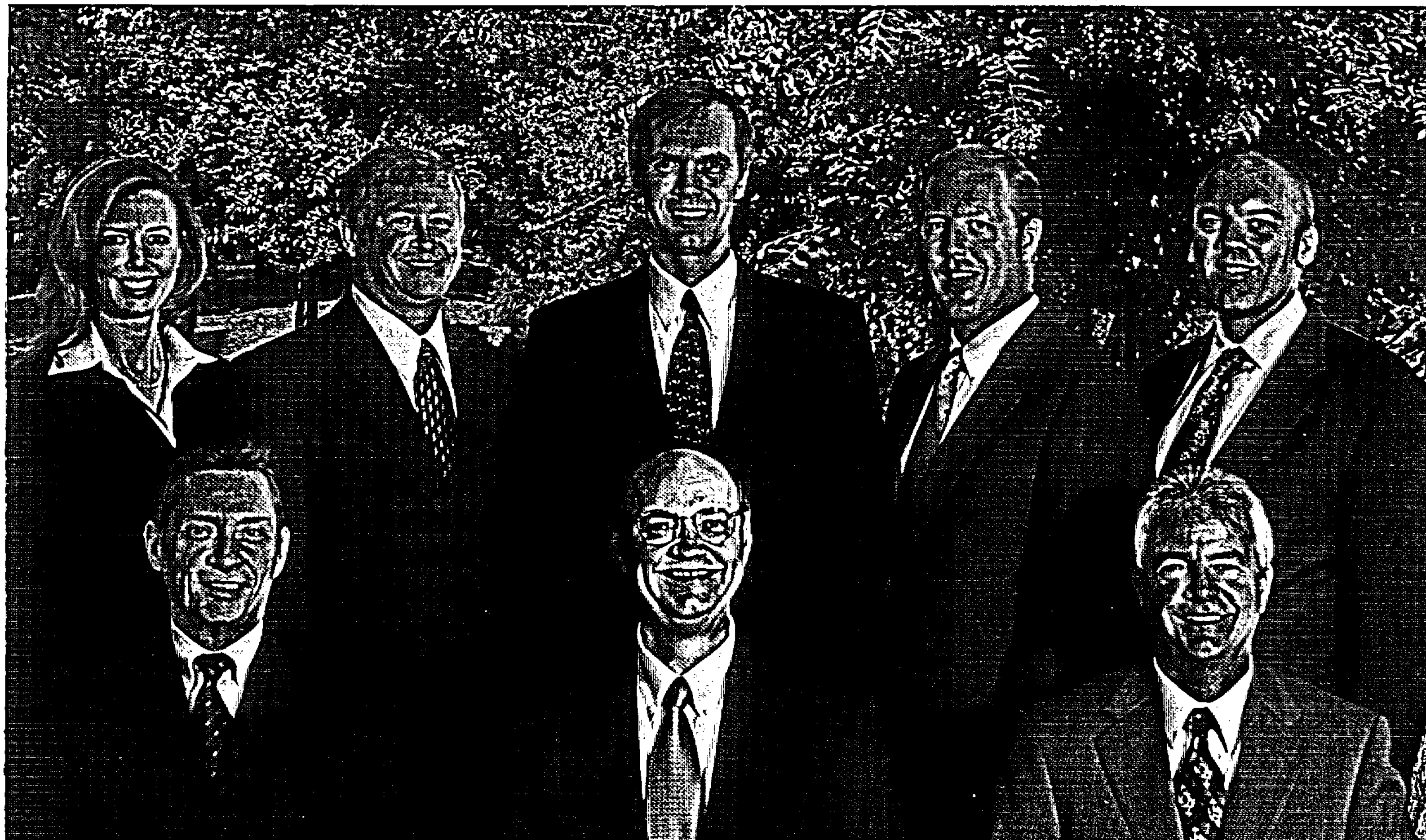
**William A. Seamone**
Concord

**Robert J. Smith**
Monroe

**Richard L. Thomas**
Lexington

**R. L. Willoughby**
Raleigh

**Milton R. "Milt" Wofford**
Fayetteville



Front row (L to R) **Conyers, Tilton, Hubert**
Back row **Bonds, Raber, Shelton, Otersen, Norris**

## MANAGEMENT

**Jesse C. Tilton, III**
Chief Executive Officer

**Arthur L. Hubert, Jr.**
*Chief Operating Officer

**Al M. Conyers**
*Chief Financial Officer

**Jeanne Milliken Bonds**
*Division Director, Political Action and Communications

**Clay A. Norris**
*Division Director, Planning

**Mark H. Otersen**
Division Director, Marketing and Member Services

**Kenneth M. Raber**
Division Director, NCEMPA Operations

**Steve R. Shelton**
Division Director, NCMPA1 Operations

**Report directly to the CEO*

# ELECTRICITIES MEMBERSHIP

| City | Established | Customers |
|---|---|---|
| Abbeville, SC | 1905 | 3,584 |
| Albemarle | 1910 | 11,496 |
| Apex | 1917 | 10,475 |
| Ayden | 1916 | 3,695 |
| Bamberg, SC | 1905 | 1,928 |
| Bedford, VA | 1899 | 6,647 |
| Belhaven | 1920 | 1,116 |
| Bennettsville, SC | 1903 | 4,775 |
| Benson | 1913 | 1,802 |
| Bostic | 1920 | 185 |
| Camden, SC | 1902 | 9,219 |
| Cherryville | 1906 | 2,926 |
| Clayton | 1913 | 4,227 |
| Clinton, SC | 1907 | 4,110 |
| Concord | 1904 | 24,573 |
| Cornelius | 1916 | 2,309 |
| Dallas | 1925 | 3,000 |
| Danville, VA | 1886 | 41,910 |
| Drexel | 1926 | 1,183 |
| Easley, SC | 1911 | 12,541 |
| East Carolina University | NA | University |
| Edenton | 1908 | 3,940 |
| Elizabeth City | 1926 | 10,058 |
| Elizabeth City State Univ | NA | University |
| Enfield | Prior to 1940 | 1,448 |
| Farmville | 1910 | 2,949 |
| Fayetteville | 1905 | 70,219 |
| Forest City | 1910 | 4,182 |
| Fountain | 1903 | 341 |
| Fremont | 1918 | 862 |
| Gaffney, SC | 1907 | 7,461 |
| Gastonia | 1900 | 25,200 |
| Granite Falls | 1916 | 2,354 |
| Greenville | 1905 | 53,002 |
| Greer, SC | 1914 | 14,340 |
| Hamilton | 1922 | 254 |
| Hertford | 1915 | 1,231 |
| High Point | 1893 | 37,207 |
| Hobgood | 1922 | 319 |
| Hookerton | 1907 | 431 |
| Huntersville | 1916 | 3,531 |
| Kings Mountain | 1935 | 4,271 |
| Kinston | 1897 | 12,295 |
| La Grange | 1917 | 1,538 |
| Landis | 1919 | 2,607 |

| City | Established | Customers |
|---|---|---|
| Laurens, SC | 1922 | 5,216 |
| Laurinburg | 1925 | 5,681 |
| Lexington | 1903 | 18,224 |
| Lincolnton | 1900 | 2,819 |
| Louisburg | 1906 | 1,939 |
| Lucama | 1889 | 1,151 |
| Lumberton | 1903 | 9,567 |
| Macclesfield | 1928 | 293 |
| Maiden | 1920 | 1,034 |
| Martinsville, VA | 1904 | 8,067 |
| Monroe | 1900 | 9,741 |
| Morganton | 1899 | 7,898 |
| Murphy | 1953 | 4,463 |
| New Bern | 1901 | 18,169 |
| New River Light & Power | 1915 | 7,436 |
| Newberry, SC | 1923 | 4,850 |
| Newton | 1896 | 4,266 |
| Pikeville | 1918 | 527 |
| Pinetops | 1925 | 725 |
| Pineville | 1939 | 2,452 |
| Red Springs | 1910 | 1,699 |
| Richlands, VA | 1922 | 2,590 |
| Robersonville | 1919 | 1,068 |
| Rock Hill, SC | 1911 | 29,312 |
| Rocky Mount | 1902 | 30,477 |
| Scotland Neck | 1903 | 1,731 |
| Selma | 1913 | 2,736 |
| Sharpsburg | 1920 | 1,516 |
| Shelby | 1912 | 7,990 |
| Smithfield | 1912 | 4,432 |
| Southport | 1916 | 2,239 |
| Stantonsburg | 1920 | 1,117 |
| Statesville | 1889 | 12,659 |
| Tarboro | 1897 | 5,942 |
| UNC-Chapel Hill | NA | University and 850 campus retail customers |
| UNC-Greensboro | NA | University |
| Union, SC | 1896 | 7,046 |
| Wake Forest | 1909 | 5,950 |
| Walstonburg | 1922 | 132 |
| Washington | 1905 | 12,692 |
| Waynesville | 1923 | 3,164 |
| Western Carolina University | NA | University |
| Westminster, SC | 1921 | 1,644 |
| Wilson | 1892 | 32,904 |
| Windsor | 1920 | 2,006 |
| Winterville | 1900 | 2,165 |


Karen Flanary, Melba Green and R.L. Willoughby, ElectriCities Board of Directors

## Public Power Lifetime Achievement Award

The first Public Power Lifetime Achievement Award was presented posthumously to Malcolm A. "Mack" Green on August 7, 2004 during the ElectriCities Annual Meeting. Mack was a long-time advocate, innovator, leader and friend to public power. Mack's widow, Melba, and his daughter, Karen Flanary, accepted the award.

The award recognizes significant contributions to public power in North Carolina throughout an individual's lifetime. The ElectriCities Board of Directors selects deserving individuals to receive the award which is presented during the Annual Meeting.

# ElectriCities
*and*
# Public Power Communities
*Congratulate*

All-America City

## All America Cities

Concord

Farmville
*Runner Up*

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## Public Power Communities

*Celebrating 100 years as electric providers*

Public Power
YOUR HOMETOWN ENERGY PROVIDER

Concord

Lexington

Lumberton

# *Town of* Tarboro

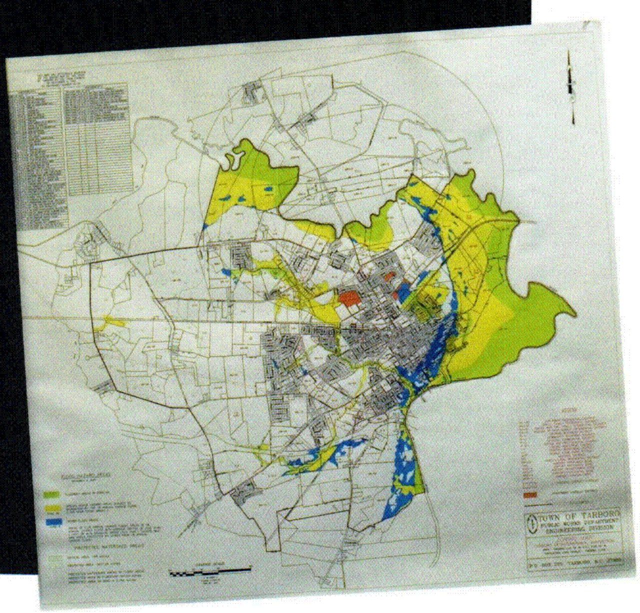
ElectriCities' Political Action and Communications staff monitors state and federal government executive and legislative activities to maintain a fair and equitable business environment. Whenever a threat or opportunity arises or is perceived, immediate action is taken to protect the interests of public power and its customers. This effort is most successful when it includes strong support at the local level from member governmental officials, local media and involved citizens. The Town of Tarboro has sought to mobilize its grassroots resources to respond quickly and effectively when needed.

As issues arose in the western part of the state between public power cities and rural electric cooperatives, it seemed likely that there would be state legislation. Town officials in Tarboro recognized that it was in their best interests to help strengthen and support any ElectriCities' response to the NC General Assembly. Tarboro began to organize and prepare a comprehensive and coordinated grassroots effort.

Mayor Donald Morris, Town Manager Sam Noble and members of the Town Council discussed the issues and prepared to meet with their local legislative representatives whenever and wherever necessary to keep them informed of the potential consequences of proposed legislation. They developed a strong association with the local newspaper, *The Daily Southerner*, to ensure that their citizens were informed. They agreed to act promptly and forcefully in the event of a threat or opportunity. Tarboro town officials recognized the need to contribute to the ElectriCities Public Power Political Action Committee in efforts to support public power champions in the legislature.

And throughout the year, as debate continued in Washington, DC on the Federal Energy Bill, Tarboro officials participated in National League of City and North Carolina League of Municipality events with the North Carolina Congressional Delegation to ensure that public power interests are well-represented in Washington.

As Town Manager Noble emphasized, "Member cities should not underestimate the power of a strong grassroots initiative in building political strength."

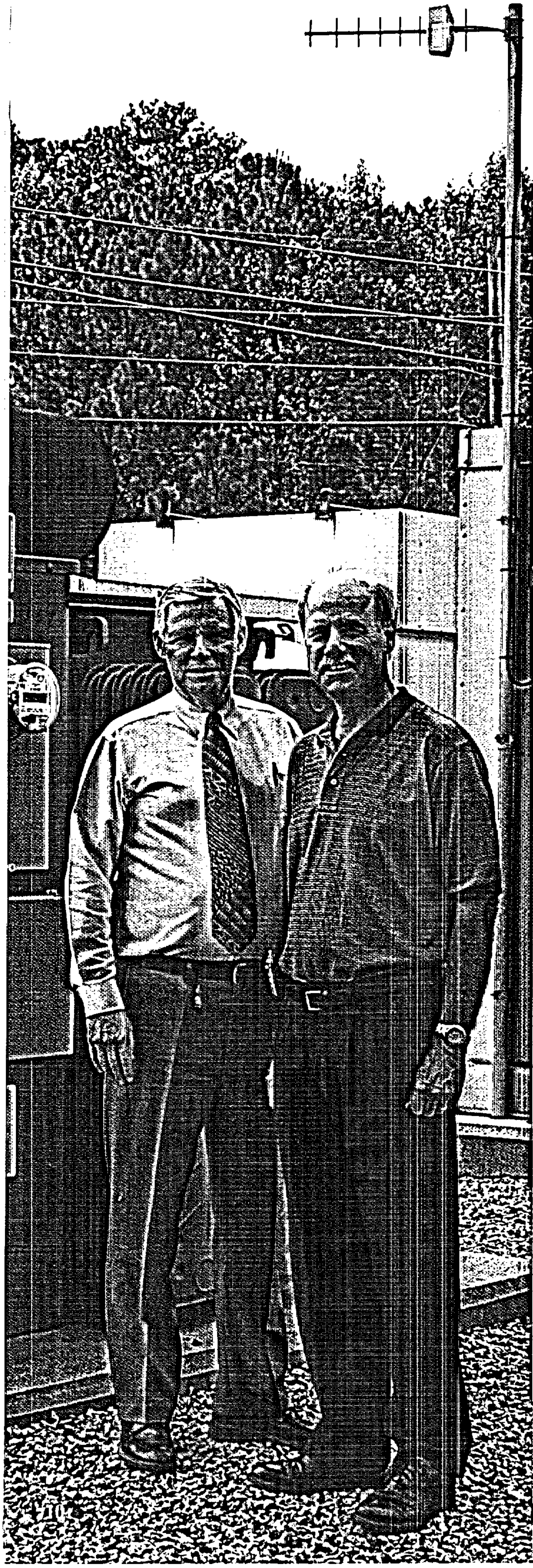


Roland Clark, City Council member,
Mayor Pro-tem David Smoot and
Mayor Donald Morris



C04

# City of Wilson



Keeping industrial customers competitive is a primary goal for Wilson Energy. With today's world economy, industrial managers are under increasing pressure to lower costs in the United States. At Wilson Energy, large business and industrial customers enjoy individual attention. They pride themselves in knowing their local industries personally and doing all that they can to give them reliable service and competitive rates.

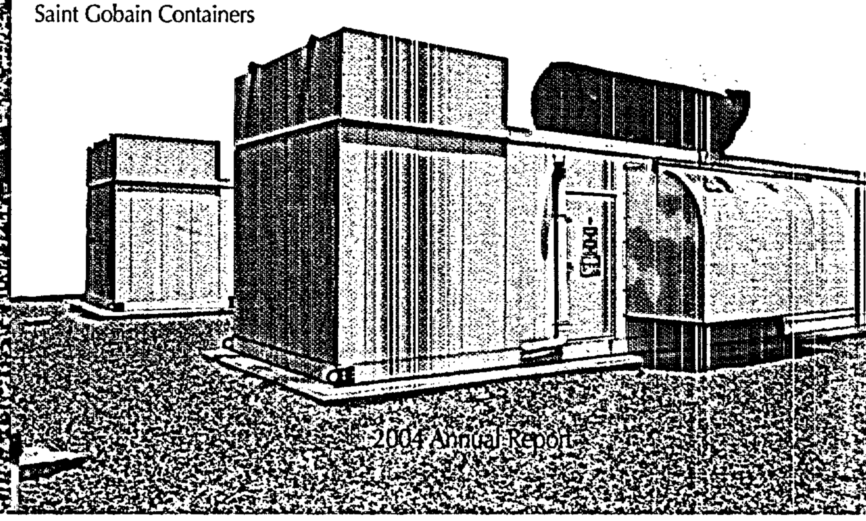
One of Wilson's most effective tools is peak-shaving generation. With the assistance of Wilson Energy, industrial and large commercial managers can use generators to reduce their load during peak demand times. "Generators are one of our most important tools in these days of higher energy costs," said Wilson Director of Public Utilities Fred Horne. "By lowering their peak demand, our industrial customers are able to improve their electrical costs significantly."

Using generators and other load-management programs reduces demand cost for Wilson Energy by reducing its system load during Progress Energy's system peak hour, on which Wilson Energy pays its demand charge. The reduced costs are then passed on to participating customers through coincidental peak rates or load management credits. The generators typically have a three-to four-year payback period.

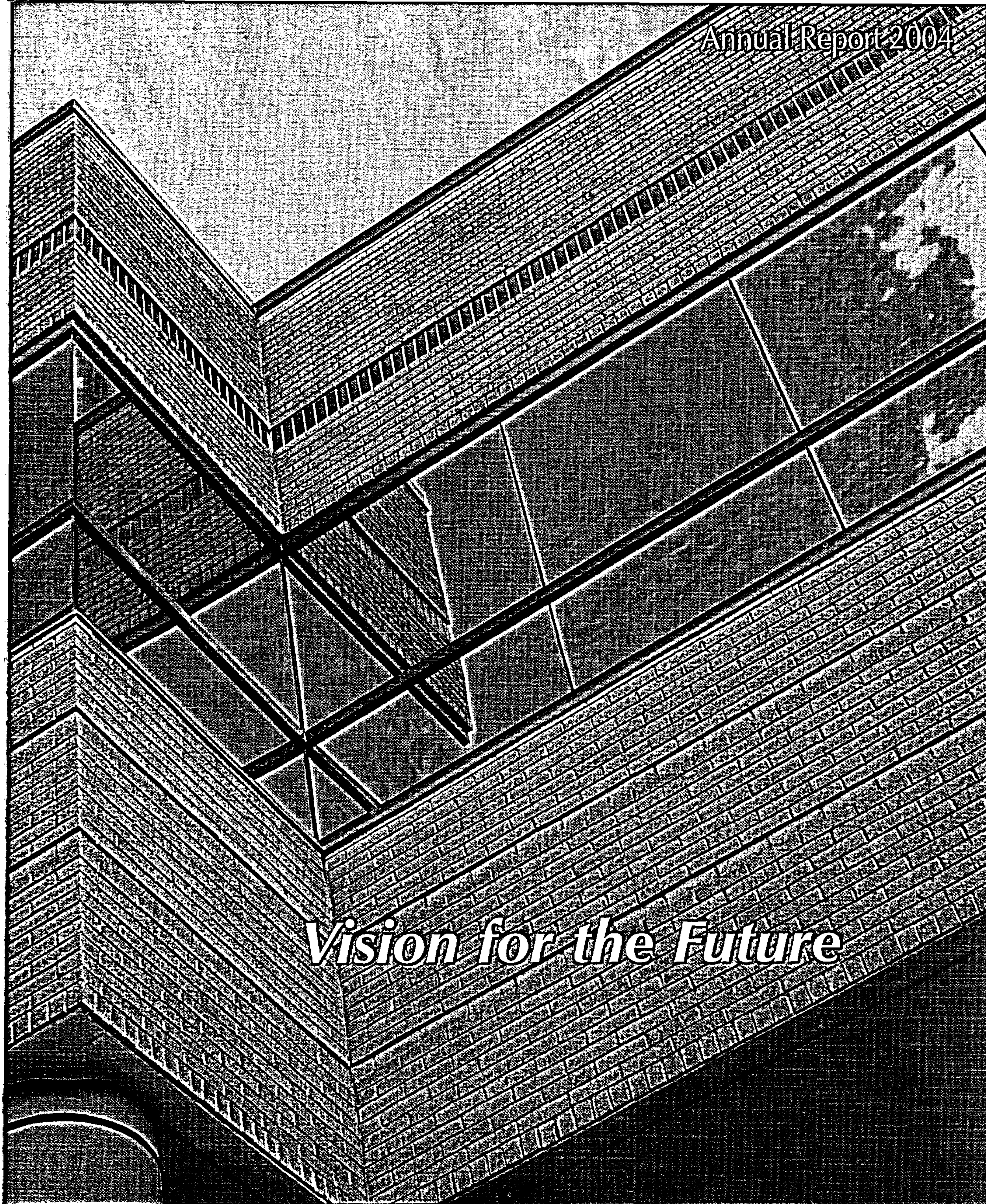
Currently, Wilson Energy has 29 customer-owned generators totaling 34 MW as well as 16 City-owned generators totaling 16 MW. Wilson Energy uses its SCADA system to turn on the generators remotely and performs courtesy inspections of all generators after every load management period. It also responds to any of these generators if there's an operational problem, in an effort to have them all running during the system peak hour.

One company benefiting from the program is Wilson's Saint Gobain Containers, a manufacturer of glass beverage bottles. Saint Gobain has five generators on-site to manage peak-load demand and reduce power costs. Plant Manager Ross Houser was pleased with the support provided to his company by Wilson Energy in installing and implementing the program. "I was pleased with the level of cooperation," he commented. "Installation was accomplished with a minimum of down-time."

Fred Horne, Director of Public Utilities
and Ross Houser, Plant Manager,
Saint Gobain Containers



# Annual Report 2004



# Vision for the Future

North Carolina Municipal Power Agency Number 1 / North Carolina Eastern Municipal Power Agency ELECTRICITIES

# TABLE OF CONTENTS



*The audit reports of and financial information regarding each North Carolina Municipal Power Agency are included in this report. Each Power Agency is a separate and distinct legal entity and the inclusion of such information regarding both entities should not be construed to indicate any relationship between the two.*

# *City of* Gastonia

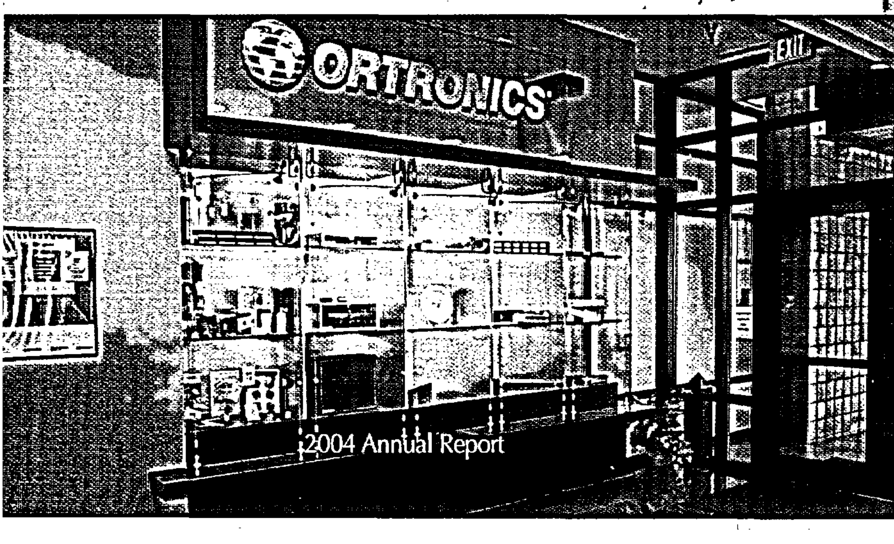
A recent Comprehensive Economic Development Strategy (CEDS) for Gaston and Cleveland Counties gave Gastonia leaders the opportunity to actively participate in reshaping their economy for the 21st century. In addition to the restructuring of growth in all sectors of Gastonia's development: residential, commercial and industrial, the CEDS also stirred additional interest in and momentum for revitalizing the downtown area. Boosted by local government investment in renovated and expanded office buildings, an increasing number of retailers and other small businesses are further enlivening the downtown.

The city and surrounding areas of the county had lost a large number of textile industry jobs, but a wide diversity of new industry had located or expanded in the community. With close proximity to the rapidly growing Charlotte area and its busy international airport, attention was given to attracting a greater share of regional growth through careful planning and progressive leadership. One key element in the revitalization effort was the establishment of Gastonia Technology Park.

Gastonia Technology Park is a showcase for both the City of Gastonia and Gaston County, demonstrating the community's proactive orientation to economic development. Even before the completion of the CEDS strategy, the Gaston County Economic Development Commission could see that the continuing losses of textile jobs required a first-class effort to attract more technology-oriented companies and jobs with staying power. Thus the site for Gastonia Technology Park was selected just south of Gaston College, a highly-rated community college, that offers a wide variety of technology education programs and training adaptable to any businesses' needs. Heavy electrical and fiber optic service lines were installed underground and beautiful landscaping, winding roads, sidewalks and seating areas create a pedestrian-friendly, aesthetically pleasing campus-like environment.

Ortronics located a major 155,000 square-foot state-of-the-art manufacturing plant there, making a wide range of electrical components and connectors. More than a dozen other sites are available within the park's 350 acres, conveniently located along U.S. 321, which connects I-85 in Gastonia with I-40 in nearby Hickory.

Walter "Dub" Dickson, ElectriCities
Board of Directors and
Mayor Jennifer Stultz



# North Carolina Municipal Power Agency Number 1

Market Square Station, Albemarle

Jack F.Neel
*NCMPA1 Chairman*
Albemarle

"As a result of these cost savings measures and a general positive outlook for the future, two credit rating agencies upgraded NCMPA1's credit rating in December 2004, which leads to lower interest rates paid on new debt issued."

# Letter to the Stakeholders

*From the Chairman*

North Carolina Municipal Power Agency Number 1 (NCMPA1) experienced an outstanding year in 2004. NCMPA1 staff assembled a resource team that met throughout the year to evaluate solutions for power supply services, including purchases of peaking capacity, reserves, load-following services and hourly desk functions. The team ultimately recommended a comprehensive power supply proposal to the ElectriCities Board of Directors (Board). The Board approved contracts with Duke Power, Southern Company, Dynergy, Progress Ventures (a subsidiary of Progress Energy Carolinas) and ACES, part of the comprehensive program that delivered a five-year net present value savings of over $30 million. This arrangement enables NCMPA1 staff to conduct all day-ahead, short, mid and long-term marketing. The telemetry system, continuously operated and maintained by NCMPA1 staff, achieved over 99 percent reliability to support NCMPA1's dynamic scheduling of power supply resources.

In addition to the savings realized from the new power supply arrangement, savings were also realized in 2004 from the 2003 Board action to increase transaction capacity from 400MW to 832MW, resulting in an elimination of reserve capacity and energy purchases, together saving NCMPA1 approximately $6.5 million for the year. Additional savings are expected from refundings approved by the Board. As a result of these cost savings measures and a general positive outlook for the future, two credit rating agencies upgraded NCMPA1's credit rating in December 2004, which leads to lower interest rates paid on new debt issued.

Operations in NCMPA1-owned generation were outstanding in 2004. Catawba Unit 2 completed a record continuous run of 531 days, the longest ever for any nuclear unit on the Duke Power system. And, economic development and electric load growth in NCMPA1 cities continues to be a priority. In 2004, an innovative new solution in industrial park development was created with the Prime Power Park™. The Prime Power Park™ will feature a redundant power supply system, using backup generation to supply power to park tenants in an emergency. The first Prime Power Park™ will be located in the City of Albemarle. The industrial park is designed specifically to attract new industrial customers with mission-critical power needs. The city signed onto the project this year and construction began at the site. Target marketing plans were completed for ten NCMPA1 cities. Economic development websites have been created for almost all of the NCMPA1 cities.

While many NCMPA1 cities celebrated economic development successes this year as the Agency added over $90 million in investment, 812 new jobs and 8MW of new electric load, a few key announcements included ZF Lemforder in Newton, Getrag Gears in Maiden and Kao Specialists in High Point.

Distributed generation continues to provide reserves that enable NCMPA1 to avoid reserve capacity purchases, leading to a savings of almost $700,000 in 2004. All 10 units operated at near 100 percent reliability in 2004. Additionally, NCMPA1 placed under contract an additional 25 MW of distributed generation, which will be coordinated through the NCMPA1 control center. This year, NCMPA1 implemented new "economic dispatch" principles for distributed generation, providing NCMPA1 with more direct control of the units to increase the benefits of distributed generation to the Agency's power supply program. The new policy will allow a reduction in the operating hours for distributed generation on-peak periods, reduce off-system reserve purchases and reduce diesel fuel consumption by distributed generation owners.

Electric load management strategy in 2004 focused on forecasting accuracy, which reduces the number of load management control hours. As a result of load management, $6.5 million in savings was passed along to customers of NCMPA1's member cities. Also, NCMPA1 operated load management an average of six hours per month, which was 40 percent less than the hours operated in 2003.

This year resulted in success worthy of celebrating, yet more importantly, several measures implemented, such as the load management principles and power supply contracts, will poise NCMPA1 for future growth and efficient operations. As we look to the future with a vision for our cities and the life our citizens enjoy, let's enjoy the accomplishments and cooperation and work together for continued success.

**Jay C. Stowe**
*Secretary-Treasurer*
Shelby

**John T. Walser, Jr.**
*Vice Chairman*
Lexington

**Jack F. Neel**
*Chairman*
Albemarle

## 2004 NCMPA1 Board of Commissioners

*Alternate commissioners' names appear in italics*

**Albemarle**
Mr. Raymond I. Allen
*Mr. Jack F. Neel*

**Bostic**
Commisioner Vacant
*First Alternate Vacant*

**Cherryville**
Mr. Ron Hovis
*Ms. Gert K. Fisher*

**Cornelius**
Mayor Gary T. Knox
*Mr. James R. Bensman*

**Drexel**
Mr. Matt Settlemyer
*First Alternate Vacant*

**Gastonia**
Mr. Franz F. Holscher
*Mr. W. F. "Butch" Adams*

**Granite Falls**
Ms. Linda K. Story
*Dr. Caryl B. Burns*

**High Point**
Mayor Rebecca R. Smothers
*Mr. Stribling P. Boynton*

**Huntersville**
Mr. Jeff Pugliese
*Mr. Jerry E. Cox*

**Landis**
Mr. Bobby O. Wood
*First Alternate Vacant*

**Lexington**
Mayor Richard L. Thomas
*Mr. John T. Walser, Jr.*

**Lincolnton**
Mr. Stephen H. Peeler
*Mr. Jeff B. Emory*

**Maiden**
Mr. Kevin C. Sanders
*Mr. Todd Clark*

**Monroe**
Mr. Donald D. Mitchell
*Mr. Robert J. Smith*

**Morganton**
Mr. Dan Brown
*Ms. Sally W. Sandy*

**Newton**
Mr. Edward F. Burchins
*Mr. Martin D. Wilson*

**Pineville**
Mayor George Fowler
*Ms. Mary Ann Creech*

**Shelby**
Mr. Kevin K. Allen
*Mr. Jay C. Stowe*

**Statesville**
Mr. Arthur E. Peterson
*Mr. Herbert "Jim" Lawton*

# NCMPA1 ELECTRIC SYSTEM PARTICIPANTS

| City | Year | Revenues | Customers | % Ownership |
|---|---|---|---|---|
| Albemarle | 2004 | $24,906,718 | 11,496 | 7.604% |
| | 2003 | $24,949,517 | | |
| Bostic | 2004 | not available | 185 | 0.087% |
| | 2003 | $303,982 | | |
| Cherryville | 2004 | $4,731,803 | 2,926 | 1.579% |
| | 2003 | $4,055,417 | | |
| Cornelius | 2004 | $4,071,292 | 2,309 | 0.362% |
| | 2003 | $3,187,456 | | |
| Drexel | 2004 | $1,578,202 | 1,183 | 0.507% |
| | 2003 | $1,804,394 | | |
| Gastonia | 2004 | $54,741,137 | 25,200 | 17.121% |
| | 2003 | $54,499,868 | | |
| Granite Falls | 2004 | $4,029,175 | 2,354 | 0.912% |
| | 2003 | $4,077,630 | | |
| High Point | 2004 | $90,431,510 | 37,207 | 18.960% |
| | 2003 | $85,029,325 | | |
| Huntersville | 2004 | $6,008,172 | 3,531 | 0.623% |
| | 2003 | $5,719,111 | | |
| Landis | 2004 | $3,769,437 | 2,607 | 1.130% |
| | 2003 | $4,169,012 | | |
| Lexington | 2004 | $42,413,871 | 18,224 | 12.934% |
| | 2003 | $43,471,149 | | |
| Lincolnton | 2004 | $5,663,797 | 2,819 | 1.608% |
| | 2003 | $5,632,490 | | |
| Maiden | 2004 | $4,604,873 | 1,034 | 1.289% |
| | 2003 | $5,014,582 | | |
| Monroe | 2004 | $33,438,080 | 9,741 | 10.038% |
| | 2003 | $33,925,723 | | |
| Morganton | 2004 | $21,281,479 | 7,898 | 6.735% |
| | 2003 | $22,214,145 | | |
| Newton | 2004 | $8,742,343 | 4,266 | 2.115% |
| | 2003 | $8,561,552 | | |
| Pineville | 2004 | $9,019,723 | 2,452 | 0.536% |
| | 2003 | $9,089,225 | | |
| Shelby | 2004 | $14,470,116 | 7,990 | 5.996% |
| | 2003 | $14,632,334 | | |
| Statesville | 2004 | $31,905,469 | 12,659 | 9.864% |
| | 2003 | $32,672,918 | | |

## Plant Information

| | Capacity Factor * | Availability Factor * |
|---|---|---|
| Catawba Unit 1 | 97.9 | 98.3 |
| 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 Energy to the Nuclear Regulatory Commission in the units' December 2004 Operating Data Report.*

***Catawba Unit 1*** began a refueling outage on November 8, 2003 that ended on December 31. The 54 day refueling outage was longer than recent outages due to the Rewind project on the Main Generator. 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*** is scheduled to begin a refueling outage on March 1, 2005 that is scheduled to end on April 21. The unit completed a continuous run of 506 days.

## Catawba and McGuire 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:

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

## Supplemental and Transmission Agreements

NCMPA1 continues to purchase power through bilateral agreements with other utilities and merchant generators for its energy and capacity requirements above its Catawba Project Entitlements. In 2004, these additional power needs came from the following suppliers:

**NCMPA1** has a five-year agreement with Georgia Power Company purchasing 125 MW that began on January 1, 2001.

**NCMPA1** purchased 50 MW of capacity from Dynegy Power Marketing, Inc. from their Rockingham County North Carolina Units 1 through 4.

**NCMPA1** has the right to schedule and receive 60 MW of power from the Southeastern Power Administration.

**NCMPA1's** two-year agreement with Southern Company expired in 2004. Southern provided resource management services including scheduling energy deliveries from NCMPA1's resources to meet NCMPA1's native load requirements and surplus sales commitments.

In 2004, NCMPA1 entered into an Instantaneous Capacity and Energy Services Agreement for 75 MW and a Backstand Capacity and Energy Agreement for up to 432 MW with Duke Power for the years 2005 through 2007. NCMPA1 also entered into a marketing services agreement with ACES Power Marketing for 2005. Beginning on January 1, 2005, the combination of these agreements enables NCMPA1 to perform all intra-day energy services through ACES while conducting its day-ahead, short-, mid- and long-term marketing through internal resources.

NCMPA1 purchases transmission for its native load requirements from Duke Electric Transmission in accordance with Duke's Open Access Transmission Tariff. All the required agreements have been filed and approved by the Federal Energy Regulatory Commission (FERC).

## Distributed Generation

NCMPA1 owns 10 1,825 kW generators located at city delivery points. These units, totaling 18.25 MW, were installed in 2002 and are operated on short notice during periods of high demand and high market prices. Also under remote control operation are city generators totaling 35 MW. This combination of over 50 MW of remote operation, fast start units provides great operational flexibility for NCMPA1's power supply program.

NCMPA1 has been successful in placing under contract an additional 25 MW of generation owned by cities and retail customers for local operations under NCMPA1's power supply program. These operations are coordinated through NCMPA1's control center, maintaining availability during times of peak demand and high market prices. NCMPA1 will continue to evaluate additional distributed generation opportunities to improve power supply flexibility and reliability.

### Load Management

Almost $6.5 million in savings were passed on to customers as a result of NCMPA1's load management operations. The operation of various demand-side management programs results in a total peak reduction of over 70 MW each month. The load management strategy this year focused on forecasting accuracy, effectively reducing the number of load management control hours. NCMPA1 operated load management an average of six hours per month, which is 40 percent less than 2003.

### Retail Billing Services

NCMPA1 continues to provide retail billing services to the cities through its Customer Billing System and database. This system allows cities to offer innovative retail rates that could not be accommodated by their internal billing systems. City staff members utilize customer usage data, stored in the database and accessible through a secure extranet site, in making cost saving operational recommendations to customers.

### Wholesale Rates

NCMPA1 had a one percent wholesale rate increase in 2004 that also included revenue-neutral rate structure changes to more accurately reflect its power supply costs.

### Security

Following the 2001 terrorist attacks on the World Trade Center and Pentagon, the nation's nuclear plants came under scrutiny as potential targets. As a result, nuclear power plants upgraded security measures. Under the contractual agreement with both NCMPA1 and NCEMPA, all issues of security are handled by Duke and PEC. Both Duke and PEC coordinate closely with federal, state and local authorities and continue to take appropriate steps to ensure safety and security at all the nuclear facilities in which NCMPA1 and NCEMPA have ownership.

### Economic Development

The western North Carolina cities continue their success with industry recruitment and expansion of their existing industries. In 2004, NCMPA1 members added 812 new jobs to their communities with investments totaling $92,007,880. New load added to the Agency totaled more than 8 MW. Staff continues their efforts with the North Carolina Department of Commerce, local developers and regional partnerships to further the strategic load growth efforts in our communities.

Emphasis was placed on Target Marketing Plans for the cities. The main focus of these plans is to provide strategies, industry targets and specific action steps necessary for each community to successfully pursue the recruitment of new businesses and industries. The elements of the plan include: Economic and Demographic Profile; Economic Development Preparedness Assessment; Target Market Analysis with Recommended Industry Targets; and a Marketing Plan. Plans have been completed and work continues with the implementation process. City officials and ElectriCities staff will be working with industry sectors identified as well as working with the Whittaker Group to focus recruitment efforts on companies identified as having plans to expand or relocate within 12-18 months.

There were several successes for new industry recruitments. Z. F. Lemforder will be locating in Newton, resulting in 200 new jobs and $40 million in investment. Getrag Gears will be expanding in Maiden with 200 jobs and $80 million in investment. Other success stories include Goodrich in Monroe with 300 jobs and $11 million investment and Globalec Industries in High Point with 60 jobs and $1 million investment.

Advertising for the year was focused on the following segments: Automotive; Pharmaceutical/Medical Instruments; Electronics; Biotechnology; Rubber; Plastics; and Fabricated Metals. Approximately 269 inquiries were made which resulted in numerous site visits within the cities and towns.

Marketing and promotion exhibits were submitted to the Southern Economic Development Council (SEDC) for their yearly awards. The Lake Norman Regional Economic Development Commission (Cornelius and Huntersville) advertising campaign received an award of merit.

#### *Marketing and Customer Retention Program*

The participants of NCMPA1 continue to focus on the retention of large industrial and commercial accounts as well as other key accounts in their communities. Agency participants recognize the important roles these key accounts play in their cities and towns. NCMPA1 staff and members received key account training through ElectriCities. ElectriCities became the first APPA member to offer APPA's Key Accounts Certificate Program when it presented the course in August 2003 in Boone, North Carolina. A second class was held in May 2004 in Wilmington. The fast track program consists of three courses, along with an oral and a written exam. Class participants also were required to file a key accounts business plan and a customer marketing plan to complete the requirements for certification.

The Agency members continue to call upon the expertise of the Agency's Key Accounts Managers to better serve their largest end-users. A formal key account plan is being developed for each of the 19 agency members. The ultimate goal of this effort is to help these key community businesses maintain a high level of efficiency and prosper within the Agency members' distribution systems.

The customer retention program includes innovative rate structures, customer education and energy solutions provided through our Energy Solutions Partner (ESP) program. For example, new on-peak and off-peak rates and customer generation rate riders allow customers to reduce their demand for energy during periods of high power costs. Commercial and industrial customers have access to day-long seminars on subjects ranging from energy management and sub-metering to power restoration. The Agency's ESP program has formed partnerships with nationally known companies to help provide valuable energy solutions to key customers. Examples include PowerSecure's Interactive Distributed Generation system and Carrier Corporation's HVAC solutions. The ESP program sold over $5.2 million in products and services during 2004.

Also in 2004, NCMPA1 took an active role in working with the healthcare industry. Several hospitals and long-term care facilities are located throughout our members' communities and they play a vital role in the welfare of the communities. In an effort to work with this group of customers, NCMPA1 held a workshop on back-up generation at healthcare facilities, which was promoted jointly by NCMPA1 and the North Carolina Hospital Association.

Last year, at the request of several member cities, a new team of ElectriCities employees was assembled to develop programs and services to help cities address the needs of residential customers. The team, named HEAT (the Home Energy Assistance Team) developed a comprehensive array of programs and services to enable residential customers to save money on electric bills and conserve energy.

Some of the initiatives resulting from HEAT's efforts were: energy education programs, including Understanding Energy Use Workshops; communication programs such as the weatherization video distributed in December; new Energy Auditor Training; and customized Customer Service Training.

### Huntersville/Cornelius

The merger of Huntersville and Cornelius electric operations in 1997 continues to show reduced operating costs, exceptional customer service and value for customers of the towns. Other achievements in 2004 include the department's receipt of the highest safety award given by the NC Association of Municipal Electric Systems for working in excess of 90,000 hours without an accident or injury.

Both towns renewed their contract with ElectriCities to operate and maintain their electric systems. Reduced operating costs and economies of scale from load growth have enabled both towns to maintain electric rates at the same level for the past five years. As both towns continue to grow and regional economic development is emphasized, operating costs continue to decline.

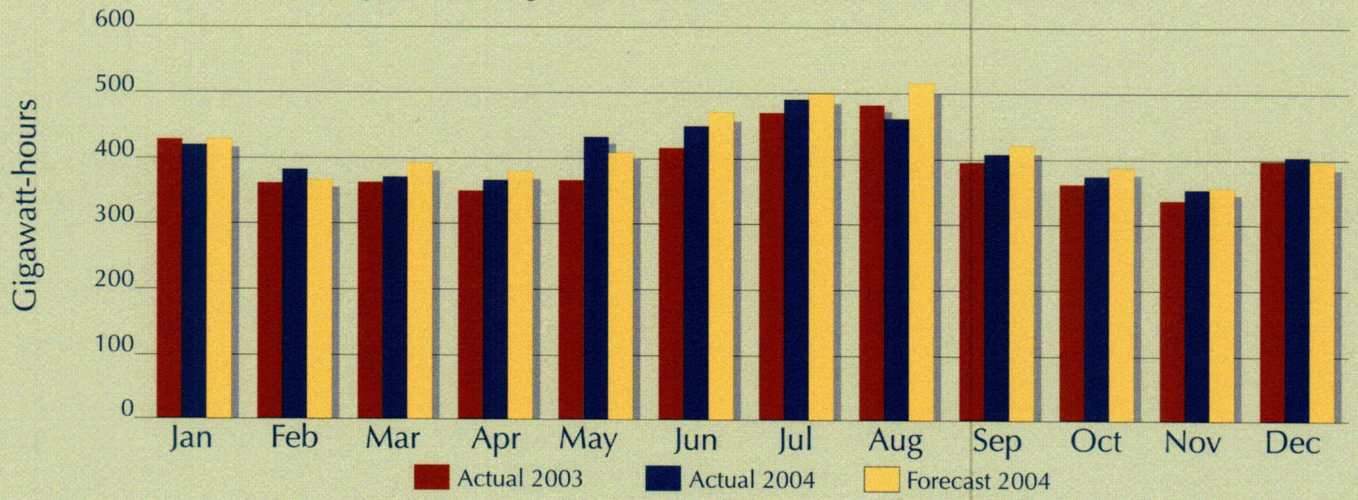
Providing safe, responsive and value-added customer service is emphasized in daily operations. A new meter reading system, including expanded automated reading, was installed for the towns. Both towns are transitioning to a new computer and billing system that will include improvements in bill format, information and more payment options.

The Huntersville/Cornelius merger has been successful and shows that regionalization of electric systems is possible and economical for customers and towns.

# NCMPA1 OPERATIONAL HIGHLIGHTS

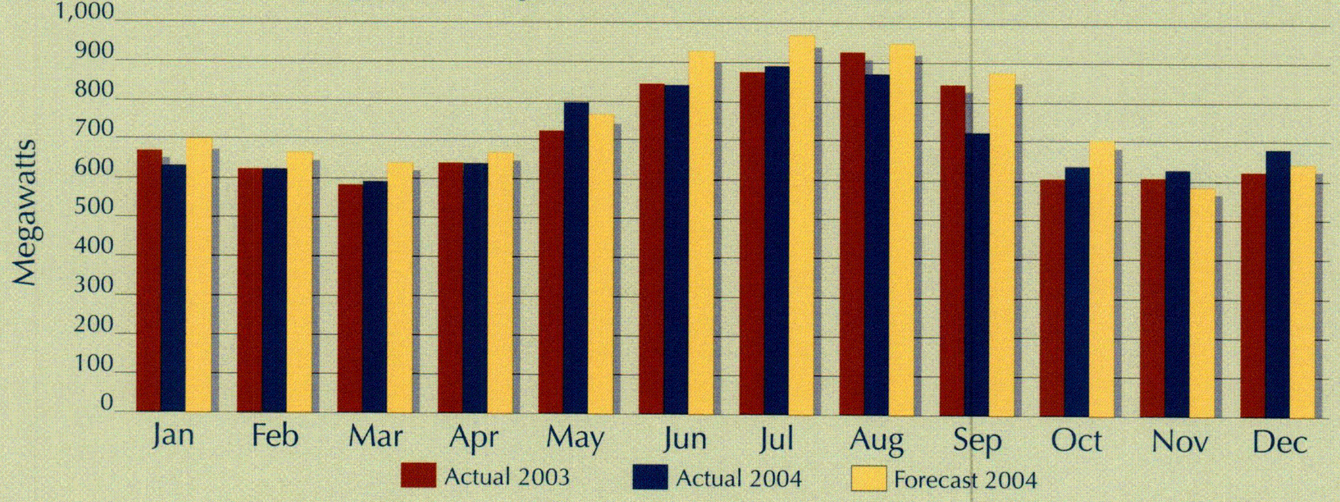
## NCMPA1 Participant Energy Usage

(Billing Point Including SEPA; Forecast Year 2004 is from the 2003 Load Forecast)

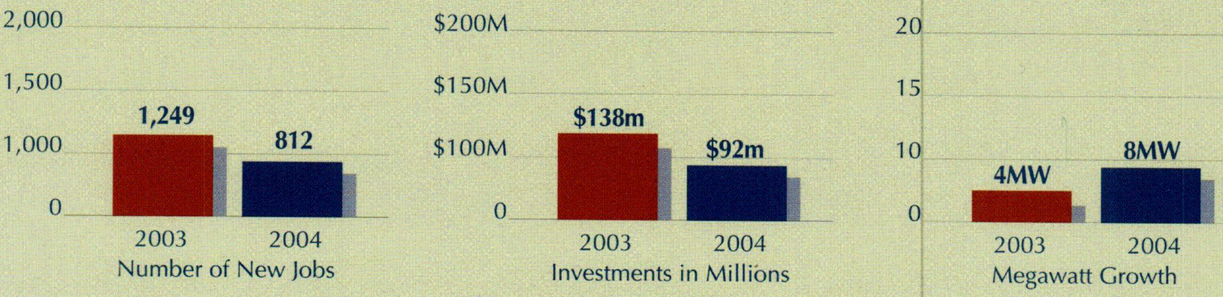



## NCMPA1 Participant OP Demand

(Billing Point Including SEPA; Forecast Year 2004 is from the 2003 Load Forecast)




## NCMPA1 Economic Development



## Investment Portfolio Statistics

**Earnings***

| | Income | Rate of return |
|---|---|---|
| 2004 | $36,136,000 | 4.69% |
| 2003 | $36,105,000 | 4.84% |

**Market Value as of 12/31***

| | Value | Average maturity |
|---|---|---|
| 2004 | $869,416,000 | 5.7 years |
| 2003 | $844,695,000 | 5.1 years |

**Transactions**

| | Number | Amount |
|---|---|---|
| 2004 | 514 | $5,839,222,000 |
| 2003 | 632 | $7,769,255,000 |

## Debt Outstanding

**Debt Outstanding 12/31**

| | Balance | Weighted Average Interest Cost |
|---|---|---|
| **Fixed Rate Bonds** | | |
| 2004 | $1,835,965,000 | 5.52% |
| 2003 | $1,877,870,000 | 5.46% |
| **Variable-Rate Securities** | | |
| 2004 | $149,700,000 | 1.42% |
| 2003 | $149,700,000 | 1.34% |

## NCMPA1 Bond Reconciliation

| | |
|---|---|
| **Bonds Outstanding** 12/31/03 | $ 2,027,570,000 |
| **Matured** 1/1/2004 | 41,905,000 |
| **Bonds Outstanding** 12/31/04 | $ 1,985,665,000 |

## NCMPA1 Bonds Outstanding

| Series | Par Amount |
|---|---|
| Series 1992 | $ 364,860,000 |
| Series 1993 | $ 150,515,000 |
| Series 1995A | $ 79,440,000 |
| Series 1997A | $ 97,775,000 |
| Series 1998A | $ 127,645,000 |
| Series 1999A | $ 83,340,000 |
| Series 1999B | $ 200,600,000 |
| Series 2003A | $ 713,310,000 |
| Series 2003B | $ 18,480,000 |
| Series 2003C | $ 149,700,000 |

* For earnings and market value, amounts include income from and market value of securities held in the decommissioning trust.

# NCMPA1 INDEPENDENT AUDITORS' REPORT

The Board of Directors
North Carolina Municipal Power Agency Number 1
Raleigh, North Carolina

We have audited the accompanying balance sheets of North Carolina Municipal Power Agency Number 1 as of December 31, 2004 and 2003, and the related statements of revenues and expenses and changes in fund equity, and cash flows for the years then ended. 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provided 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 Municipal Power Agency Number 1 as of December 31, 2004 and 2003, and the changes in financial position and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

The Management's Discussion and Analysis section listed in the table of contents is not a required part of the financial statements but is supplementary information required by the Governmental Accounting Standards Board. 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 this information and express no opinion thereon.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The other financial information as listed in the table of contents as of and for the years ended December 31, 2004 and 2003 is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Cherry, Bekaert & Holland, L.L.P.
Raleigh, North Carolina
April 11, 2005

## Management's Discussion and Analysis (MD&A)

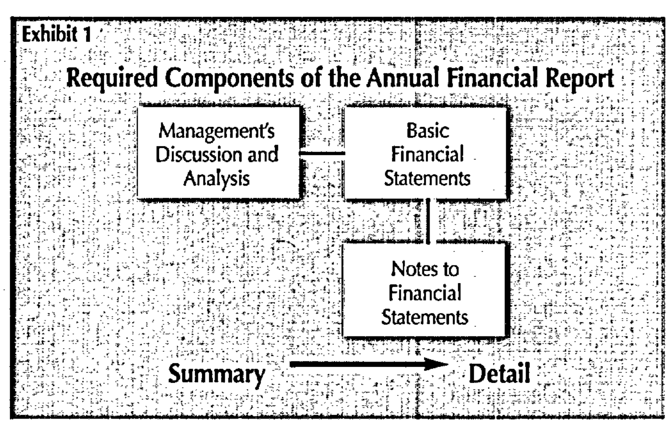
As management of North Carolina Municipal Power Agency Number 1 (the Agency), we offer this narrative overview and analysis of the financial activities of the Agency for the years ended December 31, 2004 and 2003. We encourage you to read this information in conjunction with additional information furnished in the Agency's audited financial statements that follow this narrative.

### Financial Highlights

- The Agency's basic financial statements consist of a single electric enterprise fund.
- At year-end 2004 and 2003, the Agency's assets exceeded its liabilities by $7,400,000 (fund equity).
- The Agency's total fund equity remained unchanged during 2004 and 2003 due to the use of $7,915,000 and $33,293,000, respectively, of Rate Stabilization Funds to meet a portion of operating expenses.
- Year-end 2004 and 2003 unrestricted fund equity was $75,169,000 and $125,207,000, respectively, after decreasing $50,038,000 and $1,506,000, respectively.
- The Agency's total debt decreased $41,905,000 and $125,358,000 during 2004 and 2003, respectively.
  - Decreased $41,905,000 and $64,323,000 due to principal paid January 1, 2004 and 2003, respectively, in accordance with debt service schedules.
  - Decreased $61,035,000 in 2003 due to equity contributions to facilitate the debt refunding issue.
- In March and April 2003 the Agency refinanced some of its existing debt to take advantage of historically low interest rates.
  - In March 2003, the Agency issued $773,445,000 of Series 2003A and B Bonds to refund $802,460,000 of previously issued bonds. Net present value savings realized were $61,748,000 with estimated annual debt service reductions of approximately $6,000,000 per year through 2019.
  - In April 2003, the Agency issued $149,700,000 of Series 2003C Bonds to refund $181,720,000 of previously issued bonds. The 2003C issue is variable rate debt. To estimate the present value savings and related debt services schedules, the Agency assumed a 3.5% interest rate over the life of the debt. This resulted in a net present value savings of $8,859,000 and estimated annual debt service reductions between $2,056,000 and $3,669,000 per year through 2018.
- As a result of continued improvement in the Agency's financial condition, the rating agencies were invited to visit the Agency and some of its member cities in order to reevaluate their ratings in 2004. In conjunction with the visit and the bond offering in 2003 the bond ratings remained the same or improved as follows:
  - Standard and Poor's – Unchanged at BBB+ (stable) throughout the two year period.
  - Moody's – From Baa1 (stable) to Baa1 (positive) in 2003 and from Baa1 (positive) to A3 (stable) in 2004.
  - Fitch – From BBB+ (stable) to BBB+ (positive) in 2003 and from BBB+ (positive) to A- (stable) in 2004.
- The Agency increased rates to Participants by 1.0% and 2.0% effective July 1, 2004 and 2003, respectively, in accordance with the Agency's Rate Increase Relief Plan.
- In 2003, the Agency received $11,200,000 from the counterparty to the swap for amending the agreement to allow the counterparty the one-time opportunity to terminate the swap on January 1, 2005 with no termination fee.

### Overview of the Financial Statements

This MD&A serves as an introduction to the Agency's basic financial statements and notes to the financial statements (see Exhibit 1). In addition to the basic financial statements, this report contains other supplemental information designed to enhance your understanding of the financial condition of the Agency.



## Basic Financial Statements

The Agency is a special purpose government that accounts for its activities as a business type entity. The first statements of the basic financial statements are for the Agency's single proprietary fund that focuses on the business activities of the electric enterprise. The statements are designed to provide a broad overview of the Agency's finances, operations and cash flows, similar in format to private sector business statements, and provide short and long-term information about the Agency's financial status. The statements report fund equity and how it has changed during the period. Fund equity is the difference between total assets and total liabilities. Analyzing the various components of fund equity is one way to gauge the Agency's financial condition.

The second section of the basic financial statements is the notes that explain in more detail some of the data contained in the basic financial statements. The notes provide additional information that is essential to a full understanding of the data provided in the fund financial statements. The notes are on pages 32 to 44 of this report.

After the notes, supplemental information is provided to show how the Agency's rates recovered its expenses as defined by the Bond Resolution, to show the Agency's performance against budget and to show activities in the special funds established by the Bond Resolution. Supplemental information can be found on pages 45 to 47 of this report.

## Financial Analysis

The electric enterprise fund financial statements for the years ended December 31, 2004 and 2003 are presented in accordance the Governmental Accounting Standards Board (GASB) Statement 34.

The various components of fund equity may serve over time as a useful indicator of the Agency's financial condition. The assets of the Agency exceeded liabilities by $7,400,000 at December 31, 2004, 2003 and 2002. The Agency's net assets remained unchanged during 2004 and 2003 due to the use of $7,915,000 and $33,293,000, respectively, of Rate Stabilization Funds to cover operating expenses in accordance with the rate setting plan.

The deficit portion of fund equity of $(183,043,000), $(205,521,000) and $(299,407,000) at December 31, 2004, 2003 and 2002, respectively, reflects the Agency's investments in capital assets (e.g. land, buildings, generation facilities, nuclear fuel and equipment), less any related debt still outstanding that was issued to acquire those items. The deficit occurs because depreciation is expensed on a straight line basis over the life of the plant while debt repayment is structured similar to a home mortgage where early debt payments include more interest than principal and later payments include more principal than interest. This deficit was reduced during 2004 and 2003 due to the payment of principal debt service on January 1 of each year and the payment of capital additions from current operating funds. In 2003 it was also reduced due to the equity contributions to facilitate the refunding issue. Both years' reductions were net of depreciation expense.

The Agency uses these capital assets to provide power to its Participants. Consequently, these assets are not available for

**Exhibit 2** — **Fund Equity** ($000s)

| | December 31, 2004 | 2003 | 2002 |
|---|---|---|---|
| Assets | | | |
| Capital assets | $ 918,209 | $ 924,415 | $ 864,897 |
| Current and other assets | 1,627,868 | 1,642,426 | 1,716,121 |
| Total assets | 2,546,077 | 2,571,841 | 2,581,018 |
| Liabilities | | | |
| Long-term liabilities outstanding | 2,398,295 | 2,450,929 | 2,425,775 |
| Other liabilities | 140,382 | 113,512 | 147,863 |
| Total liabilities | 2,538,677 | 2,564,441 | 2,573,638 |
| Fund Equity | | | |
| Invested in capital assets, net of related debt (deficit) | (183,043) | (205,521) | (299,407) |
| Restricted for debt service | 115,274 | 87,714 | 151,143 |
| Restricted for decommissioning | | | 28,951 |
| Unrestricted | 75,169 | 125,207 | 126,713 |
| Total fund equity | $ 7,400 | $ 7,400 | $ 7,400 |

future spending. Although the Agency's investments in capital assets are reported net of the outstanding related debt, the resources needed to repay that debt will be provided through rates and certain reserve funds since the capital assets cannot be used to liquidate the liabilities.

An additional portion of the Agency's fund equity of $115,274,000, $87,714,000 and $151,143,000 as of December 31, 2004, 2003 and 2002, respectively, represents resources that are restricted for the payment of debt service.

An additional portion of the Agency's fund equity $-0-, $-0- and $28,951,000 at December 31, 2004, 2003 and 2002, respectively, represents resources that are restricted for the payment of the Agency's asset retirement obligation (decommissioning of the nuclear units). The adoption of the Statement of Financial Accounting Standard (SFAS) No. 143, "Accounting for Asset Retirement Obligations" resulted in deficit amounts in 2004 and 2003 and these deficits have been reclassified to unrestricted net assets. The recognition of the asset retirement obligation is on the straight-line basis over the life of the plant while funding of the decommissioning trust takes into account the interest earnings on the moneys deposited into the fund.

The remaining balance of $75,169,000, $125,207,000, and $126,000,000 as of December 31, 2004, 2003 and 2002, respectively, is unrestricted fund equity.

The aspects of the Agency's financial operations that most influenced total unrestricted net equity is:

- Other revenues increased as a result of the benefit received from modifying the original swap agreement to provide the counter party with a one-time option to terminate the agreement of January 1, 2005.
- Revenues increased as a result of a rate increase instituted each year.
- The Agency balances revenues and expenses through the use of its Rate Stabilization Fund.

## Budgetary Highlights

- No amendments were necessary either year.
- The Agency implemented a 1.0% and 2.0% rate increase effective July 1, 2004 and 2003, respectively.
- The Agency utilized $7,915,000 and $33,293,000 of the Rate Stabilization Fund during the 2004 and 2003, respectively.

**Exhibit 3**

### Changes in Fund Equity
($000s)

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| **Revenues:** | | | |
| Sales of electricity and other operating revenue | $ 364,132 | $ 363,014 | $ 355,230 |
| Nonoperating revenues | 27,957 | (2,837) | 80,912 |
| Total Revenues | 392,089 | 360,177 | 416,142 |
| **Expenses:** | | | |
| Operating expenses | 248,394 | 269,562 | 269,838 |
| Interest on long-term debt | 91,689 | 94,682 | 111,492 |
| Other nonoperating expenses | 52,006 | (4,067) | 34,812 |
| Total Expenses | 392,089 | 360,177 | 416,142 |
| Change in Fund Equity | - | - | - |
| Fund equity January 1 | 7,400 | 7,400 | 7,400 |
| Fund equity December 31 | $ 7,400 | $ 7,400 | $ 7,400 |

## Capital Assets and Debt Administration

### Capital Assets

The Agency's investments in capital assets at December 31, 2004, 2003 and 2002 totaled $918,209,000, $924,415,000 and $864,897,000, respectively (net of accumulated amortization and depreciation). These assets include land, buildings, generation facilities, nuclear fuel and equipment.

Major capital asset transactions during the year include the following:

- Construction work in progress increased $18,786,000 and $14,308,000 in 2004 and 2003, respectively, due to capital additions at the Catawba plant.
- Construction work in progress decreased and electric plant in service increased by $24,296,000 and $14,770,000 in 2004 and 2003, respectively, due to the transfer of completed projects.
- Depreciation expense of $42,985,000 and $81,003,000 for 2004 and 2003, respectively.
- In 2004 and 2003 there were write-offs of $43,942,000 and $18,581,000, respectively, of spent nuclear fuel and the retirement of $8,795,000 and $1,730,000, respectively, of electric plant in service.
- In 2003, electric plant in service (EPIS) increased $97,015,000 and accumulated depreciation increased $41,099,000 due to the asset retirement obligation adjustment January 1, 2003 in accordance with Statement of Financial Accounting Standard No. 143, "Accounting for Asset Retirement Obligations."

**Exhibit 4**

**Capital Assets**
**($000s)**

| Electric Utility Plant, Net | December 31, 2003 | Additions | Transfers | Retirements | December 31, 2004 |
|---|---|---|---|---|---|
| Electric Utility Plant | | | | | |
| Electric Plant in Service | $ 1,539,842 | $ - | $ 23,644 | $ (8,795) | $ 1,554,691 |
| Nuclear Fuel | 139,956 | 17,740 | | (43,942) | 113,754 |
| Total Electric Utility Plant | 1,679,798 | 17,740 | 23,644 | (52,737) | 1,668,445 |
| Accumulated Depreciation and Amortization | | | | | |
| Electric Plant in Service | (706,714) | (20,851) | 652 | 8,795 | (718,118) |
| Nuclear Fuel | (86,608) | (21,836) | | 43,942 | (67,504) |
| Total Accumulated Depreciation and Amortization | (796,322) | (42,689) | 652 | 52,737 | (785,622) |
| Total Depreciable Electric Utility Plant (Net) | 883,476 | (24,949) | 24,296 | - | 882,823 |
| Land and Other Non-Depreciable Assets | | | | | |
| Land | 19,768 | | | | 19,768 |
| Construction Work In Progress | 18,687 | 18,786 | (24,296) | | 13,177 |
| Total Electric Utility Plant (Net) | $ 921,931 | $ (6,163) | $ - | $ - | $ 915,768 |

| | December 31, 2002 | Additions | Transfers | Retirements | December 31, 2003 |
|---|---|---|---|---|---|
| Electric Utility Plant | | | | | |
| Electric Plant in Service | $ 1,430,505 | $ 97,015 | $ 14,060 | $ (1,738) | $ 1,539,842 |
| Nuclear Fuel | 129,407 | 29,130 | | (18,581) | 139,956 |
| Total Electric Utility Plant | 1,559,912 | 126,145 | 14,060 | (20,319) | 1,679,798 |
| Accumulated Depreciation and Amortization | | | | | |
| Electric Plant in Service | (647,035) | (62,127) | 710 | 1,738 | (706,714) |
| Nuclear Fuel | (89,628) | (18,561) | | 18,581 | (89,608) |
| Total Accumulated Depreciation and Amortization | (736,663) | (80,688) | 710 | 20,319 | (796,322) |
| Total Depreciable Electric Utility Plant (Net) | 823,249 | 45,457 | 14,770 | - | 883,476 |
| Land and Other Non-Depreciable Assets | | | | | |
| Land | 19,768 | | | | 19,768 |
| Construction Work In Progress | 19,149 | 14,308 | (14,770) | - | 18,687 |
| Total Electric Utility Plant (Net) | $ 862,166 | $ 59,765 | $ - | $ - | $ 921,931 |

Exhibit 4

**Capital Assets**

**Non-Utility Property and Equipment, Net**

**($000s)**

| | December 31, 2003 | Additions | Transfers | Retirements | December 31, 2004 |
|---|---|---|---|---|---|
| Property and Equipment | $ 4,125 | $ 253 | $ - | $ - | $ 4,378 |
| Accumulated Depreciation | (2,351) | (296) | | | (2,647) |
| Total Depreciable Non-Utility Property and Equipment, Net | 1,774 | (43) | - | - | 1,731 |
| Land | 710 | | | | 710 |
| Total Non-Utility Property and Equipment, Net | $ 2,484 | $ (43) | $ - | $ - | $ 2,441 |

| | December 31, 2002 | Additions | Transfers | Retirements | December 31, 2003 |
|---|---|---|---|---|---|
| Property and Equipment | $ 4,057 | $ 68 | $ - | $ - | $ 4,125 |
| Accumulated Depreciation | (2,036) | (315) | | | (2,351) |
| Total Depreciable Non-Utility Property and Equipment, Net | 2,021 | (247) | - | - | 1,774 |
| Land | 710 | | | | 710 |
| Total Non-Utility Property and Equipment, Net | $ 2,731 | $ (247) | $ - | $ - | $ 2,484 |

Additional information on capital assets can be found in Note C beginning on page 36.

### Outstanding Debt

The Agency's total debt outstanding at December 31, 2004, 2003 and 2002 was $1,985,822,000, $2,027,570,000 and $2,152,928,000, respectively, all of which are revenue bonds. Total debt decreased by $41,905,000 (2.1%) and $125,658,000 (5.8%) during 2004 and 2003, respectively, due to the principal payments made in January in accordance with debt service schedules. In addition, during 2003, total debt decreased due to equity contributions made to facilitate the debt refunding issue.

No debt offerings occurred during 2004.

In March 2003, the Agency refinanced some of its existing debt to take advantage of historically low interest rates. The Agency issued $773,445,000 of Series 2003 A and B Refunding Bonds to refund $802,640,000 of previously issued bonds. The net present value savings realized were $61,748,000 with debt service savings of approximately $6,000,000 per year through 2019.

In April 2003, the Agency issued $149,700,000 of Series 2003C Bonds to refund $181,720,000 of previously issued bonds. The 2003C issue is variable rate debt. To estimate the present value savings and related debt service schedules, the Agency assumed a 3.5% interest rate over the life of the debt. This resulted in net present value savings of $8,859,000 and estimated annual savings between $2,056,000 and $3,669,000 per year through 2018.

In January 2005 the Agency refinanced some of its existing debt to take advantage of lower interest rates. The Agency issued $33,425,000 of Series 2005A and B Refunding Bonds to refund $33,425,000 of previously issued bonds. The net present value savings realized were $2,288,000 with debt service savings of approximately $460,000 per year through 2014.

As a result of continued improvement in the Agency's financial condition, the rating agencies were invited to visit the Agency and some of its member cities during 2004 in order to reevaluate the Agency's rating. The Agency's bond rating improved or stayed the same over the two year period as follows:

- Moody's Investor Service increased the rating from Baa1 (stable) to Baa1 (positive) in January 2003 and to A3 (stable) in December 2004.
- FitchRatings increased from BBB+ (stable) to BBB+ (positive) in January 2003 and to A- (stable) in December 2004.
- Standard and Poor's Corporation rating remained unchanged at BBB+ (stable) throughout the period.

Additional information regarding the Agency's long-term debt can be found in Note F beginning on page 41 of this report.

## Economic Factors and Next Year's Budgets and Rates

### Economic Factors

The following key economic factors played a role in the 2005 budget.

- Over the past year, a continued modest economic recovery has improved demand for electricity. The loss of manufacturing facilities to overseas competitors has played itself out and has been fully accounted for in the forecasts. As the economy picked up over the past year, short-term economic indicators have improved. Key areas of growth affecting the load forecast include housing (residential demand) and high-tech industries.
- Increased fuel costs continue to drive production costs upward. Natural gas prices increased to the \$6/MBTU to \$7/MBTU level, and the forward markets suggest that this trend will remain in place. High natural gas prices are driven by the depletion of wells in the Gulf of Mexico and by the increase in the number of gas-fired generating units. Coal prices have also increased dramatically over the past year due to increasing transportation and mining costs, as well as increased demand for more expensive and cleaner burning low-sulfur coal. With coal and natural gas prices elevated, both on and off-peak electricity prices are expected to remain higher than historical averages.

*Budget Highlights for 2005*

- Implements a 1.0% increase in wholesale rates effective July 1.
- The load forecast estimates energy sales growing 2.3% for 2005.
- Projects that \$39,900,000 of Rate Stabilization Funds will be utilized.
- Projects that \$8,000,000 of the Supplemental Fund Reserve Account will be utilized for credits to large commercial and industrial customers.
- Anticipates scheduled refueling outages for Catawba 1, McGuire 1 and McGuire 2.
- Projects that \$19,100,000 will be spent on capital additions at the Catawba plant.

## Requests for Information

This report is designed to provide an overview of the Agency's finances for those with an interest in this area. Questions concerning any of the information found in this report or requests for additional information should be directed to the Chief Financial Officer, North Carolina Municipal Power Agency Number 1, P.O. Box 29513, Raleigh, NC 27626-0513.

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# NCMPA1 BALANCE SHEETS

**($000s)**

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| **ASSETS** | | |
| **Non-Current Assets** | | |
| Capital Assets (Note C) | | |
| Electric Utility Plant, Net | | |
| Electric plant in service | $ 1,574,459 | $ 1,559,610 |
| Construction work in progress | 13,177 | 18,687 |
| Nuclear fuel | 113,754 | 139,956 |
| Less accumulated depreciation & amortization | (785,622) | (796,322) |
| Total Electric Utility Plant, Net | 915,768 | 921,931 |
| Non-Utility Property and Equipment, Net | | |
| Property and Equipment | 5,088 | 4,835 |
| Less accumulated depreciation | (2,647) | (2,351) |
| Total Non-Utility Property and Equipment, Net | 2,441 | 2,484 |
| Total Capital Assets | 918,209 | 924,415 |
| Restricted Assets | | |
| Special Funds Invested (Notes D and F): | | |
| Bond fund | 314,747 | 286,700 |
| Reserve and contingency fund | 19,229 | 20,003 |
| Special reserve fund | 1,089 | 1,120 |
| Total Special Funds Invested | 335,065 | 307,823 |
| Trust for Decommissioning Costs (Notes D and F) | 185,678 | 169,148 |
| Total Restricted Assets | 520,743 | 476,971 |
| Deferred Costs: | | |
| Unamortized debt issuance costs | 34,186 | 37,395 |
| Costs of advance refundings of debt | 247,568 | 277,310 |
| Other Deferred Costs (Note E) | 397,276 | 408,978 |
| Total Deferred Costs | 679,030 | 723,683 |
| Total Non-Current Assets | 2,117,982 | 2,125,069 |
| **Current Assets** | | |
| Funds Invested (Notes D and F): | | |
| Revenue fund | 167,631 | 161,068 |
| Operating fund | 56,279 | 68,800 |
| Supplemental fund | 128,988 | 142,352 |
| Total Funds Invested | 352,898 | 372,220 |
| Participant accounts receivable | 21,974 | 21,489 |
| Operating accounts receivable | 7,348 | 3,706 |
| Prepaid expenses | 45,875 | 42,438 |
| Derivative financial instruments (Note B) | — | 6,919 |
| Total Current Assets | 428,095 | 446,772 |
| Total Assets | $ 2,546,077 | $ 2,571,841 |

See accompanying notes to financial statements.

# NCMPA1 BALANCE SHEETS

**($000s)**

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| **LIABILITIES AND FUND EQUITY** | | |
| **Liabilities** | | |
| Non-Current Liabilities | | |
| Long-Term Debt: | | |
| Bonds, net of unamortized discount (Note F) | $ 1,914,715 | $ 1,985,665 |
| Less unamortized premium (discount) | 4,322 | 3,932 |
| Total Long-Term Debt | 1,919,037 | 1,989,597 |
| Asset Retirement Obligation | 200,321 | 189,357 |
| Deferred Revenues (Note E) | 278,937 | 271,975 |
| Commitments and Contingencies (Note G) | | |
| Total Non-Current Liabilities | 2,398,295 | 2,450,929 |
| Current Liabilities | | |
| Operating Liabilities: | | |
| Accounts payable | 9,527 | 12,128 |
| Accrued taxes | 15,104 | 14,498 |
| Total Operating Liabilities | 24,631 | 26,626 |
| Special Funds Liabilities: | | |
| Current maturities of bonds (Note F) | 70,950 | 41,905 |
| Accrued interest on bonds | 44,801 | 44,981 |
| Total Special Funds Liabilities | 115,751 | 86,886 |
| Total Current Liabilities | 140,382 | 113,512 |
| Total Liabilities | 2,538,677 | 2,564,441 |
| **Fund Equity** | | |
| Invested in Capital Assets, net of related debt (deficit) | (183,043) | (205,521) |
| Restricted for debt service | 115,274 | 87,714 |
| Unrestricted | 75,169 | 125,207 |
| Total Fund Equity | 7,400 | 7,400 |
| Total Liabilities and Fund Equity | $ 2,546,077 | $ 2,571,841 |

# NCMPA1 STATEMENTS OF REVENUES AND EXPENSES AND CHANGES IN FUND EQUITY

**($000s)**

| | Years Ended December 31, 2004 | 2003 |
|---|---|---|
| **Operating Revenues:** | | |
| Sales of electricity to participants | $ 285,488 | $ 277,581 |
| Sales of electricity to utilities | 77,511 | 73,471 |
| Other revenues (Note H) | 1,133 | 11,962 |
| Total Operating Revenues | 364,132 | 363,014 |
| **Operating Expenses:** | | |
| Operation and maintenance | 75,278 | 86,771 |
| Nuclear fuel | 27,942 | 25,254 |
| Interconnection services: | | |
| Purchased power | 35,054 | 47,650 |
| Transmission and distribution | 15,759 | 16,518 |
| Other | 156 | 162 |
| Total Interconnection services | 50,969 | 64,330 |
| Administrative and general | 37,996 | 34,096 |
| Gross receipts and excise taxes | 12,792 | 10,894 |
| Property tax | 11,308 | 12,339 |
| Depreciation | 21,146 | 21,343 |
| Asset retirement obligation | 10,963 | 14,535 |
| Total Operating Expenses | 248,394 | 269,562 |
| Operating Income | 115,738 | 93,452 |
| **Nonoperating (Revenues) Expenses** | | |
| Investment income | (35,900) | (34,891) |
| Net decrease in fair value of investments and derivative financial instruments | 7,943 | 37,728 |
| Interest expense | 91,689 | 94,682 |
| Amortization of debt refunding costs | 29,742 | 38,194 |
| Amortization of debt discount and issuance costs | 3,600 | 4,751 |
| Net (increase) decrease in other deferred costs (Note E) | 11,702 | (17,629) |
| Net increase in deferred revenues (Note E) | 6,962 | (29,383) |
| Total nonoperating expenses | 115,738 | 93,452 |
| Change in Fund Equity | - | - |
| Fund Equity, Beginning of Year | 7,400 | 7,400 |
| Fund Equity, End of Year | $ 7,400 | $ 7,400 |

See accompanying notes to financial statements.

# NCMPA1 STATEMENTS OF CASH FLOWS

**($000s)**

| | Years Ended December 31, | |
|---|---|---|
| | 2004 | 2003 |
| Cash Flows from Operating Activities: | | |
| Receipts from sales of electricity | $ 358,872 | $ 349,616 |
| Receipts from other revenues | 1,133 | 11,962 |
| Payments of operating expenses | (188,950) | (211,559) |
| Net cash provided by operating activities | 171,055 | 150,019 |
| Cash Flows from Capital and Related Financing Activities: | | |
| Bonds issued | | 923,145 |
| Bonds refunded | | (984,180) |
| Interest paid | (91,869) | (105,319) |
| Additions to electric utility plant and non-utility property and equipment | (47,707) | (44,532) |
| Bonds retired | (41,905) | (64,323) |
| Debt premium net of issuance costs | | 5,405 |
| Net cash used for capital and related financing activities | (181,481) | (269,804) |
| Cash Flows from Investing Activities: | | |
| Sales and maturities of investment securities | 5,795,000 | 7,837,243 |
| Purchases of investment securities | (5,807,070) | (7,740,572) |
| Investment earnings receipts from non-construction funds | 22,494 | 23,110 |
| Net cash provided by investing activities | 10,424 | 119,781 |
| Net Increase (Decrease) in Operating Cash | (2) | (4) |
| Operating Cash, Beginning of year | 2 | 6 |
| Operating Cash, End of year | $ - | $ 2 |

| | | |
|---|---|---|
| Reconciliation of Net Operating Income to Net Cash Provided by Operating Activities: | | |
| Net Operating Income | $ 115,738 | $ 93,452 |
| Adjustments: | | |
| Depreciation | 21,146 | 21,343 |
| Amortization of nuclear fuel | 27,942 | 25,254 |
| Amortization of asset retirement obligation | 10,963 | 14,535 |
| Changes in assets and liabilities: | | |
| Increase in participant accounts receivable | (485) | (842) |
| Increase in operating accounts receivable | (3,642) | (593) |
| Decrease (increase) in prepaid expenses | (3,437) | 3,179 |
| Increase in accounts payable | (2,854) | (3,355) |
| (Increase) decrease in accrued taxes | 5,684 | (2,954) |
| Total Adjustments | 55,317 | 56,567 |
| Net Cash Provided by Operating Activities | $ 171,055 | $ 150,019 |

See accompanying notes to financial statements.

## A. GENERAL MATTERS

North Carolina Municipal Power Agency Number 1 (Agency) is a joint agency organized and existing pursuant to Chapter 159B of the General Statutes of North Carolina to enable municipalities owning electric distribution systems, through the organization of the Agency, to finance, construct, own, operate, and maintain electric generation and transmission facilities. The Agency has nineteen members (Participants) with interests ranging from 0.0869% to 18.9600%, which receive power from the Agency.

### The Project

The Agency has entered into several agreements with Duke Energy Corporation (Duke) which govern the purchase, ownership, construction, operation and maintenance of the project:

The Purchase, Construction and Ownership Agreement provides, among other things, for the Agency to purchase a 75% undivided ownership interest in Unit 2 of the Catawba Nuclear Station (station) and a 37.5% undivided ownership interest in certain support facilities of the station (jointly the project). However, by virtue of various provisions contained in the Interconnection Agreement and the Operation and Fuel Agreement, the Agency (1) bears the costs of acquisition, construction, operation and maintenance of 37.5% of Unit 1 and 37.5% of Unit 2, and (2) has the same proportionate right to the output of and bears the risks associated with the lack of operation of such units.

The Interconnection Agreement provides for the interconnection between Duke's electric power system and the Agency's project and for the exchange of power between Unit 1 and Unit 2 of the station and between the Catawba units and Duke's McGuire Nuclear Station (Reliability Exchanges). Pursuant to the reliability exchanges, project output is provided in essentially equal amounts from Catawba Unit 2 and three other nuclear units (Catawba Unit 1, McGuire Unit 1 and McGuire Unit 2) in operation on the Duke system, all of similar size and capacity. The reliability exchanges are intended to make more reliable the supply of capacity and energy to the Agency in the amount to which the Agency is entitled pursuant to its ownership interest in Catawba Unit 2 and to mitigate potential adverse economic effects on the Agency and the Participants from unscheduled outages of Catawba Unit 2. Correspondingly, the Agency bears risks resulting from unscheduled outages of any Catawba or McGuire Unit.

The Operation and Fuel Agreement provides for Duke to operate, maintain and fuel the station; to make renewals, replacements and capital additions as approved by the Agency; and for the ultimate decommissioning of the station at the end of its useful life.

The Agency's acquisition of its ownership interest is being financed by electric revenue bonds pursuant to Resolution No. R-16-78, as amended, (Resolution) of the Board of Commissioners of the Agency. The Resolution established special funds to hold proceeds from debt issuance, such proceeds to be used for costs of acquisition and construction of the project, for working capital and to establish certain reserves. The Resolution also established special funds in which project revenues are deposited and from which project operating costs, debt service and other specified payments relating to the project are made.

The Agency entered into two power sales agreements with each of its Participants for supplying the total electric power requirements of the Participants in excess of Southeastern Power Administration (SEPA) allocations. With the power generated from the project, together with supplemental purchases of power, the Agency provides the total electric power requirements of its Participants, exclusive of power allotments from SEPA. Under the Project Power Sales Agreements, the Agency sells to the Participants their respective shares of project output. The revenues received relative to the project are pledged as security for bonds issued under the Resolution, after payment of project operating expenses. Each Participant is obligated to pay its share of operating costs and debt service for the project. Under the Supplemental Power Sales Agreements, the Agency supplies each Participant the additional power it requires in excess of that provided by output from the project and from SEPA.

To meet its supplemental power requirements, the Agency entered into a five-year contract with Georgia Power Company (GPC) for the purchase of 125 MW beginning in 2001; into a four-year contract with Dynergy Power Marketing for the purchase of 50 MW beginning in 2003 and a resource management contract with Southern Company which allows the purchase of energy when necessary. In both 2004 and 2003 the Agency purchased energy under the resource management contract with Southern Company. Finally, the Agency has constructed 18.25 MW of Distributed Generation to be called upon as needed.

### ElectriCities of North Carolina, Inc.

ElectriCities of North Carolina, Inc. (ElectriCities), organized as a joint municipal assistance agency under the General Statutes of North Carolina, is a public body and body corporate and politic created for the purpose of providing aid and assistance to municipalities in connection with their electric systems and to joint agencies, such as the Agency.

The Agency has entered into a management agreement with ElectriCities. Under the current management agreement, ElectriCities is required to provide, at cost, all personnel and personnel services necessary for the Agency to conduct its business in an economic and efficient manner. This agreement continues through December 31, 2007, and is automatically renewed for successive three-year periods unless terminated by one year's notice by either party prior to the end of the contract term.

For the years ended December 31, 2004 and 2003, the Agency paid ElectriCities $6,225,000 and $5,865,000, respectively.

## B. SIGNIFICANT ACCOUNTING POLICIES

### Basis of Accounting

The accounts of the Agency are maintained on the accrual basis, in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission, and are in conformity with accounting principles generally accepted in the United States of America (GAAP). The Agency has adopted the principles promulgated by the Governmental Accounting Standards Board (GASB) and Statement of Financial Accounting Standard (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended. This standard allows utilities to capitalize or defer certain costs and/or revenues based upon the Agency's ongoing assessment that it is probable that such items will be recovered through future revenues.

The Agency reports in accordance with GASB Statement No. 34, "Basic Financial Statements – and Management's Discussion and Analysis – for State and Local Governments" (GASB No. 34). The statement requires certain information be included in the financial statements and specifies how that information should be presented.

The financial statements are prepared using the economic resources measurement focus. Operating revenues are defined as revenues received from the sale of electricity and associated services. Revenues from capital and related financing activities and investment activities are defined as non-operating revenues. Restricted equity represents constraints on resources that are imposed by Resolution and may be utilized only for the purposes established by the Resolution. Unrestricted equity may be utilized for any purpose approved by the Board through the budget process. When both restricted and unrestricted equity might be used to meet an obligation, the Agency first uses the restricted equity.

### Financial Reporting

Under 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.

### Electric Plant in Service

All expenditures associated with the development and construction of the Agency's ownership interest in the Catawba station, including interest expense net of investment income on funds not yet expended, have been recorded at original cost and are being depreciated on a straight-line basis over the average composite life of each unit's assets. At December 31, 2004, the remaining life for Catawba Units 1 and 2 was 39 years.

The increase in plant associated with the asset retirement obligation adjustment arising from implementing SFAS No. 143 (discussed under Decommissioning Costs on page 35) is also included. It is being depreciated over the remaining life of the Catawba Units.

In November 2003, GASB issued Statement No. 42, "Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries". Under this statement, governments must report impairment of capital assets. GASB defines impairment as a significant, unexpected decline in the service utility of a capital asset. This statement also covers insurance recoveries, whether connected to a loss or not. The Agency will implement this statement for the year ending December 31, 2006. The Agency has not yet determined what, if any, impact it will have on the Agency's financial statements.

### Construction Work in Progress

All expenditures related to capital additions at Catawba are capitalized as construction work in progress until such time as they are completed and transferred to Electric Plant in Service. No interest is capitalized on capital additions. Depreciation expense is recognized on these items after they are transferred to Electric Plant in Service.

### Nuclear Fuel

All expenditures related to the purchase and construction of the Agency's undivided ownership interests in nuclear fuel cores are capitalized until such time as the cores are placed in the reactor. No interest is capitalized on fuel cores. Once placed in the reactor, they are amortized to fuel expense utilizing the units of production method. Amounts are removed from the books upon disposal of the spent nuclear fuel. Nuclear fuel expense includes a provision for estimated spent nuclear fuel disposal costs which is being collected currently from members. Amortization of nuclear fuel costs includes estimated disposal costs of $6,057,000 and $6,707,000 for the years ended December 31, 2004 and 2003, respectively.

The Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the Department of Energy's (DOE) uranium enrichment plants. Nuclear plant licensees are subject to an annual assessment for 15 years based upon their pro rata share of past enrichment services. Duke makes the annual payment to DOE for the Catawba station and bills the co-owners monthly for their proportionate share. The Agency's payments to Duke were approximately $930,000 and $909,000 in 2004 and 2003, respectively, and were recorded as fuel expense.

Under provisions of the Nuclear Waste Policy Act of 1982, Duke, on behalf of all co-owners of the Catawba station, has entered into contracts with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent nuclear fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and Duke's contract with the DOE. Duke, on behalf of all co-owners, filed a partial breach of contract claim with the United States Court of Federal Claims against the DOE for damages arising out of the DOE's failure to begin accepting the spent nuclear fuel. Claimed damages are intended to recover costs incurred and to be incurred as a result of the DOE's partial material breach of its contract, including costs associated with securing additional spent fuel storage capacity. Duke has plans in place to provide adequate storage capacity until such time as DOE begins receiving spent fuel.

### Non-Utility Property and Equipment

Expenditures related to purchasing and installing an in-house computer, jointly owned with North Carolina Eastern Municipal Power Agency (NCEMPA), were capitalized and are fully depreciated. In addition, the Agency purchased various computer equipment for its load management and telemetry programs which is being depreciated over the estimated useful life of the equipment. Also included are the land and administrative office building jointly owned with North Carolina Eastern Municipal Power Agency and used by both agencies and ElectriCities. The administrative office building is being depreciated over 37 1/2 years on a straight-line basis.

### Investments

The Agency implemented the provisions of GASB Statement No. 31, "Accounting and Financial Reporting for Certain Investments and for External Investment Pools," which requires investments in marketable debt securities to be reported at fair value.

### *Derivative Financial Instruments*

In 1998, the FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Certain Hedging Activities" (SFAS No. 133). In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of SFAS 133" (SFAS No. 138). SFAS No. 133 and SFAS No. 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values. The Agency has implemented SFAS No. 133 and SFAS No. 138.

In 1999 the Agency entered into an interest rate swap agreement with a termination date of December 2009. The swap has not been designated as a hedge. The interest rate swap agreement was entered into to synthetically convert a portion of its fixed rate debt to variable rate debt over the life of the swap. Under the fixed to variable interest rate swap, the Agency receives a fixed rate of 4.984% through the termination date, while paying a variable rate based on the BMA Municipal Swap Index, 1.99% and 1.14% at December 31, 2004 and 2003, respectively. Interest paid and received under the swap agreement increases and decreases, respectively, interest expense. The net effect was to reduce interest expense by $7,546,000 and $7,933,000 in 2004 and 2003, respectively. The notional amount of this agreement is $200,600,000.

Under the original terms, the Agency had the unilateral right to terminate the agreement with appropriate notice. In 2003 the Agency amended the agreement, extending a one-time right to the counterparty to terminate the agreement with no termination payment on January 1, 2005. This option was exercised by the counterparty on January 1, 2005.

The fair value of the interest rate swap agreement was approximately $-0- and $6,919,000 at December 31, 2004 and 2003, respectively. The fair value is the amount that would be paid or received if the swap were terminated and may change as market interest rates change. Current market pricing models were used to estimate the fair value of the interest rate swap agreement. The fluctuation in the fair value of the interest rate swaps was a decrease of $6,919,000 in 2004 due to the option to terminate January 1, 2005 and a decrease of $18,518,000 in 2003 (inclusive of the $11,200,000 payment received from the counterparty to amend the agreement) and is included in "Increase (decrease) in fair value of investments and derivative financial instruments" in the statements of revenues and expenses.

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, is not subject to repayment risk. The Agency minimizes the credit or repayment risk 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.

### Accounts Receivable

Accounts receivable consist of trade accounts receivable associated with the sale of electricity and are stated at cost. The Agency primarily sells to the Participants in the project and accordingly, management does not believe an allowance for doubtful accounts is required.

### Nuclear License Extensions

In December 2003 the NRC granted license extensions for both Catawba units. Thus, the Catawba 1 license was extended from December 2024 to December 2043 and the Catawba 2 license was extended from February 2026 to December 2043.

### Decommissioning Costs

U.S. Nuclear Regulatory Commission (NRC) regulations require that each licensee of a commercial nuclear power reactor furnish to the NRC certification of its financial capability to meet the costs of nuclear decommissioning at the end of the useful life of the licensee's facility. As a co-licensee of Catawba Unit 2, the Agency is subject to these requirements and therefore has furnished certification of its financial capability to fund its share of the costs of nuclear decommissioning of the Catawba Station.

To satisfy the NRC's financial capability regulations, the Agency established an external trust fund (Decommissioning Trust) pursuant to a trust agreement with a bank. The Agency's certification requires that the Agency make annual deposits to the Decommissioning Trust which, together with the investment earnings, amounts previously on deposit in the trust, and certain reserve assets, are anticipated to result in sufficient funds being held in the Decommissioning Trust at the expiration of the current operating licenses for the Catawba Units (2043) to meet the Agency's share of decommissioning.

The Decommissioning Trust is irrevocable and funds may be withdrawn from the trust solely for the purpose of paying the Agency's share of the costs of nuclear decommissioning. Under the NRC regulations, the Decommissioning Trust is required to be segregated from Agency assets and outside the Agency's administrative control. The Agency is deemed to have incurred and paid decommissioning costs as deposits are made to the Decommissioning Trust. In addition to the Decommissioning Trust, certain reserve assets are anticipated to be available to satisfy the Agency's total decommissioning liability.

Estimates of the future costs of decommissioning the units are based on the most recent site-specific study that was conducted on behalf of Duke in 2003. The Agency's portion of decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, is $374,742,000, stated in 2003 dollars.

In 2001 the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). The Agency adopted SFAS No. 143 effective January 1, 2003 as it relates to the decommissioning costs of the Catawba Units 1 and 2 at the end of their operating licenses, December 2043.

SFAS No. 143 requires the Agency 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 assets and record a corresponding asset that will be depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Any such adjustments for changes in the estimated future cash flows will also be capitalized and amortized over the remaining life of the asset.

Changes in components of the asset retirement obligation during 2004 and 2003 are as follows (in thousands of dollars):

| | Years Ended December 31, 2004 | Years Ended December 31, 2003 |
|---|---|---|
| Balance, beginning of year | $ 189,357 | $ 251,031 |
| Liabilities incurred during the year | | |
| Liabilities settled during the year | | |
| Accretion expense | 10,964 | 14,535 |
| Revisions in estimated cash flows | | (76,209) |
| Balance, end of year | $ 200,321 | $ 189,357 |

### Deferred Costs

Unamortized debt issuance costs, shown net of accumulated amortization of $14,217,000 and $11,274,000 at December 31, 2004 and 2003, respectively, are being amortized on the interest method over the term of the related debt. Costs of advance refundings of debt, shown net of accumulated amortization of $214,426,000 and $185,377,000 at December 31, 2004 and 2003, respectively, are deferred and amortized over the term of the debt issued on refunding. Other deferred costs and deferred revenues are not amortized but will be either refunded to or recovered from Participants through future rates (See Note E).

### Premiums/Discounts on Bonds

Premiums (net of discounts) on bonds, shown net of accumulated amortization of $30,579,000 and $30,083,000, at December 31, 2004 and 2003, respectively, are amortized over the terms of the related bonds in a manner that yields a constant rate of interest.

### Taxes

Income of the Agency is excludable from federal income tax under Section 115 of the Internal Revenue Code. Chapter 159B of the General Statutes of North Carolina exempts the Agency from property and franchise or other privilege taxes. In lieu of North Carolina property taxes, the Agency pays an amount that would otherwise be assessed on the non-utility property and equipment of the Agency. In lieu of a franchise or privilege tax, the Agency pays to North Carolina an amount equal to 3.22% of the gross receipts from sales of electricity to Participants. Electric utility property is located in South Carolina and subject to South Carolina property tax. An electric power excise tax equal to .05% (5/10 mill) for each kilowatt-hour of electric power generated and sold for resale within South Carolina is also paid.

### Statements of Cash Flows

For purposes of the statements of cash flows, operating cash consists of unrestricted cash of $2,000 and $2,000 at December 31, 2004 and 2003, respectively, included on the balance sheet in the line item "Current Assets: Funds Invested". Restricted cash of $1,000 and $2,000 at December 31, 2004 and 2003, respectively, included on the balance sheet in the line item "Restricted Assets: Special Funds Invested" is not included on the statements of cash flows.

### Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosures 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.

## C. CAPITAL ASSETS

The Agency has commitments to Duke in connection with capital additions for the station. Current estimates indicate the Agency's portion of these costs for 2005 and 2006 will be approximately $44,429,000.

### Electric Utility Plant, Net

Changes in components of electric utility plant, net during 2004 and 2003 are as follows (in thousands of dollars):

| | December 31, 2003 | Additions | Transfers | Retirements | December 31, 2004 |
|---|---|---|---|---|---|
| Electric Utility Plant | | | | | |
| Electric Plant in Service | $ 1,539,842 | $ - | $ 23,644 | $ (8,795) | $ 1,554,691 |
| Nuclear Fuel | 139,956 | 17,740 | | (43,942) | 113,754 |
| Total Electric Utility Plant | 1,679,798 | 17,740 | 23,644 | (52,737) | 1,668,445 |
| Accumulated Depreciation and Amortization | | | | | |
| Electric Plant in Service | (706,714) | (20,851) | 652 | 8,795 | (718,118) |
| Nuclear Fuel | (89,608) | (21,838) | - | 43,942 | (67,504) |
| Total Accumulated Depreciation and Amortization | (796,322) | (42,689) | 652 | 52,737 | (785,622) |
| Total Depreciable Electric Utility Plant (Net) | 883,476 | 24,949 | 24,296 | - | 882,823 |
| Land and Other Non-Depreciable Assets | | | | | |
| Land | 19,768 | | | | 19,768 |
| Construction Work In Progress | 18,687 | 18,786 | (24,296) | | 13,177 |
| Total Electric Utility Plant (Net) | $ 921,931 | $ (6,163) | $ - | $ - | $ 915,768 |

| | December 31, 2002 | Additions | Transfers | Retirements | December 31, 2003 |
|---|---|---|---|---|---|
| Electric Utility Plant | | | | | |
| Electric Plant in Service | $ 1,430,505 | $ 97,015 | $ 14,060 | $ (1,738) | $ 1,539,842 |
| Nuclear Fuel | 129,407 | 29,130 | | (18,581) | 139,956 |
| Total Electric Utility Plant | 1,559,912 | 126,145 | 14,060 | (20,319) | 1,679,798 |
| Accumulated Depreciation and Amortization | | | | | |
| Electric Plant in Service | (647,035) | (62,127) | 710 | 1,738 | (706,714) |
| Nuclear Fuel | (89,628) | (18,561) | | 18,581 | (89,608) |
| Total Accumulated Depreciation and Amortization | (736,663) | (80,688) | 710 | 20,319 | (796,322) |
| Total Depreciable Electric Utility Plant (Net) | 823,249 | 45,457 | 14,770 | - | 883,476 |
| Land and Other Non-Depreciable Assets | | | | | |
| Land | 19,768 | | | | 19,768 |
| Construction Work In Progress | 19,149 | 14,308 | (14,770) | | 18,687 |
| Total Electric Utility Plant (Net) | $ 862,166 | $ 59,765 | $ - | $ - | $ 921,931 |

Additions in 2003 for electric plant in service and accumulated depreciation include $97,015,000 and $41,099,000, respectively, representing the initial asset retirement obligation adjustment recorded by the Agency in accordance with SFAS No. 143.

### Non-Utility Property and Equipment, Net

Changes in components of non-utility property and equipment during 2004 and 2003 are as follows (in thousands of dollars):

| | December 31, 2003 | Additions | Transfers | Retirements | December 31, 2004 |
|---|---|---|---|---|---|
| Property and Equipment | $ 4,125 | $ 253 | $ - | $ - | $ 4,378 |
| Accumulated Depreciation | (2,351) | (296) | | | (2,647) |
| Total Depreciable Non-Utility Property and Equipment, Net | 1,774 | (43) | - | - | 1,731 |
| Land | 710 | | | | 710 |
| Total Non-Utility Property and Equipment, Net | $ 2,484 | $ (43) | $ - | $ - | $ 2,441 |

| | December 31, 2002 | Additions | Transfers | Retirements | December 31, 2003 |
|---|---|---|---|---|---|
| Property and Equipment | $ 4,057 | $ 68 | $ - | $ - | $ 4,125 |
| Accumulated Depreciation | (2,036) | (315) | | | (2,351) |
| Total Depreciable Non-Utility Property and Equipment, Net | 2,021 | (247) | - | - | 1,774 |
| Land | 710 | | | | 710 |
| Total Non-Utility Property and Equipment, Net | $ 2,731 | $ (247) | $ - | $ - | $ 2,484 |

## D. INVESTMENTS

The Resolution authorizes the Agency to invest in 1) direct obligations of or obligations of which the principal and interest are unconditionally guaranteed by the United States (U.S.), 2) obligations of any agency of the U.S. or corporation wholly owned by the U.S., 3) direct and general obligations of the State of North Carolina or any political subdivision thereof whose securities are rated "A" or better, 4) repurchase agreements with the Bond Fund Trustee, Construction Fund Trustee or any government bond dealer reporting to the Federal Reserve Bank of New York which mature within nine months from the date they were entered into and are collateralized by previously described obligations, and 5) bank time deposits evidenced by certificates of deposit and bankers' acceptances.

Bank time deposits may only be in banks with capital stock, surplus and undivided profits of $20,000,000 or $50,000,000 for North Carolina banks and out-of-state banks, respectively, and the Agency's investments deposited in such banks cannot exceed 50% and 25%, respectively, of such banks' capital stock, surplus and undivided profits.

The Resolution permits the Agency to establish official depositories with any bank or trust company qualified under the laws of North Carolina to receive deposits of public moneys and having capital stock, surplus and undivided profits in excess of $20,000,000.

All depositories must collateralize public deposits in excess of federal depository insurance coverage. The Agency's depositories use the pooling method, a single financial institution collateral pool. Under the pooling method, a depository establishes a single escrow account on behalf of all governmental agencies. Collateral is maintained with an eligible escrow agent in the name of the State Treasurer of North Carolina based on an approved averaging method for demand deposits and the actual current balance for time deposits less the applicable federal depository insurance for each depositor. Responsibility for sufficient collateralization of these excess deposits rests with the financial institutions that have chosen the pooling method. Because of the inability to measure the exact amount of collateral pledged for the Agency under the pooling method, the potential exists for under-collateralization. However, the State Treasurer enforces strict standards for each pooling method depository, which minimizes any risk of under-collateralization. At December 31, 2004 and 2003 the Agency had $3,000 and $4,000, respectively, covered by federal depository insurance.

The Agency's investments are categorized to give an indication of the level of risk assumed by the Agency at year-end. Category 1 includes investments that are insured or registered or for which the securities are held by the Agency or its agent in the Agency's name. Category 2 includes uninsured and unregistered investments for which the securities are held by the broker or dealer, or by its trust department or agent in the Agency's name. Category 3 includes uninsured and unregistered investments for which the securities are held by the broker or dealer, or by its safekeeping department or agent, but not in the Agency's name. All investments except repurchase agreements are considered Category 1. Repurchase agreements are considered Category 3.

The Agency's investments are detailed in the following schedule (in thousands of dollars):

| | December 31, | | | |
|---|---|---|---|---|
| | 2004 | | 2003 | |
| | Cost Basis | Fair Value | Cost Basis | Fair Value |
| Repurchase agreements | $ 207,892 | $ 207,893 | $ 187,138 | $ 187,305 |
| U.S. government securities | | | | |
| U.S. government agencies | 402,352 | 419,328 | 411,893 | 432,086 |
| Municipal bonds | 8,880 | 9,698 | 13,407 | 14,901 |
| Collateralized mortgage obligations | 46,831 | 46,858 | 41,927 | 41,255 |
| Sub-total funds invested | 665,955 | 683,777 | 654,365 | 675,547 |
| Decommissioning Trust securities | 89,514 | 185,638 | 85,288 | 169,148 |
| Cash | | | | |
| Operating cash | 2 | 2 | 2 | 2 |
| Restricted cash | 1 | 1 | 2 | 2 |
| Accrued interest | 4,223 | 4,223 | 4,492 | 4,492 |
| Total funds invested | $ 759,695 | $ 873,641 | $ 744,149 | $ 849,191 |
| Consisting of: | | | | |
| Special funds invested | | $ 335,065 | | $ 307,823 |
| Decommissioning Trust | | 185,678 | | 169,148 |
| Operating assets | | 352,898 | | 372,220 |
| Total funds invested | | $ 873,641 | | $ 849,191 |

In accordance with the provisions of the Resolution, the collateral under the repurchase agreements is segregated and held by the trustee for the Agency.

The Agency's impaired investments are detailed in the following schedule (in thousands of dollars):

| | December 31, 2004 | | | | | |
|---|---|---|---|---|---|---|
| | Less Than 12 Months | | 12 Months or Longer | | Total | |
| | Fair Value | Unrealized Losses | Fair Value | Unrealized Losses | Fair Value | Unrealized Losses |
| Repurchase agreements | $ - | $ - | $ - | $ - | $ - | $ - |
| U.S. government securities | | | | | - | - |
| U.S. government agencies | 49,012 | (917) | 111,230 | (2,708) | 160,242 | (3,625) |
| Municipal bonds | | | | | - | - |
| Collateralized mortgage obligations | 11,881 | (178) | 22,233 | (589) | 34,114 | (767) |
| Sub-total | 60,893 | (1,095) | 133,463 | (3,297) | 194,356 | (4,392) |
| Decommissioning Trust securities | 1,269 | (29) | | | 1,269 | (29) |
| Total | $ 62,162 | $ (1,124) | $ 133,463 | $ (3,297) | $ 195,625 | $ (4,421) |

## E. OTHER DEFERRED COSTS AND DEFERRED REVENUES

Rates for power billings to Participants are designed to cover the Agency's operating expenses, debt requirements and reserves as specified by the Resolution and power sales agreements. Straight-line depreciation and amortization are not considered in the cost of service calculation used to design rates. In addition, certain earnings on funds established in accordance with the Resolution are restricted to those funds and are not available for current operations.

The differences between debt principal maturities (adjusted for the effects of premiums, discounts and amortization of deferred gains and losses) and straight-line depreciation and in interest income recognition are recognized as other deferred costs. When total deferred items exceed principal debt service, other deferred costs increase. When principal debt service exceeds total deferred items, other deferred costs decrease.

Funds collected through rates for reserve accounts and restricted investment income are recognized as deferred revenues, thus increasing deferred revenues. When these funds are used to meet current expenses, deferred revenues decrease.

The Agency's present charges to the Participants, together with planned withdrawals from the RateStabilization Fund and Supplemental Reserve Account are sufficient to recover all of the Agency's current annual costs of the Participants' bulk power needs. Each Participant is required under the power sales agreements to set its rates for its customers at levels sufficient to pay all its costs of its electric utility system, including the Agency's charges for bulk power supply. All Participants have done so.

All rates must be approved by the Board of Commissioners. Rates are designed on an annual basis and are reviewed quarterly. If they are determined to be inadequate to cover the Agency's current annual costs, rates may be revised.

In accordance with SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144),

| Other deferred costs includes the following (in thousands of dollars): | Years Ended December 31, 2004 | Years Ended December 31, 2003 | Inception to December 31, 2004 | Inception to December 31, 2003 |
|---|---|---|---|---|
| Other Deferred Costs | | | | |
| Net deferred interest | $ (206) | $ (190) | $ 152,295 | $ 152,501 |
| Amortization of debt discount and issuance costs | 3,600 | 4,751 | 105,104 | 101,504 |
| Depreciation and amortization | 32,109 | 35,878 | 844,913 | 812,804 |
| Amortization of debt refunding costs | 29,742 | 38,194 | 333,933 | 304,191 |
| Participant billing offsets | (84,890) | (98,732) | (1,000,620) | (915,730) |
| Net decrease (increase) in fair value of investments and derivative financial instruments | 7,943 | 37,728 | (33,027) | (40,970) |
| Asset Retirement Obligation Adjustment | | | (12,018) | (12,018) |
| Training costs | | | 6,696 | 6,696 |
| Total Other Deferred Costs | $ (11,702) | $ 17,629 | $ 397,276 | $ 408,978 |

| Deferred revenues includes the following (in thousands of dollars): | Years Ended December 31, 2004 | Years Ended December 31, 2003 | Inception to December 31, 2004 | Inception to December 31, 2003 |
|---|---|---|---|---|
| Deferred Revenues | | | | |
| Net special funds (withdrawals)/deposits | $ (15,901) | $ (41,292) | $ (4,332) | $ 11,569 |
| Restricted investment income | 22,863 | 22,542 | 418,688 | 395,825 |
| Rate stabilization funds used for other than operations | | (10,633) | (132,473) | (132,473) |
| Special funds excess valuations | | | (2,946) | (2,946) |
| Total Deferred Revenues | $ 6,962 | $ (29,383) | $ 278,937 | $ 271,975 |

the Agency will assess the recoverability of its long lived assets whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. During 2004 and 2003 the Agency determined that such an assessment was not necessary.

## F. BONDS

The Agency has been authorized to issue Catawba Electric Revenue Bonds (bonds) in accordance with the terms, conditions, and limitations of the Resolution. The total to be issued is to be sufficient to pay the costs of acquisition and construction of the project, as defined, and/or for other purposes set forth in the Resolution. Future refunding of bonds may result in the issuance of additional bonds.

The following shows bond activity during 2004.

| | |
|---|---|
| Bonds Outstanding at December 31, 2003 | $ 2,027,570 |
| Principal payments January 1, 2004 | (41,905) |
| Bonds Outstanding at December 31, 2004 | $ 1,985,665 |

The various issues comprising the outstanding debt are as follows (in thousands of dollars):

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| **Series 1992** | | |
| 6% to 8% maturing annually from 2006 to 2011 | $ 199,560 | $ 199,560 |
| Zero coupon priced to yield 6.55% to 6.7% maturing annually from 2008 to 2012 | 100,000 | 100,000 |
| 6% Indexed Caps Bonds maturing in 2012 | 65,300 | 65,300 |
| | 364,860 | 364,860 |
| **Series 1993** | | |
| 4.1% to 5.5% maturing annually from 2005 to 2010 | 117,090 | 117,090 |
| 5% maturing in 2015 with annual sinking fund requirements beginning in 2013 | 33,425 | 33,425 |
| | 150,515 | 150,515 |
| **Series 1995A** | | |
| 5.1% to 5.2% maturing annually from 2007 to 2008 | 15,185 | 15,185 |
| 5.375% maturing in 2020 with annual sinking fund reqirements beginning in 2019 | 64,255 | 64,255 |
| | 79,440 | 79,440 |
| **Series 1997A** | | |
| 5% to 5.125% maturing annually from 2009 to 2011 | 21,115 | 21,115 |
| 5.125% maturing in 2015 with a sinking fund requirement in 2012 | 19,235 | 19,235 |
| 5.125% maturing in 2017 with annual sinking fund requirements beginning in 2016 | 57,425 | 57,425 |
| | 97,775 | 97,775 |

| | December 31, | |
|---|---|---|
| | 2004 | 2003 |
| Series 1998A | | |
| 4.5% to 5.5% maturing annually from 2003 to 2015 | $ 32,430 | $ 32,680 |
| 5.125% maturing in 2017 with annual sinking fund requirements beginning in 2016 | 49,810 | 49,810 |
| 5% maturing in 2020 with annual sinking fund requirements beginning in 2018 | 45,405 | 45,405 |
| | 127,645 | 127,895 |
| Series 1999A | | |
| 5.75% to 6% maturing annually from 2007 to 2010 | 83,340 | 83,340 |
| Series 1999B | | |
| 6.125% to 6.625% maturing annually from 2006 to 2010 | 54,035 | 54,035 |
| 6.375% maturing in 2013 with annual sinking fund requirements beginning in 2011 | 33,585 | 33,585 |
| 6.5% maturing in 2020 with annual sinking fund requirements beginning in 2014 | 112,980 | 112,980 |
| | 200,600 | 200,600 |
| Series 2003A | | |
| 3% maturing in 2005 | 10,000 | 10,000 |
| 5% maturing in 2005 | 25,880 | 25,880 |
| 4.3% maturing in 2011 | 2,500 | 2,500 |
| 5.5% maturing annually from 2011 to 2014 | 148,190 | 148,190 |
| 4.125% maturing in 2014 | 5,000 | 5,000 |
| 5.25% maturing annually from 2014 to 2020 | 506,740 | 506,740 |
| 5% maturing in 2016 | 10,000 | 10,000 |
| 4.5% maturing in 2020 | 5,000 | 5,000 |
| | 713,310 | 713,310 |
| Series 2003B (Federally Taxable) | | |
| 2.95% maturing in 2004 | | 41,655 |
| 3.26% maturing in 2005 | 18,480 | 18,480 |
| | 18,480 | 60,135 |
| Series 2003C-1 (Periodic Auction Reset Securities (PARS) | | |
| Twenty-eight day Thursday auctions, maturing in 2015 with annual sinking fund requirements beginning in 2014 | 40,000 | 40,000 |
| Series 2003C-2 (Periodic Auction Reset Securities (PARS) | | |
| Seven day Wednesday auctions, maturiting in 2018 with manual sinking fund requirements beginning in 2015 | 109,700 | 109,700 |
| | 1,985,665 | 2,027,570 |
| Less: | | |
| Current maturities of bonds | 70,950 | 41,905 |
| Unamortized discount (premium) | (4,322) | (3,932) |
| Total Long-Term Debt | $ 1,919,037 | $ 1,989,597 |

The following table reflects principal debt service included in the designated year's rates. In accordance with the Resolution, these moneys are deposited into the Bond Fund for payment of the following year's current maturities. Debt service deposit requirements for long-term debt outstanding at December 31, 2004 are as follows (in thousands of dollars):

| Year | Principal | Interest | Total |
|---|---|---|---|
| 2005 | $ 87,135 | $ 99,112 | $ 186,247 |
| 2006 | 93,075 | 93,207 | 186,282 |
| 2007 | 98,205 | 87,233 | 185,438 |
| 2008 | 102,565 | 82,963 | 185,528 |
| 2009 | 107,195 | 78,514 | 185,709 |
| 2010 to 2014 | 619,905 | 306,957 | 926,862 |
| 2015 to 2019 | 806,635 | 132,240 | 938,875 |
| Total | $ 1,914,715 | $ 880,226 | $ 2,794,941 |

Current maturities of $70,950,000 at December 31, 2004 were collected through rates during 2004 and were deposited monthly into the Bond Fund to make the January 1, 2005 principal payment.

The fair market value of the Agency's long-term debt was estimated using a yield curve derived from December 31, 2004 and 2003 market prices for similar securities. Using these yield curves, market prices were estimated for each individual maturity and the individual maturities were summed to arrive at an estimated fair market value of $2,100,822,000 and $2,197,158,000 at December 31, 2004 and 2003, respectively.

Certain proceeds of the Series 1984 (subsequently paid at maturity or refunded), 1992, 1993, 1995A, 1997A, 1998A, 1999A and 2003A, B and C bonds were used to establish trusts for the refunding of $3,316,190,000 of previously issued bonds. At December 31, 2004, $3,100,350,000 of these bonds has been redeemed leaving $215,840,000 still outstanding. Under these Refunding Trust Agreements, obligations of, or guaranteed by, the United States have been placed in irrevocable Refunding Trust Funds maintained by the Bond Fund Trustee. The government obligations in the respective Refunding Trust Funds along with the interest earnings on such obligations, will be sufficient to pay all interest on the refunded bonds when due and to redeem all refunded bonds at various dates prior to their original maturities at par. The monies on deposit in each Refunding Trust Fund, including the interest earnings thereon, are pledged solely for the benefit of the holders of the refunded bonds. Since the establishment of each Refunding Trust Fund, the refunded bonds are no longer considered outstanding obligations of the Agency.

Except for the Series 2003C Bonds, interest on the bonds is payable semi-annually. Interest for the previous auction period on the Series 2003C-1 Bonds is payable on the Friday after each auction date. Interest for the previous auction period on the Series 2003C-2 Bonds is payable on the Thursday after each auction date.

Certain of the following bonds are subject to redemption prior to maturity at the option of the Agency, on or after the following dates at a maximum of 102% of the respective principal amounts:

| | |
|---|---|
| Series 1993 | January 1, 2003 |
| Series 1995A | January 1, 2006 |
| Series 1997A | January 1, 2007 |
| Series 1998A | January 1, 2008 |
| Series 1999B | January 1, 2010 |
| Series 2003A | January 1, 2013 |
| Series 2003C | Any Interest Payment Date |

The bonds are special obligations of the Agency, payable solely from and secured solely by (1) project revenues (as defined by the Resolution) after payment of project operating expenses (as defined by the Resolution) and (2) other monies and securities pledged for payment thereof by the Resolution.

The Resolution requires the Agency to deposit into special funds all proceeds of bonds issued and all project revenues (as defined by the Resolution) generated as a result of the Project Power Sales Agreements and Interconnection Agreement. The purpose of the individual funds is specifically defined in the Resolution.

In January 2005 the Agency refinanced some of its existing debt to take advantage of lower interest rates. The Agency issued $33,425,000 of Series 2005A and B Refunding Bonds to refund $33,425,000 of previously issued bonds. The net present value savings realized were $2,288,000 with debt service savings of approximately $460,000 per year through 2014.

## G. COMMITMENTS AND CONTINGENCIES

The Price-Anderson Act limits the public liability for a nuclear incident at a nuclear generating unit to $10,800,000,000, which amount is to be covered by private insurance of $300,000,000 and agreements of indemnity with the NRC for the remainder. Such private insurance and agreements of indemnity are carried by Duke on behalf of all co-owners of the station. The terms of this coverage require the owners of all licensed facilities to provide up to $100,600,000 per year per unit owned (adjusted annually for inflation) in the event of any nuclear incident involving any licensed facility in the nation, with an annual maximum assessment of $10,000,000 per unit owned. If any such payments are required, the Agency would be liable for 37.5% of those payments applicable to the station.

The Price Anderson Act was first enacted in 1957 and has been renewed three times, the last in 1998. The Act expired in 2002 but nuclear reactors in operation when the Act expired remain covered by the law. Congress is currently holding hearings considering reauthorization of the legislation that could include increased limits and assessments per unit owned. The final outcome of this matter cannot be predicted at this time.

Primary property damage insurance coverage purchased for the station is $500,000,000. Excess property damage, decontamination and decommissioning liability insurance of $2,750,000,000 has also been purchased.

## H. OTHER REVENUES

Other revenues include $1,133,000 and $11,962,000 in 2004 and 2003, respectively, which were received from Duke in settlements of arbitration issues and from the gain on the interest rate swap amendment.

# NCMPA1 SCHEDULES OF REVENUES AND EXPENSES PER BOND RESOLUTION AND OTHER AGREEMENTS

**($000s)**

| | Year Ended December 31, 2004 | | | Year Ended December 31, 2003 | | |
|---|---|---|---|---|---|---|
| | Project | Supplemental | Total | Project | Supplemental | Total |
| **Revenues:** | | | | | | |
| Sales to participants | $ 260,639 | $ 24,849 | $ 285,488 | $ 242,155 | $ 35,426 | $ 277,581 |
| Sales to utilities | 77,511 | | 77,511 | 71,194 | 2,277 | 73,471 |
| Investment income | 12,478 | 559 | 13,037 | 11,600 | 749 | 12,349 |
| Excess Reserve & Contingency Fund valuation | | | - | 6,175 | | 6,175 |
| Rate Stabilization Fund withdrawal | 7,915 | | 7,915 | 33,293 | | 33,293 |
| Supplemental Fund - Reserve Account withdrawal | | 7,986 | 7,986 | | 7,999 | 7,999 |
| Other revenue | 1,077 | 56 | 1,133 | 11,908 | 54 | 11,962 |
| Total Revenues | 359,620 | 33,450 | 393,070 | 376,325 | 46,505 | 422,830 |
| **Expenses:** | | | | | | |
| Operation and maintenance | 77,969 | 113 | 78,082 | 87,221 | 147 | 87,368 |
| Nuclear fuel | 17,896 | | 17,896 | 15,161 | | 15,161 |
| Fossil fuel | | 46 | 46 | | 93 | 93 |
| Interconnection services: | | | | | | |
| Purchased power | 24,620 | 10,434 | 35,054 | 25,380 | 22,270 | 47,650 |
| Transmission and distribution | | 15,759 | 15,759 | | 16,518 | 16,518 |
| Other | | 156 | 156 | | 162 | 162 |
| Total interconnection services | 24,620 | 26,349 | 50,969 | 25,380 | 38,950 | 64,330 |
| Administrative and general – Duke | 28,340 | | 28,340 | 24,401 | | 24,401 |
| Administrative and general – Agency | 3,706 | 5,057 | 8,763 | 2,910 | 2,944 | 5,854 |
| Miscellaneous Agency expenses | | 893 | 893 | 771 | 3,070 | 3,841 |
| Gross receipts and excise taxes | 10,522 | 786 | 11,038 | 9,783 | 1,111 | 10,894 |
| Property tax | 12,792 | | 12,792 | 12,339 | | 12,339 |
| Debt service | 162,639 | 206 | 162,845 | 176,138 | 190 | 176,328 |
| Special funds deposits: | | | | | | |
| Decommissioning fund | 3,560 | | 3,560 | 3,903 | | 3,903 |
| Reserve and contingency fund | 17,576 | | 17,576 | 18,318 | | 18,318 |
| Total special funds deposits | 21,136 | - | 21,136 | 22,221 | - | 22,221 |
| Total Expenses | 359,620 | 33,450 | 393,070 | 376,325 | 46,505 | 422,830 |
| Excess of Revenues Over Expenses | $ - | $ - | $ - | $ - | $ - | $ - |

Note: The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2004 and 2003.

See accompanying Independent Auditors' Report.

# NCMPA1 SCHEDULE OF BUDGETARY COMPARISON

**Years Ended December 31, 2004 and 2003**

**($000s)**

| | Budget | | Actuals (Budgetary Basis) | Positive (Negative) Variance With Final Budget |
|---|---|---|---|---|
| | Original | Final | | |
| Revenues: | | | | |
| Sales to participants | $ 292,843 | $ 292,843 | $ 285,488 | $ (7,355) |
| Sales to utilities | 62,920 | 62,920 | 77,511 | 14,591 |
| Investment income | 14,837 | 14,837 | 13,037 | (1,800) |
| Excess Reserve & Contingency Fund Valuation | 1,736 | 1,736 | - | (1,736) |
| Rate Stabilization Fund withdrawal | 37,560 | 37,560 | 7,915 | (29,645) |
| Supplemental Fund - Reserve Account withdrawal | 8,053 | 8,053 | 7,986 | (67) |
| Other revenues | 50 | 50 | 1,133 | 1,083 |
| Total Revenues | 417,999 | 417,999 | 393,070 | (24,929) |
| Expenses: | | | | |
| Operations & maintenance | 75,421 | 75,421 | 78,082 | (2,661) |
| Nuclear fuel | 19,390 | 19,390 | 17,896 | 1,494 |
| Fossil fuel | 400 | 400 | 46 | 354 |
| Interconnection services: | | - | | |
| Purchased power | 53,698 | 53,698 | 35,054 | 18,645 |
| Transmission & distribution | 18,223 | 18,223 | 15,759 | 2,463 |
| Other interconnection expenses | 117 | 117 | 156 | (39) |
| Total interconnection services | 72,038 | 72,038 | 50,969 | 21,069 |
| Administrative and general – Duke | 24,684 | 24,684 | 28,340 | (3,656) |
| Power Agency services | 12,868 | 12,868 | 8,763 | 4,105 |
| Miscellaneous Agency Expenses | | | 893 | (893) |
| Taxes | 25,091 | 25,091 | 24,100 | 991 |
| Debt service | 166,628 | 166,628 | 162,845 | 3,783 |
| Special funds deposits | 21,479 | 21,479 | 21,136 | 343 |
| Total Expenses | 417,999 | 417,999 | 392,177 | 25,822 |
| Excess of Revenues Over Expenses | $ - | $ - | $ - | $ - |

Note: The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2003.

See accompanying Independent Auditors' Report.

# NCMPA1 SCHEDULES OF CHANGES IN ASSETS OF FUNDS INVESTED

**($000s)**

| | Funds Invested January 1, 2003 | Debt Proceeds | Power Billing Receipts | Investment Income | Disburse-ments | Transfers | Funds Invested December 31, 2003 | Power Billing Receipts | Investment Income | Disburse-ments | Transfers | Funds Invested December 31, 2004 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Bond Fund: | | | | | | | | | | | | |
| Interest account | $ 59,262 | $ - | $ - | $ 232 | (112,092) | $ 103,238 | $ 50,640 | $ - | 330 | $ (99,115) | $ 98,113 | $ 49,968 |
| Reserve account | 197,095 | (5,414) | | 9,504 | | (9,215) | 191,970 | | 9,228 | | (8,832) | 192,366 |
| Principal account | 64,400 | | | 188 | (73,177) | 50,586 | 41,997 | | 527 | (41,905) | 70,459 | 71,078 |
| | 320,757 | (5,414) | - | 9,924 | (185,269) | 144,609 | 284,607 | | 10,085 | (141,020) | 159,740 | 313,412 |
| Reserve and Contingency Fund: | 34,669 | (541) | | 800 | (3,665) | (11,268) | 19,995 | | 581 | (18,017) | 16,765 | 19,324 |
| Special Reserve Fund | 1,071 | | | 48 | | (56) | 1,063 | | 51 | | (55) | 1,059 |
| Revenue Fund | | | | | | | | | | | | |
| Revenue account | (8138) | | 233,123 | 80 | 35 | (220,145) | 4,955 | 269,671 | 134 | 42,203 | (303,760) | 13,203 |
| Rate stabilization account | 185,644 | | | 8,177 | | (43,927) | 149,894 | | 7,601 | | (7,915) | 149,580 |
| | 177,506 | | 233,123 | 8,257 | 35 | (264,072) | 154,849 | 269,671 | 7,735 | 42,203 | (311,675) | 162,783 |
| Operating Fund: | | | | | | | | | | | | |
| Working Capital account | 25,501 | | | 2,005 | (188,491) | 187,081 | 26,096 | | 1,707 | (128,473) | 129,320 | 28,650 |
| Fuel account | 72,365 | | | | 3,388 | (34,172) | 41,581 | | | (29,093) | 14,824 | 27,312 |
| | 97,866 | - | - | 2,005 | (185,103) | 152,909 | 67,677 | - | 1,707 | (157,566) | 144,144 | 55,962 |
| Supplemental Fund: | | | | | | | | | | | | |
| Supplemental account | 26,486 | | 44,137 | 700 | (22,858) | (14,124) | 34,341 | 15,838 | 506 | (25,122) | (936) | 24,627 |
| Supplemental Reserve Account | 111,415 | | | 4,390 | | (7,998) | 107,807 | | 4,456 | | (7,983) | 104,280 |
| | 137,901 | - | 44,137 | 5,090 | ((22,858) | (22,122) | 142,148 | 15,838 | 4,962 | (25,122) | (8,919) | 128,907 |
| | $ 769,770 | $ (5,955) | $ 277,260 | $ 26,124 | $ (396,860) | $ - | $670,339 | $ 285,509 | $ 25,121 | $ 299,522 | $ - | $ 681,447 |

Note: The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2004 and 2003.

See accompanying Independent Auditors' Report.

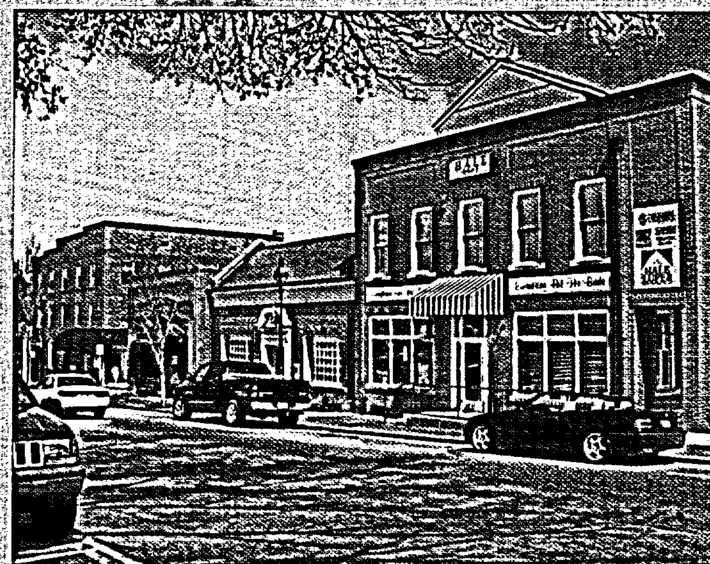
# NCMPA1 STATISTICAL HIGHLIGHTS

**Ten Years at a Glance (Unaudited)**

| | 2004 | 2003 | 2002 | 2001 | 2000 |
|---|---|---|---|---|---|
| Megawatt-hour Sales (MWh) | 4,845,911 | 4,747,018 | 4,806,117 | 4,638,350 | 4,749,523 |
| Peak Billing Demand (kW) | 838,034 | 930,103 | 897,878 | 856,577 | 894,324 |
| Operating Revenues | $364,132,000 | $363,014,000 | $335,230,000 | $324,454,000 | $324,946,000 |
| Excess (Deficiency) of Revenues over Expenditures | $0 | $0 | $0 | $0 | $0 |
| Sales to Utilities (Revenues) | $77,511,000 | $73,471,000 | $57,704,000 | $62,616,000 | $55,759,000 |
| Average Monthly Power Purchases by Cities (MWh) | 403,826 | 395,585 | 400,510 | 386,529 | 395,794 |
| Average Monthly Billings to Cities | $23,791,000 | $23,132,000 | $23,032,000 | $21,755,000 | $21,827,000 |

| | 1999 | 1998 | 1997 | 1996 | 1995 |
|---|---|---|---|---|---|
| Megawatt-hour Sales (MWh) | 4,567,636 | 4,496,603 | 4,223,699 | 4,221,890 | 4,125,029 |
| Peak Billing Demand (kW) | 882,083 | 842,892 | 853,384 | 829,245 | 803,615 |
| Operating Revenues | $347,476,000 | $361,131,000 | $367,130,000 | $375,577,000 | $413,852,000 |
| Excess (Deficiency) of Revenues over Expenditures | $0 | $0 | $0 | $0 | $0 |
| Sales to Utilities (Revenues) | $85,097,000 | $102,551,000 | $119,698,000 | $134,453,000 | $183,554,000 |
| Average Monthly Power Purchases by Cities (MWh) | 380,636 | 374,717 | 351,975 | 351,824 | 343,752 |
| Average Monthly Billings to Cities | $21,734,000 | $21,439,000 | $20,514,000 | $19,942,000 | $19,077,000 |

# North Carolina Eastern Municipal Power Agency



Downtown Wake Forest


Mark S. Williams
*NCEMPA Chairman*
Wake Forest

"Overall, NCEMPA achieved cost savings of $55 million during 2004. These savings proved critical to maintaining NCEMPA participant rates."

# Letter to the Stakeholders
*From the Chairman*

A series of successful initiatives in 2004 combined to ensure that North Carolina Eastern Municipal Power Agency (NCEMPA) rates were as low as possible. A new procedure to review contracts, development of a mutually beneficial partnership with Progress Energy Carolinas (PEC) and continued excellent plant operations in the NCEMPA co-owned facilities combined to make 2004 an excellent year.

Overall, NCEMPA achieved cost savings of $55 million during 2004. Demand-side management savings for the year were $33 million, which in addition to other cost-savings initiatives, helped hold down rate increases. These savings proved critical to maintaining NCEMPA participant rates. Additional savings resulted from a mid-year bond refunding.

A new process was developed to monitor and review coal costs for NCEMPA's coal plants. These new procedures will help NCEMPA monitor and anticipate changes to the cost of coal as conditions change in the world and national markets. Additionally, new procedures implemented change the way PEC accounts for and manages our NCEMPA contracts, including those with the coal plants, nuclear plants and contract purchases. These procedures ensure the Agency pays its appropriate share of costs.

NCEMPA continues to work very closely with PEC, as a business partner in the operation of the generating facilities and with supplemental power supply contracts. The relationship between NCEMPA and PEC has proven to be mutually beneficial to both parties and to our member cities. Constant communications improves the flow of information which effectively reduces NCEMPA's operating costs.

The plants had a productive year in 2004, keeping power agency costs as low as possible with a good mix of fossil and nuclear power. Brunswick Units 1 and 2 hit yet another record for generation since the plant began operation. Brunswick Nuclear Plant was honored in October 2004 by GE Energy for having two of the world's top sustained generation boiling water reactors. In 2004, Harris Nuclear Plant logged over 7 million man-hours without a lost-time accident.

In October 2004, PEC submitted a license renewal application to the Nuclear Regulatory Commission requesting a 20-year operating license renewal for the Brunswick Nuclear Plant. The current 40-year operating license for Brunswick Unit 1 expires September 8, 2016 and Unit 2 expires December 27, 2014. An extension of the lifetime for operations will provide substantial additional value to our member cities and our citizens. Nuclear plants continue to provide clean, reliable and affordable energy.

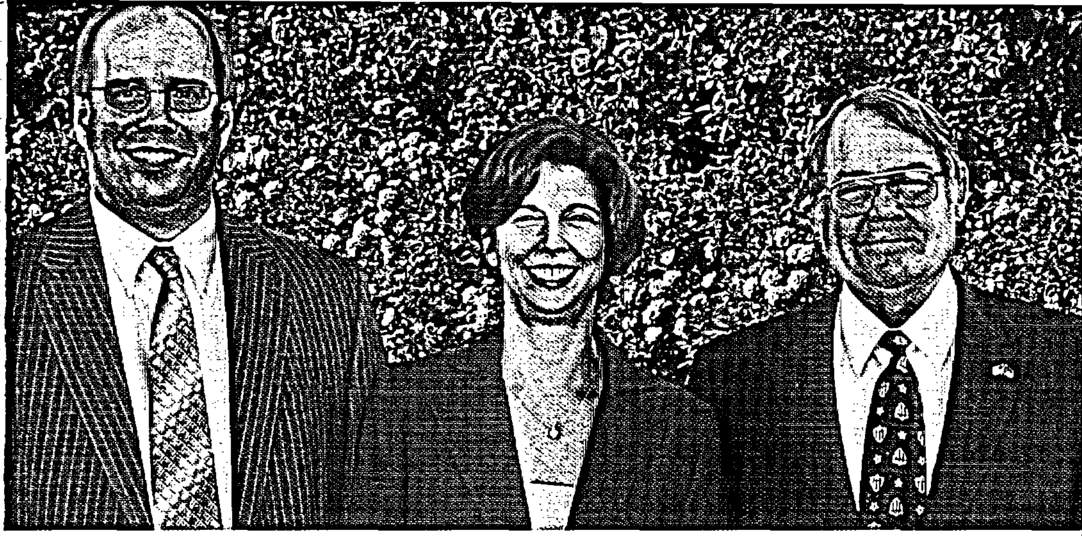
NCEMPA continued to provide member education about new trends and innovations in public power. Workshops offered information about automated meter reading systems, an innovative new system that brings time and cost savings for member cities. Several member cities began automated meter reading programs in 2004 and NCEMPA continues to offer individual reviews and participant workshops for billing process assurance and performance indicators.

NCEMPA member cities joined together to be excluded from a proposal requiring some of the member cities in the Virginia Electric Power Company (VEPCO), now Dominion North Carolina, region to join a regional transmission organization (RTO). In 2004, Dominion North Carolina began a process that was mandated by the State of Virginia's Legislature to join the PJM RTO. NCEMPA staff negotiated to exclude its nine cities from joining PJM, a cost-saving effort to avoid costs associated with RTO management and operation. The Agency successfully secured a positive ruling from the Federal Energy Regulatory Commission and the North Carolina Utilities Commission and was granted exclusion from PJM.

Economic development efforts, a major focus in all public power cities, were successful in our cities in 2004. In total, the Agency achieved more than $75 million in investment, the addition of 1,017 jobs and 13 MW of electric load. A few of the year's economic development highlights include Carolina Classic in Edenton, Metaldyne in Greenville, Home Depot in Rocky Mount and Smithfield Packing in Kinston. Economic development prospects are already promising for the coming year as well.

NCEMPA cities are experiencing electric load growth, and, as a result, are working to upgrade and expand delivery facilities. Several city systems expanded, including Apex, Wake Forest, Clayton and Tarboro. NCEMPA worked with PEC and Dominion North Carolina to expand and increase capacity to meet the needs of the growing communities.

As you can see, 2004 was an exciting year where we met challenges and kept our eyes on costs. Through our strength in collaboration, economic development is vibrant. As we move through the years, it is my hope that we continue to stay focused on the future and plan with vision and innovation for the benefit of our communities and citizens.



**Mark S. Williams**
*Chairman*
Wake Forest

**Anne-Marie Knighton**
*Secretary-Treasurer*
Edenton

**L. Stewart Rumley**
*Vice Chairman*
Washington

## 2004 NCEMPA Board of Commissioners

*Alternate commissioners' names appear in italics*

**Apex**
Mr. Bruce A. Radford
*Mr. J. Michael Wilson*

**Ayden**
Mr. H. Dewitt Hardison
*Mr. Adam Mitchell*

**Belhaven**
Mr. Timothy M. Johnson
*First Alternate Vacant*

**Benson**
Mr. Keith R. Langdon
*Mayor Don H. Johnson*

**Clayton**
Mr. Robert J. Ahlert
*Mr. Alex Harding*

**Edenton**
Ms. Anne-Marie Knighton
*Mr. William A. Crummey*

**Elizabeth City**
Ms. Cecilia C. Austin
*First Alternate Vacant*

**Farmville**
Mr. Richard N. Hicks
*Mr. J. Don Riddle*

**Fremont**
Commisioner Vacant
*Mr. Billy Harvey*

**Greenville**
Mr. J. Wayne Powell
*Mr. Richard Miller*

**Hamilton**
Mr. Herbert L. Everett
*Mayor Donald G. Matthews III*

**Hertford**
Mr. John Christensen
*Mayor James Sidney "Sid" Eley*

**Hobgood**
Ms. Stella Daugherty
*Mayor Timothy D. Purvis*

**Hookerton**
Mr. Sam Johnson
*Mr. Morris Luckett*

**Kinston**
Mr. Ralph A. Clark
*Mr. Scott Stevens*

**La Grange**
Mr. Larry Gladney
*Mr. Bobby Wooten*

**Laurinburg**
Mr. Joseph R. Huffman
*Mayor Ann B. Slaughter*

**Louisburg**
Mr. C. L. Gobble
*Ms. Lois Brown Wheless*

**Lumberton**
Mr. Harry L. Ivey
*Mr. J. Franklin Price*

**New Bern**
Mr. Ralph E. Puckett
*Mr. Walter B. Hartman, Jr.*

**Pikeville**
Mr. Herb Sieger
*Ms. Kathie Fields*

**Red Springs**
Mr. John McNeill
*Mr. T. Wayne Horne*

**Robersonville**
Mr. John H. Pritchard, Jr.
*Mr. John David Jenkins*

**Rocky Mount**
Ms. Angela R. Bryant
*Mr. Stephen W. Raper*

**Scotland Neck**
Mayor Robert B. Partin
*First Alternate Vacant*

**Selma**
Mr. Jeffrey C. White
*Mr. Donald Baker*

**Smithfield**
Mr. Peter T. Connet
*Mr. Robert E. Tripp*

**Southport**
Mr. Paul D. Fisher
*Mr. Robert W. Grant*

**Tarboro**
Mr. Samuel W. Noble, Jr.
*Mr. Ricky C. Page*

**Wake Forest**
Mr. Mark S. Williams
*Mr. David Camacho*

**Washington**
Mr. Steven L. Harrell
*Mayor L Stewart Rumley*

**Wilson**
Mayor C. Bruce Rose
*Mr. Charles W. Pittman, III*

# NCEMPA ELECTRIC SYSTEM PARTICIPANTS

| City | Year | Revenues | Customers | % Ownership |
|---|---|---|---|---|
| Apex | 2004 | $16,016,610 | 10,475 | 0.706% |
| | 2003 | $15,346,046 | | |
| Ayden | 2004 | $8,687,520 | 3,695 | 1.134% |
| | 2003 | $9,635,332 | | |
| Belhaven | 2004 | $2,500,039 | 1,116 | 0.409% |
| | 2003 | $2,440,700 | | |
| Benson | 2004 | $4,020,783 | 1,802 | 0.577% |
| | 2003 | $4,020,783 | | |
| Clayton | 2004 | $8,299,260 | 4,227 | 0.745% |
| | 2003 | $9,135,999 | | |
| Edenton | 2004 | $9,471,720 | 3,940 | 1.596% |
| | 2003 | $9,447,263 | | |
| Elizabeth City | 2004 | $26,535,716 | 10,058 | 4.251% |
| | 2003 | $26,235,664 | | |
| Farmville | 2004 | $6,010,196 | 2,949 | 1.290% |
| | 2003 | $5,704,166 | | |
| Fremont | 2004 | $1,253,365 | 862 | 0.306% |
| | 2003 | $1,275,070 | | |
| Greenville | 2004 | $130,812,845 | 53,002 | 16.134% |
| | 2003 | $132,122,844 | | |
| Hamilton | 2004 | $401,809 | 254 | 0.078% |
| | 2003 | $367,145 | | |
| Hertford | 2004 | $2,304,284 | 1,231 | 0.412% |
| | 2003 | $2,426,452 | | |
| Hobgood | 2004 | $547,668 | 319 | 0.091% |
| | 2003 | $482,585 | | |
| Hookerton | 2004 | $600,973 | 431 | 0.155% |
| | 2003 | $645,999 | | |
| Kinston | 2004 | $38,468,689 | 12,295 | 8.668% |
| | 2003 | $39,124,614 | | |
| La Grange | 2004 | $2,660,216 | 1,538 | 0.501% |
| | 2003 | $2,856,405 | | |
| Laurinburg | 2004 | $13,519,774 | 5,681 | 2.267% |
| | 2003 | $13,539,145 | | |
| Louisburg | 2004 | $5,068,005 | 1,939 | 0.858% |
| | 2003 | $5,694,874 | | |
| Lumberton | 2004 | $27,730,673 | 9,567 | 5.157% |
| | 2003 | $26,266,800 | | |
| New Bern | 2004 | $43,457,744 | 18,169 | 6.368% |
| | 2003 | $42,913,536 | | |
| Pikeville | 2004 | $835,397 | 527 | 0.205% |
| | 2003 | $836,958 | | |
| Red Springs | 2004 | $6,120,348 | 1,699 | 0.580% |
| | 2003 | $3,629,213 | | |
| Robersonville | 2004 | $4,506,000 | 1,068 | 0.507% |
| | 2003 | $2,233,855 | | |
| Rocky Mount | 2004 | $68,069,167 | 30,477 | 16.026% |
| | 2003 | $68,690,602 | | |
| Scotland Neck | 2004 | $2,465,402 | 1,731 | 0.576% |
| | 2003 | $3,006,194 | | |
| Selma | 2004 | $6,203,502 | 2,736 | 0.810% |
| | 2003 | $6,024,475 | | |
| Smithfield | 2004 | $15,014,225 | 4,432 | 2.006% |
| | 2003 | $14,657,930 | | |
| Southport | 2004 | $6,728,464 | 2,239 | 0.714% |
| | 2003 | $4,735,520 | | |
| Tarboro | 2004 | $21,897,476 | 5,942 | 4.743% |
| | 2003 | $21,379,961 | | |
| Wake Forest | 2004 | not available | 5,950 | 0.726% |
| | 2003 | $11,234,615 | | |
| Washington | 2004 | $26,498,887 | 12,692 | 5.892% |
| | 2003 | $23,010,628 | | |
| Wilson | 2004 | $99,420,393 | 32,904 | 15.512% |
| | 2003 | $100,163,547 | | |

### Load Management and Power Operations

NCEMPA staff and the participants again successfully controlled load during each month's peak billing period in 2004. This success translated into power cost savings of over $33 million dollars throughout the year. NCEMPA recommended load management an average of 8.6 hours per month, during approximately four days each month. NCEMPA participants and their customers shed a monthly average of over 220 MW, with over 250 MW shed during the maximum peak hours. Load Side Generation is an integral part of this load shedding process with over 177 MW of generation noticed as of December 2004.

Some members saw expansion of power delivery facilities during 2004 including new delivery point construction for Apex and expansion planning for Wake Forest, Selma, Smithfield, Rocky Mount, Wilson and Benson.

NCEMPA and participant staff continued to develop improved systems and communication alternatives for load management operations. The participants and their customers utilize more than 10 different paging and mobile service companies. NCEMPA staff makes over 190,000 pages, telephone calls and email communications through these different companies each year, providing load management recommendations and information.

### Energy and Demand

Energy Consumption for 2004 set a new record at 7,185,123 MWh (net of SEPA). The previous Energy Consumption record was set in 2002 at 7,060,340 MWh. The highest monthly Energy Consumption for 2004 occurred in July at 741,491 MWh. The previous monthly record was set in August 2003 at 732,543 MWh.

The highest Coincident Peak Demand for 2004 was 1,257 MW during the month of July (net of SEPA). The record for Coincident Peak Demand was set in July 2002 at 1,320 MW. The average Coincident Peak load factor for 2004 was 84 percent, a slight increase from the 2003 average of 83 percent.

The 2004 maximum Non-Coincident Peak Demand was 1,366 MW set in the month of July (net of SEPA). The all-time Non-Coincident Peak Demand record was set in July 2002 at 1,455 MW.

### Environmental Regulations

NCEMPA and Progress Energy Carolinas, Inc. (PEC) have continued to take significant steps to improve the environmental performance of the jointly owned units.

On June 20, 2002, Senate Bill 1078, titled "Improve Air Quality/Electric Utilities" (the Clean Smokestacks Legislation), was signed into law. This law sets limits on PEC emissions of sulphur dioxide and nitrogen oxide from their coal-fired generating units in any calendar year. PEC and NCEMPA addressed this legislation by implementing a plan to achieve compliance with both the nitrogen oxide and sulphur dioxide emission limitations using the most economical combination of compliance alternatives. PEC decided to bring its total system into compliance in the most cost-effective manner. This will result in "over compliance" at the NCEMPA's jointly owned fossil units.

Through our Clean Air Act Agreement with PEC and an Amendment signed in December 2002, the sulphur dioxide compliance emission issue is being addressed by the installation of "scubbers" at Mayo Unit 1 and Roxboro Unit 4, with the potential to lower sulphur dioxide emissions by 90 percent. The capital additions cost of NCEMPA's share of the scrubbers has been capped and any "over compliance" sulphur dioxide emission excess allowances will be transferred to NCEMPA.

PEC's current nitrogen oxide compliance plan included the installation of Selective Catalytic Reduction (SCR) technology, installed on both Roxboro Unit 4 and the Mayo Unit 1 coal burning facilities. These devices can reduce nitrogen oxide emissions by more than 85 percent when used with low–nitrogen oxide burners. Through this, the first installation of SCR's on coal–burning facilities in the Carolinas, PEC intends to "overcomply" at these units in order to ensure that all of the coal-fired generating units owned and operated by PEC achieve compliance in the most cost effective manner. PEC has agreed to credit the Power Agency for nitrogen oxide "over compliance" with the legislation.

### Economic Development

The Eastern North Carolina cities had a very successful year in industrial recruitment and expansion of their existing industries. NCEMPA members added 1,017 new jobs in 2004 to their communities with investments totaling $75.7M. New load added to the Agency was 13 MW. Staff continues to work closely with the Department of Commerce, local developers and the regional partnerships to further the strategic load growth efforts in our communities.

Emphasis was placed on Target Marketing Plans for the cities. The main focus of these plans is to provide strategies, industry targets and specific action steps necessary for each community to successfully pursue the recruitment of new businesses and industries. Completion of the plan will enhance the systematic growth of each city's electric system by prioritizing opportunities for new load additions and focusing efforts on assisting members with expanding their business recruitment and expansion efforts. Elements of the plans include: Economic and Demographic Profile; Economic Development Preparedness Assessment; Target Market Analysis with Recommended Industry Targets; and a Marketing Plan. Plans were completed for 10 cities and work continues with the implementation process. City officials and ElectriCities staff will focus on an additional 10 cities for the coming year.

Successful negotiations resulted in Smithfield Packaging expanding operations in Kinston, which will bring 206 new jobs and an $80 million investment to the community. Other announcements include: Prettl Noma in Washington with 84 jobs and $10 million investment; Home Depot in Rocky Mount with 100 jobs and $10 million investment; and Carolina Classic in Edenton with 5 jobs and $8 million investment.

Advertising for the year was focused on the following segments: Automotive; Pharmaceutical/Medical Instruments; Electronics; Biotechnology; Rubber; Plastics; and Fabricated Metals. Approximately 269 inquiries were made that resulted in 10 site visits within the cities and towns.

## Marketing

NCEMPA marketing programs include innovative rates, educational workshops and energy-related services provided through the Energy Solutions Partner (ESP) program. Workshops are used to educate industrial and commercial customers about the benefits of energy efficiency and to train attendees in specific areas of energy conservation. Energy audits are available to help customers identify money saving projects at their facilities. The ESP program connects workshop attendees and energy audit recipients with their local energy provider and an alliance partner. Together they are capable of providing valuable turnkey energy savings projects. Alliance partnerships in the ESP program allow cities to partner with the best and the brightest in the energy fields to help meet the customers' needs. Cities also enhanced their economic development proposals by working through the ESP program to offer programs such as back-up generation, lighting, power quality surveys, demand control services, HVAC solutions and overall energy management systems.

NCEMPA staff and city representatives continue to work closely with commercial and industrial customers to maximize the value of their energy dollars and reduce power costs. ESP solutions include load side generation, demand controllers for load management, turnkey lighting services, power quality services, energy management systems and affordable training workshops. The ESP program sold over $4.5M in products and services during 2004.

Also in 2004, NCEMPA took an active role in working with the healthcare industry. Several hospitals and long-term care facilities are located throughout our members' communities and they play a vital role in the welfare of the communities. In an effort to work with this group of customers, NCEMPA held a workshop on back-up generation at healthcare facilities, which was promoted jointly by NCEMPA and the North Carolina Hospital Association. Continuing to place importance on key accounts, ElectriCities offered APPA's Key Accounts Certificate Program for the second year in a row. This time it was held in Wilmington, North Carolina in May 2004. The fast-track program consists of three courses, along with an oral and a written exam. Class participants were required to file a key accounts business plan and a customer marketing plan to complete the requirements for certification.

Last year, at the request of several member cities, a new team of ElectriCities employees was assembled to develop programs and services to help cities address the needs of residential customers. The team, named HEAT (the Home Energy Assistance Team) developed a comprehensive array of programs and services to enable residential customers to save money on electric bills and conserve energy.

Some of the initiatives resulting from HEAT's efforts were: energy education programs, including Understanding Energy Use Workshops; communication programs such as the weatherization video distributed in December; new Energy Auditor Training; and customized Customer Service Training.

ElectriCities staff also assisted the State Energy Office to help minimize state utility costs. In response to a request from Governor Mike Easley, all state electric accounts were reviewed for rate appropriateness. ElectriCities staff provided State Energy Office staff with current rate structures and utility billing records of state accounts with ElectriCities members.

## Field Services and Programs

During 2004, NCEMPA staff provided over 30 commercial and industrial audits to assist the members' retail customers in reducing power costs while increasing energy efficiency. NCEMPA staff also provided audit assistance in such areas as power quality, lighting, HVAC, compressed air, infrared scans and demand-side management.

## Retail Rates and Billing Services

Many NCEMPA participants request assistance in the analysis, review and revision of retail rates, as well as wholesale impact studies. In 2004, 24 retail studies were completed for 15 members, and wholesale power cost studies were prepared for eight members. In addition, 18 members received assistance in the development or revision of innovative and economic development rates for new or expanding customers who wished to implement demand control programs to reduce power costs. More than 30 competitive rate proposals were developed and 10 of those were successful in securing the load.

The Retail Billing Program serves 26 municipalities in gathering interval meter data for 250 commercial and industrial customers in those towns and cities. Cumbersome manual meter reading is unnecessary since NCEMPA staff remotely reads each meter in the office in a matter of minutes. Reports and graphs are customized for each participant and e-mailed within days of month-end. In some cases, as many as 40 customers are read and reported for one participant, saving that participant's billing staff many hours of information gathering. Upon request from the participant, customers are provided with an array of detailed data, which helps the customer to develop energy-saving programs and maximize NCEMPA's load management services. Particular attention is paid to customers with generation to ensure that those generators are operating properly. When a generator fails to run as required, NCEMPA staff works with the customer to restore functionality. Historical customer data is consistently provided in support of retail rate studies and is an invaluable tool in helping our municipalities offer the most competitive rates to their customers.

## Plant Status

**Mayo Unit 1 & Roxboro Unit 4** concluded 2004 with commendable performance statistics. Roxboro Unit 4 achieved a total of 639 consecutive days on-line operation, with a Capacity Factor of 67.5 percent against a target for the year of 46.9 percent. Roxboro's Equivalent forced outage rate was 1.85 against a target of 1.35. Mayo ended 2004 with 257 consecutive days on line. Mayo's 2004 Equivalent forced outage rate was 0.63 against a target of 1.3 and a Capacity Factor of 73.93 percent against a target of 46.3 percent.

**Brunswick Unit 1 & Unit 2** hit another record for MWh of generation since the plant began operation. In 2004, Brunswick Units 1 & 2 had combined generation of over 14.8 million MWh, exceeding the 14.7 million MWh generated in 2003. The Brunswick Nuclear Plant achieved another industry first with the completion of Unit 1's Extended Power Uprate: establishing a new capability rating of 935 MW, a 20 percent Extended Power Uprate, a first in the industry for a Boiling Water Reactor (BWR). The Brunswick Plant was honored in October 2004 by GE Energy for having two of the world's top sustained generation boiling water reactors included in GE's 2003 BWR Honor Roll. To be included in the honor roll, a plant's sustained generation must be in the top 25 percent of the world's 89 eligible BWR plants. Brunswick Unit 1's Capacity Factor for 2004 was 92.54 percent and Brunswick Unit 2's Capacity Factor for 2004 was 98.12 percent.

In October 2004, PEC submitted a license renewal application to the Nuclear Regulatory Commission requesting a 20-year operating license renewal for the Brunswick Nuclear Plant. The current 40-year operating license for Brunswick Unit 1 expires September 8, 2016 and Unit 2 expires December 27, 2014.

**Harris Nuclear Plant** generated over 7 million MWh and reached another milestone by generating a cumulative 113 million MWh since the unit was brought into service. The Plant has logged over 7.7 million man-hours without a lost-time accident. Harris went into an outage on May 6 that lasted 13 days. Prior to the outage, the plant had provided 261 days of continuous service, with a 2004 Capacity Factor of 88.65 percent. The unit was shutdown for refueling on October 15 and returned to service on November 17, 2004.

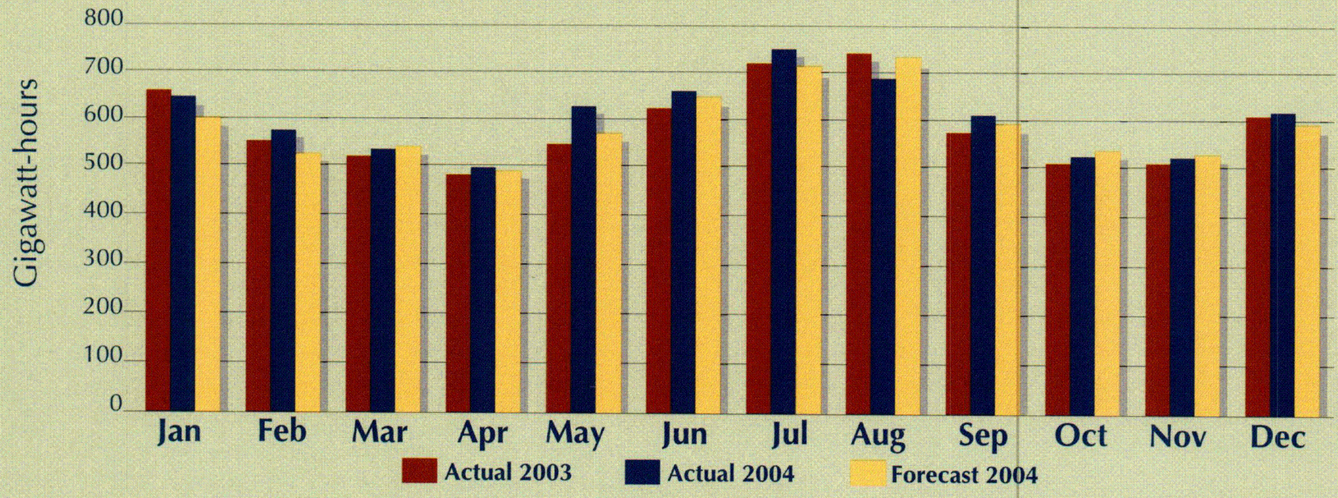
## Security

Immediately after the events of September 11, 2001, security at every nuclear power plant was placed on its highest level. Nuclear plant security now is consistent with Homeland Security threat levels. As a result, access to the plants is more strictly controlled; the defensive perimeters have been extended and reinforced and security forces and capabilities have been augmented. Under contractual arrangements with both NCMPA1 and NCEMPA, all issues of security are handled by Duke and PEC; coordinating closely with federal, state and local threat response authorities, law enforcement, the intelligence community and military. These and many other layers of protection provide an effective deterrence against potential safety or security problems related to terrorist activities and ensure safety and security at all the nuclear facilities in which NCMPA1 and NCEMPA have ownership.

# NCEMPA OPERATIONAL HIGHLIGHTS

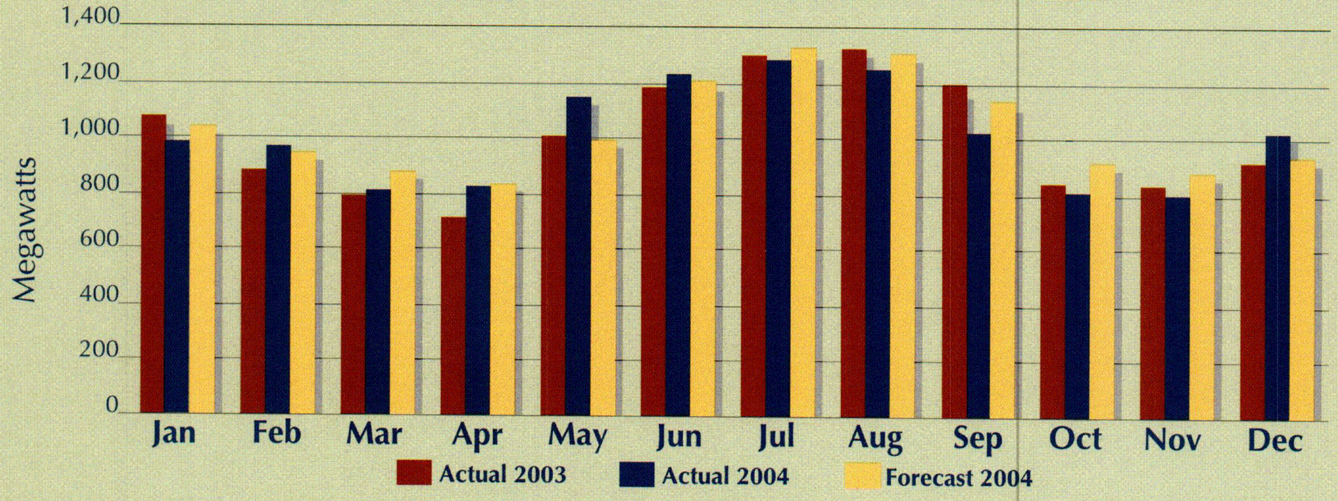
## NCEMPA Participant Energy Usage

(Billing Point Including SEPA; Forecast Year 2004 is from the 2003 Load Forecast)

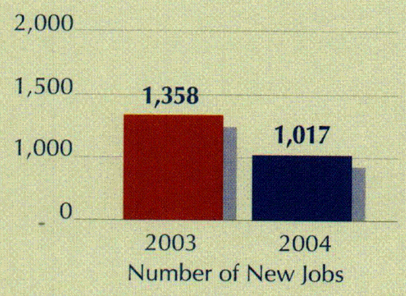


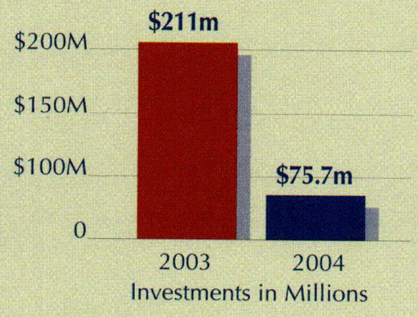

## NCEMPA Participant CP Demand

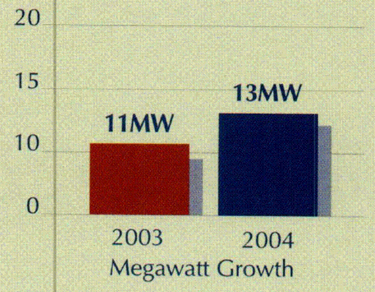
(Billing Point Including SEPA; Forecast Year 2004 is from the 2003 Load Forecast)




## NCEMPA Economic Development



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## Investment Portfolio Statistics

**Earnings***

| | Income | Rate of return |
|---|---|---|
| 2004 | $21,465,000 | 4.23% |
| 2003 | $20,891,000 | 4.23% |

**Market value as of 12/31***

| | Value | Average Maturity |
|---|---|---|
| 2004 | $623,657,000 | 6.5 years |
| 2003 | $627,798,000 | 4.6 years |

**Transactions**

| | Number | Amount |
|---|---|---|
| 2004 | 364 | $5,207,317,000 |
| 2003 | 439 | $6,189,269,000 |

## Debt Outstanding

**Debt outstanding 12/31**

| | Balance | Weighted Average Interest Cost |
|---|---|---|
| **Fixed Rate Bonds** | | |
| 2004 | $2,972,539,000** | 5.51% |
| 2003 | $3,056,816,000** | 5.60% |

## NCEMPA Bond Reconciliation

| | | |
|---|---|---|
| **Bonds Outstanding** | | |
| 12/31/03 | $ | 3,056,816,000** |
| Issued Series 2004 A & B | | 222,975,000 |
| **Matured** | | |
| 1/1/2004 | | 84,247,000 |
| Refunded | | 223,005,000 |
| **Bonds Outstanding** | | |
| 12/31/04 | $ | 2,972,539,000** |

## NCEMPA Bonds Outstanding

| Series | | Par Amount |
|---|---|---|
| Series 1986A | $ | 4,495,000 |
| Series 1989A | $ | 28,890,000 |
| Series 1991A | $ | 30,284,000 |
| Series 1993B | $ | 1,070,425,000 |
| Series 1993C | $ | 108,610,000 |
| Series 1995A | $ | 14,090,000 |
| Series 1996A | $ | 215,945,000 |
| Series 1996B | $ | 136,875,000 |
| Series 1997A | $ | 29,185,000 |
| Series 1999A | $ | 155,000,000 |
| Series 1999B | $ | 116,725,000 |
| Series 1999C | $ | 2,945,000 |
| Series 1999D | $ | 130,970,000 |
| Series 2003A | $ | 171,760,000 |
| Series 2003B | $ | 9,860,000 |
| Series 2003C | $ | 111,655,000 |
| Series 2003D | $ | 292,920,000 |
| Series 2003E | $ | 24,345,000 |
| Series 2003F | $ | 87,715,000 |
| Series 2003G | $ | 6,820,000 |
| Series 2004A | $ | 205,650,000 |
| Series 2004B | $ | 17,325,000 |

* For earnings and market value, amounts include income from and market value of securities held in the decommissioning trust.

** Does not include $1,009,000 for 2004 and $953,000 for 2003 respectively, accrued on the balance sheet for current maturities of the Series 1991A Capital Appreciation Bonds.

# NCEMPA INDEPENDENT AUDITORS' REPORT

The Board of Directors
North Carolina Eastern Municipal Power Agency
Raleigh, North Carolina

We have audited the accompanying balance sheets of North Carolina Eastern Municipal Power Agency as of December 31, 2004 and 2003, and the related statements of revenues and expenses and changes in fund equity, and cash flows for the years then ended. 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 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 North Carolina Eastern Municipal Power Agency as of December 31, 2004 and 2003, and the changes in financial position and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

The Management's Discussion and Analysis section listed in the table of contents is not a required part of the financial statements but is supplementary information required by the Governmental Accounting Standards Board. 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 this information and express no opinion thereon.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The other financial information as listed in the table of contents as of and for the years ended December 31, 2004 and 2003 is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in our audits of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Cherry, Bekaert & Holland, L.L.P.

Raleigh, North Carolina
April 11, 2005

## Management's Discussion and Analysis (MD&A)

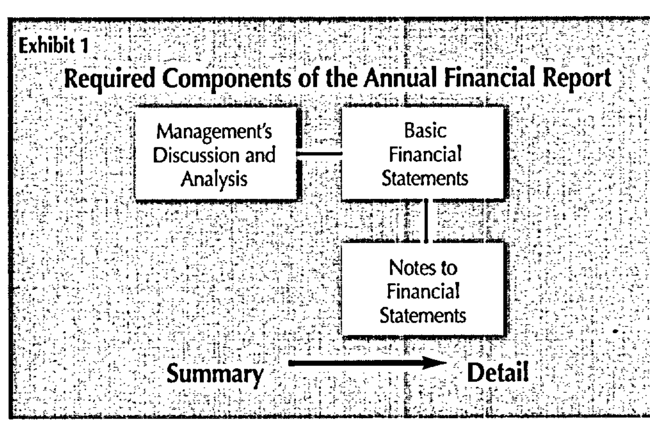
As management of North Carolina Eastern Municipal Power Agency (the Agency), we offer this narrative overview and analysis of the financial activities of the Agency for the year ended December 31, 2004 and 2003. We encourage you to read this information in conjunction with the information furnished in the Agency's financial statements that follow this narrative.

### Financial Highlights

- The Agency's basic financial statements consist of a single electric enterprise fund.
- At year-end 2004 and 2003, the Agency's assets exceeded its liabilities by $15,714,000 and $16,736,000, respectively (fund equity).
- The Agency's fund equity decreased by $1,022,000 and increased by $5,643,000 for 2004 and 2003, respectively.
- Year-end 2004 and 2003 unrestricted fund equity was $834,544,000 and $824,661,000, respectively, and increased $9,883,000 and $17,345,000 during 2004 and 2003, respectively.
- The Agency's total debt decreased $84,221,000 and $90,917,000 during 2004 and 2003, respectively.
  - Decreased $85,200,000 and $82,695,000 due to principal paid January 1, 2004 and 2003, respectively, in accordance with debt service schedules.
  - Decreased $30,000 and $9,175,000 due to equity contributions to facilitate the debt refunding issues in 2004 and 2003, respectively.
  - Increased $1,009,000 and $953,000 to reflect the appreciated value of the Capital Appreciation Bonds due January 1, 2005 and 2004, respectively.
- In May 2004, May 2003 and January 2003, the Agency refinanced some of its existing debt to take advantage of historically low interest rates.
  - In May 2004, the Agency issued $222,975,000 of Series 2004 A and B Refunding Bonds to refund $223,005,000 of previously issued bonds. Net present value savings realized were $21,094,000 with debt service savings ranging from $2,181,000 to $3,416,000 per year through 2019 and $339,000 and $230,000 in 2020 and 2021, respectively.
  - In May 2003, the Agency issued $412,685,000 of Series 2003 D, E, F, and G Bonds to refund $417,155,000 of previously issued bonds. Net present value savings realized were $21,530,000 with debt service reductions of approximately $2,650,000 per year through 2013 and smaller variable savings per year from 2014 to 2025.
  - In January 2003, the Agency issued $294,540,000 of Series 2003 A, B, and C Bonds to refund $299,245,000 of previously issued bonds. Net present value savings realized were $19,700,000 with debt service reductions of approximately $3,400,000 per year through 2011 and approximately $1,200,000 per year from 2012 to 2016.
- In conjunction with the Agency's bond offerings, the bond ratings remained the same or improved as follows:
  - Standard and Poor's – Unchanged at BBB (stable).
  - Moody's – From Baa3 (stable) to Baa3 (positive) in January 2003 and from Baa3 (positive) to Baa2 (stable) in May 2004.
  - Fitch – Unchanged at BBB+ (stable) throughout the two year period.
- The Agency implemented an average rate increase of 3% effective January 1, 2003 through the energy adjustment rider. On July 1, 2003, the energy adjustment rider was discontinued and a 3% rate increase was implemented. On October 1, 2003 a 1.2% rate increase was implemented through the energy adjustment rider. On March 1, 2004, the energy adjustment rider was discontinued and a 1.2% rate increase was implemented.
- In 2003, the Agency received $10,050,000 from the counterparty to the swaps for shortening the end dates.

## Overview of the Financial Statements

This MD&A is an introduction to the Agency's basic financial statements and notes to the financial statements (see Exhibit 1). In addition to the basic financial statements, this report



contains other supplemental information designed to enhance your understanding of the financial condition of the Agency.

## Basic Financial Statements

The Agency is a special purpose government that accounts for its activities as a business type entity. The first statements of the basic financial statements are for the Agency's single proprietary fund that focuses on the business activities of the electric enterprise. The statements are designed to provide a broad overview of the Agency's finances, similar in format to private sector business statements, and provide short and long-term information about the Agency's financial status, operations and cash flow. The statements report fund equity and how it has changed during the period. Fund equity is the difference between total assets and total liabilities. Analyzing the various components of fund equity is one way to gauge the Agency's financial condition.

The second section of the basic financial statements is the notes that explain in more detail some of the data contained in the basic financial statements. The notes provide additional information that is essential to a full understanding of the data provided in the basic financial statements. The notes are on pages 70 to 84 of this report.

After the notes, supplemental information is provided to show how the Agency's rates recovered its expenses as defined by the Bond Resolution, to show the Agency's performance against budget and to show activities in the special funds established by the Bond Resolution. Supplemental information can be found on pages 85 to 87 of this report.

## Financial Analysis

The electric enterprise fund financial statements for the years ended December 31, 2004 and 2003 are presented in accordance the Governmental Accounting Standards Board (GASB) Statement 34.

The various components of fund equity may serve over time as a useful indicator of the Agency's financial condition. The assets of the Agency exceeded liabilities by $15,714,000, $16,736,000, and $11,093,000 at December 31, 2004, 2003 and 2002, respectively, representing a decrease of $1,022,000 and an increase of $5,643,000 for 2004 and 2003, respectively.

The deficit portion of fund equity of $(911,384,000), $(915,757,000) and $(942,380,000) at December 31, 2004, 2003 and 2002, respectively, reflects the Agency's investments in capital assets (e.g. land, buildings, generation facilities, nuclear fuel and equipment), less any related debt outstanding that was issued to acquire or refinance those items. The deficit occurs because depreciation is expensed on a straight line basis over the life of the plant while debt repayment is structured similar to a home mortgage where early debt payments include more interest than principal and later payments include more principal than interest. This deficit was reduced during 2004 and 2003 due to the payment of principal debt service on January 1, equity contributions to facilitate the refunding of debt and the payment of capital additions from current operating funds, net of depreciation expense.

These capital assets are used to provide electric power to Agency Participants. Consequently, these assets are not available for future spending. While the Agency's investments in capital assets are reported net of the outstanding related debt, the resources needed to repay that debt will be provided through rates and certain reserve funds since the capital assets cannot be used to liquidate the liabilities.

**Exhibit 2** **Fund Equity**

| ($000s) | December 31, 2004 | 2003 | 2002 |
|---|---|---|---|
| Assets | | | |
| Capital assets | $ 726,496 | $ 766,246 | $ 777,707 |
| Current and other assets | 2,578,297 | 2,623,329 | 2,565,365 |
| Total assets | 3,304,793 | 3,389,575 | 3,343,072 |
| Liabilities | | | |
| Long-term liabilities outstanding | 3,175,774 | 3,262,145 | 3,220,637 |
| Other liabilities | 113,305 | 110,694 | 111,342 |
| Total liabilities | 3,289,079 | 3,372,839 | 3,331,979 |
| Fund Equity | | | |
| Invested in capital assets, net of related debt (deficit) | (911,384) | (915,757) | (942,380) |
| Restricted for debt service | 92,554 | 107,832 | 140,250 |
| Restricted for decommissioning | | | 5,907 |
| Unrestricted | 834,544 | 824,661 | 807,316 |
| Total fund equity | $ 15,714 | $ 16,736 | $ 11,093 |

An additional portion of the Agency's fund equity of $92,554,000, $107,832,000 and $140,250,000 at December 31, 2004 and 2003 and 2002, respectively, represents resources that are restricted for the payment of debt service.

An additional portion of the Agency's fund equity of $-0-, $-0- and $5,907,000 at December 31, 2004, 2003 and 2002, respectively, represents resources that are restricted for the payment of the Agency's asset retirement obligation (decommissioning of the nuclear units). The adoption of Statement of Financial Accounting Standard (SFAS) No. 143, "Accounting for Asset Retirement Obligations" resulted in deficit amounts in 2004 and 2003 and these deficits have been reclassified to unrestricted net assets. The recognition of the asset retirement obligation is on a straight-line basis over the life of the plant while funding of the decommissioning trust takes into account the interest earnings on the moneys deposited into the fund.

The remaining balance of $834,544,000, $824,661,000 and $807,316,000 at December 31, 2004 and 2003 and 2002, respectively, is unrestricted fund equity.

Several particular aspects of the Agency's financial operations increased unrestricted fund equity. These are as follows:

- Other revenues increased as a result of the benefits received from changing the end dates on the swap agreements.
- Revenues increased as a result of rate increases instituted.

### Budgetary Highlights

- No budget amendments were passed during 2004. In March 2005, a budget amendment was approved once all year-end accruals were known because total expenses had exceeded budget by $1,641,000. The primary reason for the overrun was due to higher fossil fuel costs due to higher rates and greater output from the fossil units. For 2003, no amendments were necessary.
- The Agency implemented an average rate increase of 3% effective January 1, 2003 through the energy adjustment rider. On July 1, 2003, the energy adjustment rider was discontinued and a 3% rate increase was implemented. On October 1, 2003 a 1.2% rate increase was implemented through the energy adjustment rider. On March 1, 2004, the energy adjustment rider was discontinued and a 1.2% rate increase was implemented.
- Debt service savings were realized as a result of the bond refunding issues completed.

## Capital Assets and Debt Administration

### Capital Assets

Investments in capital assets at December 31, 2004, 2003 and 2002 totaled $726,496,000, $766,246,000 and $777,707,000, respectively, (net of accumulated amortization and depreciation) for a decrease of $39,750,000 and $11,461,000 in 2004 and 2003, respectively. These assets include land, buildings, generation facilities, nuclear fuel and equipment.

**Exhibit 3**

**Changes in Fund Equity**

**($000s)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| **Revenues:** | | | |
| Operating revenues | $ 535,033 | $ 521,745 | $ 500,338 |
| Nonoperating revenues | 21,413 | (12,559) | 61,202 |
| Total Revenues | 556,446 | 509,186 | 561,540 |
| **Expenses:** | | | |
| Operating expenses | 344,947 | 319,828 | 312,853 |
| Interest on long-term debt | 161,450 | 166,783 | 178,576 |
| Other nonoperating expenses | 51,071 | 16,932 | 82,342 |
| Total Expenses | 557,468 | 503,543 | 573,771 |
| Increase (decrease) in fund equity | (1,022) | 5,643 | (12,231) |
| Fund equity January 1 | 16,736 | 11,093 | 23,324 |
| Fund equity December 31 | $ 15,714 | $ 16,736 | $ 11,093 |

Major capital asset transactions during 2004 and 2003 include the following:

- The primary reason for the decrease in capital assets is that depreciation and amortization were greater than plant and nuclear fuel additions.
- Construction Work in Progress (CWIP) increased $11,361,000 and $16,160,000 in 2004 and 2003, respectively, due to capital additions projects at the joint units.
- EPIS increased and CWIP decreased $17,501,000 and $13,225,000 in 2004 and 2003, respectively, due to the transfer of completed capital additions projects.
- In 2003, electric plant in service (EPIS) increased $59,606,000 and accumulated depreciation increased $32,675,000 due to the asset retirement obligation adjustment January 1, 2003 in accordance with Statement of Financial Accounting Standard No. 143, "Accounting for Asset Retirement Obligations."

**Exhibit 4**

## Capital Assets
**($000s)**

### Electric Utility Plant, Net

| | December 31, 2003 | Additions | Transfers | Retirements | December 31, 2004 |
|---|---|---|---|---|---|
| Electric Utility Plant | | | | | |
| Electric Plant in Service | $ 1,525,272 | $ 815 | $ 17,501 | $ (11,249) | $ 1,532,339 |
| Nuclear Fuel | 59,072 | 15,538 | | (9,356) | 65,254 |
| Total Electric Utility Plant | 1,584,344 | 16,353 | 17,501 | (20,605) | 1,597,593 |
| Accumulated Depreciation and Amortization | | | | | |
| Electric Plant in Service | (811,439) | (54,998) | | 11,249 | (855,188) |
| Nuclear Fuel | (33,122) | (16,217) | | 13,120 | (36,219) |
| Total Accumulated Depreciation and Amortization | (844,561) | (71,215) | - | 24,369 | (891,407) |
| Total Depreciable Electric Utility Plant (Net) | 739,783 | (54,862) | 17,501 | 3,764 | 706,186 |
| Land and Other Non-Depreciable Assets | | | | | |
| Land | 14,188 | (10) | | | 14,178 |
| Construction Work In Progress | 10,672 | 11,361 | (17,501) | | 4,532 |
| Total Electric Utility Plant (Net) | $ 764,643 | $ (43,511) | $ - | $ 3,764 | $ 724,896 |

| | December 31, 2002 | Additions | Transfers | Retirements | December 31, 2003 |
|---|---|---|---|---|---|
| Electric Utility Plant | | | | | |
| Electric Plant in Service | $ 1,454,980 | $ 59,945 | $ 13,225 | $ (2,878) | $ 1,525,272 |
| Nuclear Fuel | 60,794 | 13,588 | | (15,310) | 59,072 |
| Total Electric Utility Plant | 1,515,774 | 73,533 | 13,225 | (18,188) | 1,584,344 |
| Accumulated Depreciation and Amortization | | | | | |
| Electric Plant in Service | (726,108) | (88,209) | | 2,878 | (811,439) |
| Nuclear Fuel | (35,549) | (16,557) | | 18,984 | (33,122) |
| Total Accumulated Depreciation and Amortization | (761,657) | (104,766) | - | 21,862 | (844,561) |
| Total Depreciable Electric Utility Plant (Net) | 754,117 | (31,233) | 13,225 | 3,674 | 739,783 |
| Land and Other Non-Depreciable Assets | | | | | |
| Land | 14,180 | 8 | | | 14,188 |
| Construction Work In Progress | 7,737 | 16,160 | (13,225) | | 10,672 |
| Total Electric Utility Plant (Net) | $ 776,034 | $ (15,065) | $ - | $ 3,674 | $ 764,643 |

Exhibit 4

**Capital Assets**
**($000s)**

| Non-Utility Plant and Equipment, Net | December 31, 2003 | Additions | Transfers | Retirements | December 31, 2004 |
|---|---|---|---|---|---|
| Property and Equipment | $ 1,930 | $ 54 | $ - | $ - | $ 1,984 |
| Accumulated Depreciation | (1,037) | (57) | | | (1,094) |
| Total Depreciable Non-Utility Property and Equipment, Net | 893 | (3) | - | - | 890 |
| Land | 710 | | | | 710 |
| Total Non-Utility Property and Equipment, Net | $ 1,603 | $ (3) | $ - | $ - | $ 1,600 |

| Non-Utility Plant and Equipment, Net | December 31, 2002 | Additions | Transfers | Retirements | December 31, 2003 |
|---|---|---|---|---|---|
| Property and Equipment | $ 1,972 | $ 10 | $ - | $ (52) | $ 1,930 |
| Accumulated Depreciation | (1,009) | (80) | | 52 | (1,037) |
| Total Depreciable Non-Utility Property and Equipment, Net | 963 | (70) | - | - | 893 |
| Land | 710 | | | | 710 |
| Total Non-Utility Property and Equipment, Net | $ 1,673 | $ (70) | $ - | $ - | $ 1,603 |

Additional information on capital assets can be found in Note C on page 75 of this report.

## Outstanding Debt

Total debt outstanding at December 31, 2004, 2003 and 2002 was $2,973,548,000, $3,057,769,000 and $3,148,686,000, respectively, all of which are revenue bonds. Total debt decreased by $84,221,000 (2.8%) and $90,917,000 (2.9%) during 2004 and 2003, respectively, due to the principal debt payments and the equity contributions to facilitate the refunding of bonds, net of the accretion on the Capital Appreciation Bonds.

In May 2004, May 2003 and January 2003, the Agency refinanced some of its existing debt to take advantage of historically low interest rates.

- In May 2004, the Agency issued $222,975,000 of Series 2004 A and B Refunding Bonds to refund $223,005,000 of previously issued bonds. Net present value savings realized were $21,094,000 with debt service savings of from $2,181,000 to $3,416,000 per year through 2019 and $339,000 and $230,000 in 2020 and 2021, respectively.
- In May 2003, the Agency issued $412,685,000 of Series 2003 D, E, F, and G Refunding Bonds to refund $417,155,000 of previously issued bonds. Net present value savings realized were $21,530,000 with debt service savings of approximately $2,650,000 per year through 2013 and smaller variable savings per year from 2014 to 2025.
- In January 2003, the Agency issued $294,540,000 of Series 2003 A, B and C Refunding Bonds to refund $299,245,000 of previously issued bonds. Net present value savings realized were $19,700,000 with debt service savings of approximately $3,400,000 per year through 2011 and approximately $1,200,000 per year from 2012 to 2016.

The Agency's bond ratings improved from Moody's Investor Service from Baa3 (stable) to Baa3 (positive) in January 2003 and to Baa2 (stable) in May 2004 in association with the refunding bond offering. Standard and Poor's Corporation and FitchRatings left the ratings unchanged throughout the two years at BBB (stable) and BBB+ (stable), respectively.

Additional information regarding the Agency's long-term debt can be found in Note G beginning on page 80 of this report.

## Economic Factors and Next Year's Budgets and Rates

### Economic Factors

The following key economic factors played a role in the 2005 budget.

- Over the past year, a continued modest economic recovery has improved demand for electricity. The loss of manufacturing facilities to overseas competitors has played itself out and has been fully accounted for in the forecasts. As the economy picked up over the past year, short-term economic indicators have improved. Key areas of growth affecting the load forecast include housing (residential demand) and high-tech industries.
- Increased fuel costs continue to drive production costs upward. Natural gas prices increased to the $6/MBTU to $7/MBTU level, and the forward markets suggest that this trend will remain in place. High natural gas prices are driven by the depletion of wells in the Gulf of Mexico and by the increase in the number of gas-fired generating units. Coal prices have also increased dramatically over the past year due to increasing transportation and mining costs, as well as increased demand for more expensive and cleaner burning low-sulfur coal. With coal and natural gas prices elevated, both on and off-peak electricity prices are expected to remain higher than historical averages.

### Budget Highlights for 2005

- Reflects a continued focus on reliable, cost effective power supply and Participant services.
- Implements a 1.0% wholesale rate increase effective March 1.
- The load forecast projects energy sales growing 2.1% during 2004 and annual coincident peak demand growing 2.0% per year.
- Collection through rates of $91,005,000 for debt principal due January 1, 2006.
- Anticipates capital additions at the joint units of approximately $9,800,000 for nuclear power up-rates, Clean Smokestacks compliance at the fossil units and nuclear license extensions.
- Scheduled outage at Brunswick Unit 2 for refueling.

## Requests for Information

This report is designed to provide an overview of the Agency's finances for those who are interested. Questions concerning any of the information found in this report or requests for additional information should be directed to the Chief Financial Officer, North Carolina Eastern Municipal Power Agency, P. O. Box 29513, Raleigh, NC 27626-0513.

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# NCEMPA BALANCE SHEETS

**($000s)**

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| **ASSETS** | | |
| Non-Current Assets | | |
| Capital Assets (Note C) | | |
| Electric Utility Plant, Net | | |
| Electric plant in service | $ 1,546,514 | $ 1,539,460 |
| Construction work in progress | 4,532 | 10,672 |
| Nuclear fuel | 65,254 | 59,072 |
| Less accumulated depreciation & amortization | (891,404) | (844,561) |
| Total Electric Utility Plant, Net | 724,896 | 764,643 |
| Non-Utility Property and Equipment, Net | | |
| Property and Equipment | 2,694 | 2,640 |
| Less accumulated depreciation | (1,094) | (1,037) |
| Total Non-Utility Property and Equipment, Net | 1,600 | 1,603 |
| Total Capital Assets | 726,496 | 766,246 |
| Restricted Assets | | |
| Special Funds Invested (Notes D and G): | | |
| Bond fund | 365,149 | 381,719 |
| Reserve and contingency fund | 22,543 | 20,346 |
| Decommissioning fund | 2,703 | 2,543 |
| Special reserve fund | - | 1,011 |
| Total Special Funds Invested | 390,395 | 405,619 |
| Trust for Decommissioning Costs (Notes D and G) | 141,964 | 126,659 |
| Total Restricted Assets | 532,359 | 532,278 |
| Other Assets | | |
| Unamortized debt issuance costs | 41,068 | 35,060 |
| VEPCO compensation payment (Note E) | 6,607 | 6,996 |
| Development costs | 4,732 | 5,002 |
| Costs of advance refundings of debt | 379,783 | 394,251 |
| Other Deferred Costs (Note F) | 1,458,608 | 1,480,968 |
| Total Other Assets | 1,890,798 | 1,922,277 |
| Total Non-Current Assets | 3,149,653 | 3,220,801 |
| Current Assets | | |
| Funds Invested (Notes D and G): | | |
| Revenue fund | 42,286 | 19,403 |
| Operating fund | 34,282 | 55,319 |
| Supplemental fund | 16,810 | 23,194 |
| Total Funds Invested | 93,378 | 97,916 |
| Participants accounts receivable | 42,161 | 37,896 |
| Fossil fuel inventory | 3,537 | 5,145 |
| Prepaid expenses | 16,064 | 16,169 |
| Derivative financial instruments (Note B) | - | 11,648 |
| Total Current Assets | 155,140 | 168,774 |
| Total Assets | $ 3,304,793 | $ 3,389,575 |

See accompanying notes to financial statement.

# NCEMPA BALANCE SHEETS

**($000s)**

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| **LIABILITIES AND FUND EQUITY** | | |
| Liabilities | | |
| Non-Current Liabilities | | |
| Long-Term Debt | | |
| Bonds payable | $ 2,882,543 | $ 2,972,569 |
| Less unamortized discount | (19,433) | ( 35,531) |
| Total Long-Term Debt | 2,863,110 | 2,937,038 |
| Asset Retirement Obligation | 157,922 | 184,172 |
| Deferred Revenues (Note F) | 63,737 | 55,735 |
| Commitments and Contingencies (Notes B and HJ) | - | - |
| Total Non-Current Liabilities | 3,084,769 | 3,176,945 |
| Current Liabilities | | |
| Operating Liabilities: | | |
| Accounts payable | 20,433 | 19,360 |
| Accrued taxes | 7,111 | 7,095 |
| Derivative financial instruments (Note B) | 10,023 | |
| Total Operating Liabilities | 37,567 | 26,455 |
| Special Funds Liabilities: | | |
| Construction payables | | |
| Current maturities of bonds (Note G) | 91,005 | 85,200 |
| Accrued interest on bonds | 75,738 | 84,239 |
| Total Special Funds Liabilities: | 166,743 | 169,439 |
| Total Current Liabilities | 204,310 | 195,894 |
| Total Liabilities | 3,289,079 | 3,372,839 |
| Fund Equity | | |
| Invested in capital assets, net of related debt (deficit) | (911,384) | ( 915,757) |
| Restricted for debt service | 92,554 | 107,832 |
| Unrestricted | 834,544 | 824,661 |
| Total fund equity | 15,714 | 16,736 |
| Total Liabilities and Fund Equity | $ 3,304,793 | $ 3,389,575 |

# NCEMPA STATEMENTS OF REVENUES AND EXPENSES AND CHANGES IN FUND EQUITY

**($000s)**

| | Years Ended December 31, | |
|---|---|---|
| | 2004 | 2003 |
| **Operating Revenues:** | | |
| Sales of electricity to participants | $ 495,873 | $ 475,989 |
| Sales of electricity to utilities | 39,101 | 35,639 |
| Other Revenues | 59 | 10,117 |
| Total Operating Revenues | 535,033 | 521,745 |
| **Operating Expenses:** | | |
| Operation and maintenance | 42,081 | 43,468 |
| Fuel | 44,595 | 42,212 |
| Power coordination services: | | |
| Purchased power | 115,899 | 100,890 |
| Transmission and distribution | 20,835 | 20,555 |
| Other | 330 | 492 |
| Total power coordination services | 137,064 | 121,937 |
| Administrative and general | 31,020 | 25,435 |
| Amounts in lieu of taxes | 3,405 | 3,484 |
| Gross receipts tax | 15,879 | 15,456 |
| Depreciation and amortization | 60,037 | 57,575 |
| Amortization of asset retirement obligation | 10,866 | 10,261 |
| Total Operating Expenses | 344,947 | 319,828 |
| Operating Income | 190,086 | 201,917 |
| **Nonoperating (Revenues) Expenses** | | |
| Investment income | (21,413) | (20,892) |
| Net decrease in fair value of investments and derivative financial instruments | 21,155 | 33,451 |
| Interest expense | 161,450 | 166,783 |
| Amortization of debt refunding cost | 36,423 | 36,660 |
| Amortization of debt discount and issuance costs | 247 | 933 |
| Net increase in other deferred costs (Note F) | (14,756) | (25,584) |
| Net increase in deferred revenues (Note F) | 8,002 | 4,923 |
| Total nonoperating expenses | 191,108 | 196,274 |
| Increase (Decrease) in Fund Equity | (1,022) | 5,643 |
| Fund Equity, Beginning of the Year | 16,736 | 11,093 |
| Fund Equity, End of the Year | $ 15,714 | $ 16,736 |

See accompanying notes to financial statement.

# NCEMPA STATEMENTS OF CASH FLOWS

**($000s)**

| | Years Ended December 31, 2004 | Years Ended December 31, 2003 |
|---|---|---|
| Cash Flows from Operating Activities: | | |
| Receipts from sales of electricity | $ 530,722 | $ 516,879 |
| Payments of operating expenses | (265,187) | (231,400) |
| Net cash provided by operating activities | 265,535 | 285,479 |
| Cash Flows from Capital and Related Financing Activities: | | |
| Bonds issued | 222,975 | 707,225 |
| Bonds refunded | (223,005) | (716,400) |
| Interest paid | (168,905) | (169,412) |
| Debt discount and issuance costs paid | (11,618) | 319 |
| Additions to electric utility plant and non-utility property and equipment | (26,159) | (37,542) |
| Bonds retired or redeemed | (85,200) | (82,695) |
| Net cash used for capital and related financing activities | (291,912) | (298,505) |
| Cash Flows from Investing Activities: | | |
| Sales and maturities of investment securities | 5,203,018 | 6,141,349 |
| Purchases of investment securities | (5,189,099) | (6,151,154) |
| Investment earnings receipts from non-construction funds | 12,458 | 22,831 |
| Net cash provided by investing activities | 26,377 | 13,026 |
| Net Change in Operating Cash | - | - |
| Operating Cash, Beginning of year | 2 | 2 |
| Operating Cash, End of year | $ 2 | $ 2 |

Reconciliation of Net Operating Income to Net Cash Provided by Operating Activities:

| | 2004 | 2003 |
|---|---|---|
| Net Operating Income | $ 190,086 | $ 201,917 |
| Adjustments: | | |
| Depreciation and amortization | 60,037 | 57,375 |
| Amortization of nuclear fuel | 16,216 | 16,557 |
| Changes in assets and liabilities: | | |
| (Increase) decrease in participant accounts receivable | (4,265) | 5,204 |
| Decrease in fossil fuel stock | 1,608 | 318 |
| Decrease in prepaid expenses | 105 | 363 |
| Decrease in deferred costs | 659 | 659 |
| Increase in accounts payable | 1,073 | 3,364 |
| Increase (decrease) in accrued taxes | 16 | (278) |
| Total Adjustments | 75,449 | 83,562 |
| Net Cash Provided by Operating Activities | $ 265,535 | $ 285,479 |

See accompanying notes to financial statements.

## A. GENERAL MATTERS

North Carolina Eastern Municipal Power Agency (Agency) is a joint agency organized and existing pursuant to Chapter 159B of the General Statutes of North Carolina to enable municipal electric systems, through the organization of the Agency, to finance, build, own and operate generation and transmission projects. The Agency is comprised of 32 municipal electric systems (Participants) with interests ranging from 0.0783% to 16.1343%, which receive power from the Agency.

### Initial Project

The initial project is comprised of the Agency's undivided ownership interests in three nuclear-fueled and two coal-fired generating units presently in commercial operation by Progress Energy Carolinas, Inc. (PEC). (See table on page 75 for a listing of the units and the Agency's ownership interest in each unit.) The initial project is financed under Power System Revenue Bond Resolution No. R-2-82 (Resolution) adopted by the Board of Commissioners (Board) of the Agency. The Resolution established special funds to hold proceeds from debt issuance, such proceeds to be used for costs of acquisition and construction of the initial project and to establish and maintain certain reserves. The Resolution also established special funds into which initial project revenues from Participants are to be deposited and from which initial project operating costs, debt service and other specified payments are to be made.

The Agency entered into several agreements with PEC that govern the purchase, ownership, construction, operation and maintenance of the generating units in the initial project. Under these agreements, PEC manages the construction and operation of the generating units in which the Agency has undivided ownership interests. Both PEC and the Agency have the right to challenge the allocation of charges for a period extending to April 1 of the second year after which the challenged payment or adjustment was made.

In 2002, the Agency and PEC finalized a contract for supplemental power purchases by the Agency from PEC from 2004 to 2009. Purchases under the new contract replaced purchases under the old contract and the Peaking Project Delay Agreement (discussed later) effective January 1, 2004.

The Agency also entered into agreements with PEC and Virginia Electric and Power Company (VEPCO) for the transmission of power to the Agency's Participants. The Power Coordination Agreement (1981 PCA) obligates PEC to purchase power from the Agency in specified percentages of the Agency's entitlement to such power from Harris Unit 1 (1987-2007).

The Agency entered into two power sales agreements with each of its Participants for supplying the total electric power requirements of the Participants in excess of Southeastern Power Administration (SEPA) allocations. With the power generated from the initial project, together with supplemental purchases of power from PEC, the Agency provides the total electric power requirements of its Participants, exclusive of power allotments from SEPA. Under the Initial Project Power Sales Agreements, the Agency sells to the Participants their respective shares of initial project output. The revenues received relative to the initial project are pledged as security for bonds issued under the Resolution, after payment of initial project operating expenses. Each Participant is obligated to pay its share of operating costs and debt service for the initial project. Under the Supplemental Power Sales Agreements, the Agency supplies each Participant the additional power it requires in excess of that provided by output from the initial project and from SEPA.

### Peaking Project Delay Agreement (Delay Agreement)

In 1996, the Agency entered into an agreement with PEC to delay the commercial operation of the Agency's peaking project (subsequently cancelled) until January 1, 2004. In return, PEC provided capacity and energy equal to the peaking project at a price comparable to what it would have cost to operate the peaking project during the delay period (June 1, 1998 to December 31, 2003). As mentioned previously, in 2002 the Agency and PEC entered into an agreement for the replacement of the power provided under the Delay Agreement for 2004 to 2009.

### ElectriCities of North Carolina

ElectriCities of North Carolina, Inc. (ElectriCities), organized as a joint municipal assistance Agency under the General Statutes of North Carolina, is a public body and body corporate and politic created for the purpose of providing aid and assistance to municipalities in connection with their electric systems and to joint agencies, such as the Agency.

The Agency entered into a management agreement with ElectriCities. Under the current management agreement with the Agency, ElectriCities is required to provide all personnel and personnel services necessary for the Agency to conduct its business in an economic and efficient manner. This agreement continues through December 31, 2007, and is automatically renewed for successive three-year periods unless terminated by one year's notice by either party prior to the end of the contract term.

For the years ended December 31, 2004 and 2003, the Agency paid ElectriCities $5,124,000 and $5,193,000, respectively.

## B. SIGNIFICANT ACCOUNTING POLICIES

### Basis of Accounting

The Accounts of the Agency are maintained on the accrual bassis, in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission, and are in conformity with accounting principles generally accepted in the United States of America (GAAP). The Agency has adopted the principles promulgated by the Governmental Accounting Standards Board (GASB) and Statement of Financial Accounting Standard (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended. This standard allows utilities to capitalize or defer certain costs and/or revenues based upon the Agency's ongoing assessment that it is probable that such items will be recovered through future revenues.

In 1999, GASB issued Statement No. 34, "Basic Financial Statements – and Management's Discussion and Analysis – for State and Local Governments" (GASB No. 34). The statement requires certain information be included in the financial statements and specifies how that information should be presented.

The financial statements are prepared using the economic resources measurement focus. Operating revenues are defined as revenues received from the sale of electricity and associated services. Revenues from capital and related financing activities and investment activities are defined as non-operating revenues. Restricted equity represents constraints on resources that are imposed by Resolution and may be utilized only for the purposes established by the Resolution. Unrestricted equity may be utilized for any purpose approved by the Board through the budget process. When both restricted and unrestricted equity might be used to meet an obligation, the Agency first uses the restricted equity.

### Financial Reporting

Under 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.

### Electric Plant in Service

All direct and indirect expenditures associated with the development and construction of the Agency's undivided ownership interests in five of PEC's generating units in commercial operation, including interest expense net of investment earnings on funds not yet expended, have been recorded at original cost (plus acquisition adjustment) and are being depreciated (or amortized) on a straight-line basis over the life of the debt issued to fund each unit's assets. At December 31, 2004, the remaining life of the debt used to fund the assets for Brunswick Units 1 and 2 was 5 years, Harris Unit 1 was 20 years, Roxboro Unit 4 was 10 years and Mayo Unit 1 was 12 years.

The asset retirement obligation adjustment arising from implementing SFAS No. 143 (discussed under Decommissioning Costs beginning on page 73) is also included. It is being depreciated over the remaining life of the plants from which the asset retirement obligation arises. At December 31, 2004, the remaining life for Brunswick Unit 1 was 11 years, 8 months; for Brunswick Unit 2 was 10 years and for Harris Unit 1 was 21 years, 6 months.

In November 2003, GASB issued Statement No. 42,"Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries". Under this statement, governments must report impairment of capital assets. GASB defines impairment as a significant, unexpected decline in the service utility of a capital asset. This statement also covers insurance recoveries, whether connected to a loss or not. The Agency will implement this statement for the year ending December 31, 2006. The Agency has not yet determined what, if any, impact it will have on the Agency's financial statements.

### Construction Work in Progress

All expenditures associated with capital additions related to the Agency's undivided ownership interests in PEC's generating units are capitalized as construction work in progress until such time as they are complete, at which time they are transferred to Electric Plant in Service. No interest is capitalized on capital additions. Depreciation expense is recognized on these items after they are transferred.

### Nuclear Fuel

All expenditures related to the purchase and construction of the Agency's undivided ownership interests in nuclear fuel cores are capitalized until such time as the cores are placed in the reactor. No interest is capitalized on fuel cores. Once placed in the reactor, they are amortized to fuel expense utilizing the units of production method. Amounts are removed from the books upon disposal of the spent nuclear fuel. Nuclear fuel expense includes a provision for estimated disposal costs, which is being collected currently from Participants. Amortization of nuclear fuel costs in 2004 and 2003 includes a provision of \$3,913,000 and \$3,889,000, respectively, for estimated disposal costs.

The Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the Department of Energy's (DOE) uranium enrichment plants. Nuclear plant licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. PEC makes the annual payment to DOE for the Brunswick and Harris units and bills the Agency for their proportionate share. The Agency's payments to PEC were approximately $793,000 and $776,000 in 2004 and 2003, respectively, and were recorded as fuel expense.

Under provisions of the Nuclear Waste Policy Act of 1982, PEC, on behalf of PEC and the Agency, entered into contracts with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent nuclear fuel in 1998, the year provided by the Nuclear Waste Policy Act and PEC's contract with the DOE. PEC, on behalf of all co-owners and along with other utilities, has taken steps to force the DOE to take spent nuclear-fuel. To date, the courts have rejected these attempts. In January 2004, PEC joined with other utilities in suing the DOE for not establishing a national repository by the deadline.

The Agency stores all spent fuel within its facilities. With certain modifications, the Agency's spent fuel storage facilities are sufficient to handle all spent fuel generated by all of the Agency's nuclear generating units through the expiration of their current operating licenses.

### Non-Utility Property and Equipment

All expenditures related to purchasing and installing an in-house computer, jointly owned with North Carolina Municipal Power Agency Number 1 (NCMPA1), have been capitalized and are fully depreciated. Also included are the land and administrative office building jointly owned with NCMPA1 and used by both agencies and ElectriCities. The administrative office building is being depreciated over 37½ years on a straight-line basis.

### Investments

The Agency has implemented the provisions of GASB Statement No. 31, "Accounting and Financial Reporting for Certain Investments and for External Investment Pools," which requires investments to be reported at fair value.

### Derivative Financial Instruments

The Agency reports in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Certain Hedging Activities" (SFAS No. 133) and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of SFAS 133" (SFAS No. 138). SFAS No. 133 and SFAS No. 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values.

The Agency has six interest rate swap agreements, none of which has been designated as a hedge. Two of the agreements are fixed to variable rate swaps and four are variable to fixed rate swaps. The four variable to fixed rate swaps were entered into in May 2004.

The following details the terms of the various swap agreements (dollars in thousands):

| Notional Amount | Fixed Rate | Variable Rate Index | Rate | December 31, 2004 Rate | Termination Date |
|---|---|---|---|---|---|
| **Fixed to Variable Rate Swaps** | | | | | |
| $ 155,000 | 4.67% | BMA Municipal Swap | Index | 1.990% | March 1, 2005 |
| 136,970 | 5.03% | BMA Municipal Swap | Index | 1.990% | March 1, 2005 |
| **Variable to Fixed Rate Swaps** | | | | | |
| $ 79,975a | 3.655% | USD-LIBOR-BBA | 65.90% of index plus 0.25% | 1.832% | January 1, 2019 |
| 73,550b | 3.651% | USD-LIBOR-BBA | 65.90% of index plus 0.25% | 1.790% | January 1, 2019 |
| 17,325c | 5.090% e | USD-LIBOR-BBA | Index | 2.400% | January 1, 2021 |
| 52,125d | 3.644% | USD-LIBOR-BBA | 65.90% of index plus 0.25% | 1.832% | January 1, 2020 |

a - Reduces to $79,950 at 12/15/05, $79,925 at 11/30/06, $79,900 at 12/4/08, $79,850 at 12/9/10, $79,800 at 12/13/12 $62,925 at 12/18/14 and $61,925 at 12/3/15.

b - Reduces to $73,525 at 12/26/13, $56,900 at 12/31/15 and $56,875 at 12/28/17.

c - Reduces to $17,300 at 12/14/06, $17,275 at 12/11/08, $17,250 at 12/9/10, $17,200 at 12/6/12, $17,175 at 12/5/13 $5,550 at 12/27/18 and $300 at 12/26/19.

d - Reduces to $52,000 at 12/7/06, $51,850 at 12/11/08, $51,700 at 12/16/10, $51,550 at 12/1/11, $49,100 at 12/5/13 $46,675 at 12/26/14, $42,525 at 12/10/15, $27,250 at 12/29/16, $19,950 at 12/14/17 and $17,425 at 11/29/18.

e - Taxable

The fixed to variable rate swap agreements had original termination dates in 2009. In 2003, the Agency shortened the end dates of both swaps to March 1, 2005, resulting in a $10,050,000 payment by the counterparty to the Agency.

The fixed to variable interest rate swap agreements were entered into to synthetically convert a portion of the Agency's fixed rate debt to variable rate debt over the life of the swaps. The BMA Municipal Swap Index was 1.99% and 1.14% at December 31, 2004 and 2003, respectively. Interest paid and received under the swap agreements increases and decreases, respectively, interest expense. The net effect was to reduce interest expense $10,530,000 and $11,113,000 in 2004 and 2003, respectively.

The variable to fixed interest rate swap agreements were entered into to synthetically convert a portion of the Agency's variable rate debt to fixed rate debt over the life of the swaps. The USD-LIBOR-BBA Index was 2.34% and 2.40% for 7 day and one month instruments, respectively, at December 31, 2004. Interest paid and received under the swap agreements increases and decreases, respectively, interest expense. The net effect was to reduce interest expense $3,073,000 in 2004.

The fair value of the interest rate swap agreements was approximately $(10,023,000) and $11,648,000 at December 31, 2004 and 2003, respectively. The fair value is the amount that would be paid or received if the swap were terminated and may change as market interest rates change. Current market pricing models were used to estimate the fair value of the interest rate swap agreements. The fluctuation in the fair value of the interest rate swaps was a decrease of $21,671,000 in 2004 and a decrease of $22,221,000 inclusive of the $10,050,000 payment received to shorten the end date in 2003 and is included in "Increase (decrease) in fair value of investments and derivative financial instruments" in the statements of revenues and expenses.

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, is not subject to repayment risk. The Agency minimizes the credit or repayment risk 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.

**Accounts Receivable**

Accounts receivable consist of trade accounts receivable associated with the sale of electricity and are stated at cost. The Agency primarily sells to the Participants in the project and accordingly, management does not believe an allowance for doubtful accounts is required.

**Decommissioning Costs**

NRC regulations require that each licensee of a commercial nuclear power reactor furnish to the NRC certification of its financial capability to meet the costs of nuclear decommissioning at the end of the useful life of the licensee's facility. As a co-licensee of Brunswick Units 1 and 2 and Harris Unit 1, the Agency is subject to the NRC's financial capability regulations, and therefore has furnished certification of its financial capability to fund its share of the costs of decommissioning those units.

To satisfy the NRC's financial capability regulations, the Agency established an external trust fund (Decommissioning Trust) pursuant to a trust agreement with a bank. The Agency's certification requires that the Agency make annual deposits to the Decommissioning Trust which, together with the investment earnings and amounts previously on deposit in the trust, are anticipated to result in sufficient funds being held in the Decommissioning Trust at the expiration of the current operating licenses for the units (currently 2014 for Brunswick Unit 2, 2016 for Brunswick Unit 1, and 2026 for Harris Unit 1) to meet the Agency's share of decommissioning.

In October 2004, PEC submitted an application to extend the licenses of both Brunswick units by 20 years. An application to extend the operating license of Harris is expected to be filed in 2006.

Estimates of the future costs of decommissioning the units are based on the most recent site-specific study that was conducted on behalf of PEC in 2004. The Agency's portion of decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, is $65,116,000 for Brunswick Unit 1, $70,265,000 for Brunswick Unit 2 and $69,168,000 for Harris, all stated in 2004 dollars.

The Decommissioning Trust is irrevocable and funds may be withdrawn from the trust solely for the purpose of paying the Agency's share of the costs of nuclear decommissioning. Under the NRC regulations, the Decommissioning Trust is required to be segregated from Agency assets and outside the Agency's administrative control. The Agency is deemed to have incurred and paid decommissioning costs as amounts are deposited to the Decommissioning Trust. In addition to the Decommissioning Trust, certain reserve assets are anticipated to be available to satisfy the Agency's total decommissioning liability.

The Agency determined that it was necessary to fund decommissioning costs associated with the non-nuclear portion of the Brunswick plant that fell outside the NRC requirements. Therefore, it has made deposits to the Decommissioning Fund separate from the requirements for the Decommissioning Trust.

In 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). The Agency implemented SFAS No. 143 effective January 1, 2003 as it relates to decommissioning costs of Brunswick Unit 2, Brunswick Unit 1 and Harris to be incurred at the end of their operating licenses, 2014, 2016 and 2026, respectively.

SFAS No. 143 requires the Agency 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 assets and record a corresponding asset that will be depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Any such adjustments for changes in the estimated future cash flows will also be capitalized and amortized over the remaining life of the asset.

Changes in components of the asset retirement obligation during 2004 and 2003 are as follows (in thousands of dollars):

| | Years Ended December 31, | |
|---|---|---|
| | 2004 | 2003 |
| Balance, beginning of year | $ 184,172 | $ 173,981 |
| Liabilities incurred during the year | | |
| Liabilities settled during the year | | |
| Accretion expense | 10,866 | 10,261 |
| Revisions in estimated cash flows | (37,116) | |
| Balance, end of year | $ 157,922 | $ 184,172 |

### Fossil Fuel Inventory

Fossil fuel inventory includes fossil fuel stock and EPA Clean Air Act Allowances, each of which is stated at average cost.

refundings of debt at December 31, 2004 and 2003, shown net of accumulated amortization of $340,484,000 and $318,489,000, respectively, are deferred and amortized using the interest method over the term of the debt issued on refunding. Other deferred costs and deferred revenues are not amortized but will either be recovered from or refunded to Participants through future rates (see Note F).

### Discounts/Premiums on Bonds

Discounts on bonds (net of premiums) at December 31, 2004 and 2003 shown net of accumulated accretion/amortization of $(442,000) and $7,342,000, respectively, are amortized over the terms of the related bonds in a manner which yields a constant rate of interest.

### Taxes

Income of the Agency is excludable from income subject to federal income tax under Section 115 of the Internal Revenue Code. Chapter 159B of the General Statutes of North Carolina exempts the Agency from property and franchise or other privilege taxes. In lieu of property taxes, the Agency pays an amount that would otherwise be assessed on the real and personal property of the Agency. In lieu of a franchise or privilege tax, the Agency pays an amount equal to 3.22% of the gross receipts from sales of electricity to Participants.

### Statements of Cash Flows

For purposes of the statements of cash flows, operating cash consists of unrestricted cash of $2,000 at both December 31, 2004 and 2003, included on the balance sheet in the line item "Current Assets: Funds Invested". Restricted cash of $2,000 and $3,000, respectively, at December 31, 2004 and 2003, included on the balance sheet in the line item "Restricted Assets: Special Funds Invested" is not part of the statements of cash flows.

### Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures 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 2003 amounts have been reclassified to conform to 2004 classifications. The reclassifications had no effect on excess of revenues over expenses or retained earnings as previously reported.

## C. CAPITAL ASSETS

### Initial Project

The Agency has commitments to PEC in connection with capital additions for the initial project. Current estimates indicate the Agency's portion of these costs for 2005 and 2006 will be approximately $33,126,000.

The Agency's agreements with PEC specify the purchase of undivided ownership interests in nuclear-fueled and coal-fired generating units, which comprise the initial project, presently in commercial operation as follows:

On January 1, 2005, PEC increased the MNDC of Brunswick Unit 1 to 938 MW increasing the Agency's ownership share to 171.9 MW. In addition, in conjunction with Brunswick Unit 2's spring refueling outage, PEC expects to complete uprate work which will increase its MNDC to 928 MW thus increasing the Agency's ownership share to 170.1 MW.

### Electric Utility Plant, Net

Changes in components of electric utility plant, net during 2004 and 2003 are as follows (in thousands of dollars):

| | Commercial Operations | Maximum Net Dependable Capability (MNDC) | Agency Ownership | Agency Megawatts |
|---|---|---|---|---|
| | Coal-Fired Units | | | |
| Roxboro Unit 4 | 1980 | 700 MW | 12.94 % | 90.6 MW |
| Mayo Unit 1 | 1983 | 745 | 16.17 | 120.5 |
| Total Coal-Fired Capability | | | | 211.1 |
| | Nuclear-Fueled Units | | | |
| Brunswick Unit 2 | 1975 | 900 MW | 18.33 % | 165.0 |
| Brunswick Unit 1 | 1977 | 935 | 18.33 | 171.4 |
| Harris Unit 1 | 1987 | 900 | 16.17 | 145.5 |
| Total Nuclear-Fueled Capability | | | | 481.9 |
| Total of All Units | | | | 693.0 MW |

| | December 31, 2003 | Additions | Transfers | Retirements | December 31, 2004 |
|---|---|---|---|---|---|
| Electric Utility Plant | | | | | |
| Electric Plant in Service | $ 1,525,272 | $ 815 | $ 17,501 | $ (11,249) | $ 1,532,339 |
| Nuclear Fuel | 59,072 | 15,538 | | (9,356) | 65,254 |
| Total Electric Utility Plant | 1,584,344 | 16,353 | 17,501 | (20,605) | 1,597,593 |
| Accumulated Depreciation and Amortization | | | | | |
| Electric Plant in Service | (811,439) | (54,998) | | 11,249 | (855,188) |
| Nuclear Fuel | (33,122) | (16,217) | | 13,120 | (36,219) |
| Total Accumulated Depreciation and Amortization | (844,561) | (71,215) | - | 24,369 | (891,407) |
| Total Depreciable Electric Utility Plant (Net) | 739,783 | (54,862) | 17,501 | 3,764 | 706,186 |
| Land and Other Non-Depreciable Assets | | | | | |
| Land | 14,188 | (10) | | | 14,178 |
| Construction Work In Progress | 10,672 | 11,361 | (17,501) | | 4,532 |
| Total Electric Utility Plant (Net) | $ 764,643 | $ (43,511) | $ - | $ 3,674 | $ 724,896 |

| | December 31, 2002 | Additions | Transfers | Retirements | December 31, 2003 |
|---|---|---|---|---|---|
| Electric Utility Plant | | | | | |
| Electric Plant in Service | $ 1,454,980 | $ 59,945 | $ 13,225 | $ (2,878) | $ 1,525,272 |
| Nuclear Fuel | 60,794 | 13,588 | | (15,310) | 59,072 |
| Total Electric Utility Plant | 1,515,774 | 73,533 | 13,225 | (18,188) | 1,584,344 |
| Accumulated Depreciation and Amortization | | | | | |
| Electric Plant in Service | (726,108) | (88,209) | | 2,878 | (811,439) |
| Nuclear Fuel | (35,549) | (16,557) | | 18,984 | (33,122) |
| Total Accumulated Depreciation and Amortization | (761,657) | (104,766) | - | 21,862 | (844,561) |
| Total Depreciable Electric Utility Plant (Net) | 754,117 | (31,233) | 13,225 | 3,674 | 739,783 |
| Land and Other Non-Depreciable Assets | | | | | |
| Land | 14,180 | 8 | | | 14,188 |
| Construction Work In Progress | 7,737 | 16,160 | (13,225) | | 10,672 |
| Total Electric Utility Plant (Net) | $ 776,034 | $ (15,065) | $ - | $ 3,674 | $ 764,643 |

2003 additions for electric plant in service and accumulated depreciation include $56,606,000 and $32,675,000, respectively, representing the initial asset retirement obligation recorded by the Agency in accordance with SFAS No. 143.

**Non-Utility Property and Eaquipment, Net**

Changes in components of non-utility property and equipment, net during 2004 and 2003 are as follows (in thousands of dollars):

| | December 31, 2003 | Additions | Transfers | Retirements | December 31, 2004 |
|---|---|---|---|---|---|
| Property and Equipment | $ 1,930 | $ 54 | $ - | $ - | $ 1,984 |
| Accumulated Depreciation | (1,037) | (57) | | | (1,094) |
| Total Depreciable Non-Utility Property and Equipment, Net | 893 | (3) | - | - | 890 |
| Land | 710 | | | | 710 |
| Total Non-Utility Property and Equipment, Net | $ 1,603 | $ (3) | $ - | $ - | $ 1,600 |

| | December 31, 2002 | Additions | Transfers | Retirements | December 31, 2003 |
|---|---|---|---|---|---|
| Property and Equipment | $ 1,972 | $ 10 | $ - | $ (52) | $ 1,930 |
| Accumulated Depreciation | (1,009) | (80) | | 52 | (1,037) |
| Total Depreciable Non-Utility Property and Equipment, Net | 963 | (70) | - | - | 893 |
| Land | 710 | | | | 710 |
| Total Non-Utility Property and Equipment, Net | $ 1,673 | $ (70) | $ - | $ - | $ 1,603 |

## D. INVESTMENTS

The Resolution authorizes the Agency to invest in 1) direct obligations of, or obligations of which the principal and interest are unconditionally guaranteed by the United States (U.S.), 2) obligations of any Agency of the U.S. or corporation wholly owned by the U.S., 3) direct and general obligations of the State of North Carolina or any political subdivision thereof whose securities are rated "A" or better, 4) repurchase agreements with a member of the Federal Reserve System which are collateralized by previously described obligations and 5) bank time deposits evidenced by certificates of deposit and bankers' acceptances.

Bank time deposits may only be in banks with capital stock, surplus and undivided profits of $20,000,000 or $50,000,000 for North Carolina banks and out-of-state banks, respectively, and the Agency's investments deposited in such banks cannot exceed 50% and 25%, respectively, of such banks' capital stock, surplus and undivided profits.

The Resolution permits the Agency to establish official depositories with any bank or trust company qualified under the laws of North Carolina to receive deposits of public moneys and having capital stock, surplus and undivided profits aggregating in excess of $20,000,000.

All depositories must collateralize public deposits in excess of federal depository insurance coverage. The Agency's depositories use the pooling method, a single financial institution collateral pool. Under the pooling method, a depository establishes a single escrow account on behalf of all governmental agencies. Collateral is maintained with an eligible escrow agent in the name of the State Treasurer of North Carolina based on an approved averaging method for demand deposits and the actual current balance for time deposits less the applicable federal depository insurance for each depositor. The financial institutions using the pooling method are responsible for assuring sufficient collateralization of these excess deposits.

Because of the inability to measure the exact amount of collateral pledged for the Agency under the pooling method, the potential exists for under-collateralization. However, the State Treasurer enforces strict standards for each pooling method depository, which minimizes any risk of under-collateralization. At December 31, 2004 and 2003, the Agency had $4,000 and $5,000 covered by federal depository insurance.

The Agency's investments are categorized to give an indication of the level of risk assumed by the Agency at year-end. Category 1 includes investments that are insured or registered or for which the securities are held by the Agency or its agent in the Agency's name. Category 2 includes uninsured and unregistered investments for which the securities are held by the broker or dealer, or by its trust department or agent in the Agency's name. Category 3 includes uninsured and unregistered investments for which the securities are held by the broker or dealer, or by its safekeeping department or agent, but not in the Agency's name. All investments except repurchase agreements are considered Category 1. Repurchase agreements are considered Category 3.

The Agency's investments are detailed in the following schedule. (In thousands of dollars.)

| | December 31, | | | |
|---|---|---|---|---|
| | 2004 | | 2003 | |
| | Cost Basis | Fair Value | Cost Basis | Fair Value |
| Repurchase agreements | $ 246,980 | $ 246,981 | $ 103,965 | $ 103,965 |
| U.S. government agencies | 190,777 | 193,088 | 348,487 | 353,392 |
| Municipal bonds | | | 7,794 | 8,304 |
| Strips | 7,179 | 10,921 | 8,468 | 11,539 |
| Collateralized mortgage obligations | 31,060 | 30,756 | 24,764 | 23,940 |
| | 475,996 | 481,746 | 493,478 | 501,140 |
| Decommissioning Trust securities | 76,187 | 141,964 | 71,112 | 126,659 |
| Cash | | | | |
| Operating cash | 2 | 2 | 2 | 2 |
| Restricted cash | 2 | 2 | 3 | 3 |
| Accrued interest | 2,023 | 2,023 | 2,390 | 2,390 |
| Total funds invested | $ 554,210 | $ 625,737 | $ 566,985 | $ 630,194 |
| Consisting of: | | | | |
| Special funds invested | | $ 390,395 | | $ 405,619 |
| Decommissioning Trust | | 141,964 | | 126,659 |
| Operating assets | | 93,378 | | 97,916 |
| Total funds invested | | $ 625,737 | | $ 630,194 |

In accordance with the provisions of the Resolution, the collateral under the repurchase agreements is segregated and held by the trustee for the Agency.

The Agency's impaired investments are detailed in the following schedule (in thousands of dollars):

| | December 31, 2004 | | | | | |
|---|---|---|---|---|---|---|
| | Less Than 12 Months | | 12 Months or Longer | | Total | |
| | Fair Value | Unrealized Losses | Fair Value | Unrealized Losses | Fair Value | Unrealized Losses |
| Repurchase agreements | $ - | $ - | $ - | $ - | $ - | $ - |
| U.S. government securities | | | | | - | - |
| U.S. government agencies | 24,718 | 88 | 105,396 | 1,478 | 130,114 | 1,566 |
| Municipal bonds | | | | | - | - |
| Strips | | | | | - | - |
| Collateralized mortgage obligations | | | 34,545 | 372 | 34,545 | 372 |
| Sub-total | 24,718 | 88 | 139,941 | 1,850 | 164,659 | 1,938 |
| Decommissioning Trust securities | 1,646 | 16 | | | 1,646 | 16 |
| Total | $ 26,364 | $ 104 | $ 139,941 | $ 1,850 | $ 166,305 | $ 1,954 |

## E. VEPCO COMPENSATION PAYMENT

The VEPCO compensation payment represents compensation to VEPCO for early termination of service for those Participants previously served by VEPCO. This payment of $15,515,000 and the related capitalized interest of $33,000 were deferred and are being amortized on a straight-line basis over 40 years, the expected life of the initial project. The balance at December 31, 2004 and 2003 is net of accumulated amortization of $8,941,000 and $8,552,000, respectively.

## F. OTHER DEFERRED COSTS AND DEFERRED REVENUES

Rates for power billings to Participants are designed to cover the Agency's operating expenses, debt requirements and reserves as specified by the Resolution and power sales agreements. Straight-line depreciation and amortization are not considered in the cost of service calculation used to design rates. In addition, certain earnings on funds established in accordance with the Resolution are restricted to those funds and are not available for current operations.

The differences between debt principal maturities (adjusted for the effects of premiums, discounts and amortization of deferred gains and losses) and straight-line depreciation and amortization and in interest income recognition are recognized as other deferred costs. When total deferred items exceed principal debt service, other deferred costs increase. When principal debt service exceeds total deferred items, other deferred costs decrease.

Funds collected through rates for reserve accounts and restricted investment income are recognized as deferred revenues, thus increasing deferred revenues. When these funds are used to meet current expenses, deferred revenues decrease.

The Agency's present charges to the Participants are sufficient to recover all of the Agency's current annual costs of the Participants' bulk power needs. Each Participant is required under the power sales agreements to set its rates for its customers at levels sufficient to pay all costs of its electric utility system, including the Agency's charges for bulk power supply. All Participants have done so.

All rates must be approved by the Board of Commissioners. Rates are designed on an annual basis and are reviewed quarterly. If they are determined to be inadequate to cover the Agency's current annual costs, rates may be revised.

In accordance with SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144) the Agency will assess the recoverability of its long lived assets whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. During 2004 and 2003, the Agency determined that such an assessment was not necessary.

Other deferred costs include the following (in thousands of dollars):

| | Year Ended December 31, | | Inception to December 31, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| **Other Deferred Costs** | | | | |
| Deferred interest expense | $ 6 | $ 119 | $ 652,614 | $ 652,608 |
| Amortization of debt discount and issuance costs | 247 | 933 | 60,875 | 60,628 |
| Net (increase) decrease in fair value of investments and derivative financial instruments | 21,155 | 33,451 | (10,089) | (31,244) |
| Depreciation and amortization | 70,903 | 67,836 | 1,023,825 | 952,922 |
| Amortization of debt refunding costs | 36,423 | 36,660 | 518,454 | 482,031 |
| Participant billing offsets | (113,978) | (113,415) | (840,032) | (726,054) |
| Asset Retirement Obligation Adjustment | | | 7,875 | 44,991 |
| New project negotiation and Harris Plant litigation costs | | | 45,086 | 45,086 |
| Net Other Deferred Costs | $ 14,756 | $ 25,584 | $ 1,458,608 | $ 1,480,968 |

The amount for other deferred costs shown for inception to December 31, 2004 has been adjusted by $37,116,000 to reflect the new liability as a result of the new decommissioning studies for Brunswick and Harris.

Deferred revenues include the following (in thousands of dollars):

| | Year Ended December 31, | | Inception to December 31, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| **Deferred Revenues** | | | | |
| Net special funds withdrawals | $ (42) | $ (2,449) | $ (148,192) | $ (148,150) |
| Restricted investment income | 8,044 | 7,372 | 234,340 | 226,296 |
| Rate stabilization funds used for other than operations | | | (21,839) | (21,839) |
| Special funds valuations | | | (572) | (572) |
| Net Deferred Revenues | $ 8,002 | $ 4,923 | $ 63,737 | $ 55,735 |

## G. BONDS

The Agency has been authorized to issue Power System Revenue Bonds (bonds) in accordance with the terms, conditions and limitations of the Resolution. The total to be issued is to be sufficient to pay the costs of acquisition and construction of the project, as defined, and/or for other purposes set forth in the Resolution. Future refunding of bonds may result in the issuance of additional bonds.

The following shows bond activity during 2004 (in thousands of dollars):

| | |
|---|---|
| Bonds Outstanding at December 31, 2003 | $ 3,057,769 |
| Principal payments January 1, 2004 (Includes $953 in appreciated value for the 1991 A Capital Appreciation Serial Bonds.) | (85,200) |
| Transfer from Accrued Interest to Current Maturities of Bonds to reflect the appreciated value of the | |
| Series 1991 A Capital Appreciation Serial Bonds due January 1, 2005 | 1,009 |
| Bonds Issued | |
| Series 2004 A | 205,650 |
| Series 2004 B | 17,325 |
| Bonds Refunded | |
| Series 1991 A | (130,680) |
| Series 1993 C | (57,590) |
| Series 1993 D | (34,735) |
| Bonds Outstanding at December 31, 2004 | $ 2,973,548 |

The various issues comprising the outstanding debt are as follows (in thousands of dollars):

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| Series 1986 A | | |
| 5% maturing in 2017 with annual sinking fund requirements beginning in 2015 | $ 4,495 | $ 4,495 |
| Series 1989 A | | |
| 7.5% maturing in 2010 with annual sinking fund requirements beginning in 2009 | 28,890 | 28,890 |
| Series 1991 A | | |
| 6.25% maturing in 2004 | | 260 |
| 6.3% to 6.4% capital appreciation serial bonds maturing annually from 2004 to 2006 | 2,538 | 3,329 |
| 6.5% maturing in 2018 | 28,755 | 28,755 |
| 5.75% maturing in 2019 | | 130,680 |
| | 31,293 | 163,024 |
| Series 1993 B | | |
| 5.5% to 7.25% maturing annually from 2004 to 2009 | 376,435 | 381,760 |
| 5.5% maturing in 2017 with annual sinking fund requirements beginning in 2015 | 146,625 | 146,625 |
| 6% maturing in 2018 | 97,790 | 97,790 |
| 5.5% maturing in 2021 with annual sinking fund requirements beginning in 2019 | 194,510 | 194,510 |
| 6% maturing in 2022 | 157,740 | 157,740 |
| 6.25% maturing in 2023 | 64,390 | 64,390 |
| 6% maturing annually from 2025 to 2026 | 32,985 | 32,985 |
| | 1,070,475 | 1,075,800 |

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| Series 1993 C | | |
| 5% to 7% maturing annually from 2004 to 2007 | $ 87,645 | $ 124,400 |
| 7% maturing in 2013 with annual sinking fund requirements beginning in 2010 | 20,965 | 20,965 |
| 5% maturing in 2021 with annual sinking fund requirements beginning in 2014 | | 57,590 |
| | 108,610 | 202,955 |
| Series 1993 D | | |
| 5.6% maturing in 2016 with annual sinking fund requirements beginning in 2015 | - | 34,735 |
| Series 1995 A | | |
| 5.125% maturing in 2012 | 14,090 | 14,090 |
| Series 1996 A | | |
| 5.5% to 6% maturing annually from 2004 to 2006 | 69,255 | 105,805 |
| 5.6% maturing in 2010 | 1,060 | 1,060 |
| 5.625% to 5.7% maturing annually from 2012 to 2016 | 83,320 | 83,320 |
| 5.625% maturing in 2024 with annual sinking fund requirements beginning in 2017 | 62,310 | 62,310 |
| | 215,945 | 252,495 |
| Series 1996 B | | |
| 6% maturing in 2006 | 12,000 | 12,000 |
| 5.8% maturing in 2016 | 22,920 | 22,920 |
| 5.875% maturing in 2021 with annual sinking fund requirements beginning in 2020 | 101,955 | 101,955 |
| | 136,875 | 136,875 |
| Series 1997 A | | |
| 5.375% maturing in 2024 | 29,185 | 29,185 |
| Series 1999 A | | |
| 5.2% maturing in 2010 | 5,000 | 5,000 |
| 5.75% maturing in 2026 with annual sinking fund requirements beginning in 2023 | 150,000 | 150,000 |
| | 155,000 | 155,000 |
| Series 1999 B | | |
| 5.55% to 5.7% maturing annually from 2014 to 2017 | 40,035 | 40,035 |
| 5.75% maturing in 2024 | 76,690 | 76,690 |
| | 116,725 | 116,725 |

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| Series 1999 C (Federally Taxable) | | |
| 6.48% to 7.05% maturing annually from 2004 to 2007 | $ 2,945 | $ 3,805 |
| Series 1999 D | | |
| 5.45% maturing in 2004 | | 1,500 |
| 6% maturing in 2009 with annual sinking fund requirements beginning in 2005 | 7,470 | 7,470 |
| 6.45% maturing in 2014 with annual sinking fund requirements beginning in 2010 | 7,500 | 7,500 |
| 6.7% maturing in 2019 with annual sinking fund requirements beginning in 2015 | 35,875 | 35,875 |
| 6.75% maturing in 2026 with annual sinking fund requirements beginning in 2020 | 80,125 | 80,125 |
| | 130,970 | 132,470 |
| Series 2003 A | | |
| 5.5% maturing annually from 2010 to 2012 | 171,760 | 171,760 |
| Series 2003 B (Federally Taxable) | | |
| 6.48% maturing in 2012 | 9,860 | 9,860 |
| Series 2003 C | | |
| 2.75% to 5.375% maturing annually from 2004 to 2017 | 111,655 | 112,920 |
| Series 2003 D | | |
| 2.25% maturing in 2004 | | 645 |
| 4.125% to 5.375% maturing annually from 2010 to 2015 | 228,370 | 228,370 |
| 5.125% maturing in 2023 with annual sinking fund requirements beginning in 2016 | 42,890 | 42,890 |
| 5.125% maturing in 2026 with annual sinking fund requirements beginning in 2025 | 21,660 | 21,660 |
| | 292,920 | 293,565 |
| Series 2003 E (Federally Taxable) | | |
| 5.23% maturing in 2011 | 6,740 | 6,740 |
| 5.5% maturing in 2014 | 13,410 | 13,410 |
| 6.58% maturing in 2026 | 4,195 | 4,195 |
| | 24,345 | 24,345 |
| Series 2003 F | | |
| 2.25% maturing in 2004 | | 240 |
| 3.8% to 5.5% maturing annually from 2009 to 2017 | 87,715 | 87,715 |
| | 87,715 | 87,955 |

| | December 31, 2004 | 2003 |
|---|---|---|
| Series 2003 G (Ferderally Taxable) | | |
| 3.98% to 4.37% maturing annually from 2007 to 2008 | $ 395 | $ 395 |
| 5.55% maturing annually from 2013 to 2014 | 6,425 | 6,425 |
| | 6,820 | 6,820 |
| Series 2004 A | | |
| 7-day auction rate securities maturing in 2019 | 73,550 | |
| 35-day auction rate securities maturing in 2019 | 79,975 | |
| 35-day auction rate securities maturing in 2020 | 52,125 | |
| | 205,650 | |
| Series 2004 B (Federally Taxable) | | |
| 28-day auction rate securities maturing in 2021 | 17,325 | |
| | 2,973,548 | 3,057,769 |
| Less: | | |
| Current maturities of bonds | 91,005 | 85,200 |
| Unamortized discount | 19,433 | 35,531 |
| | $ 2,863,110 | $ 2,937,038 |

The fair market value of the Agency's long-term debt was estimated using the Dobbins Scale. The individual maturities were priced and summed to arrive at an estimated fair market value of $3,084,675,000 and $3,183,616,000 at December 31, 2004 and 2003, respectively.

Certain proceeds of the Series 1986 A, 1989 A, 1991 A, 1993 B and C, 1995 A, 1996 A, 1997 A, 1999 A, B and C, 2003 A, B, C, D, E, F and G and 2004 A and B bonds, were used to establish trusts for refunding $4,752,875,000 of previously issued bonds. At December 31, 2004, $4,307,645,000 of these bonds has been redeemed leaving $445,230,000 still outstanding. Under these Refunding Trust Agreements, obligations of, or guaranteed by the United States have been placed in irrevocable Refunding Trust Funds maintained by the Bond Fund Trustee. The government obligations in the Refunding Trust Funds, along with the interest earnings thereon, are pledged solely for the benefit of the holders of the refunded bonds and will be sufficient to pay all interest when due and to redeem at par all refunded bonds unredeemed at December 31, 2004 at various dates prior to or on their original maturities. Since the establishment of each Refunding Trust Fund, the refunded bonds are no longer considered outstanding obligations of the Agency.

The following table reflects principal debt service included in the designated year's rates. In accordance with the Resolution, these moneys are deposited into the Bond Fund for payment of the following year's current maturities. The debt service deposit requirements for bonds outstanding at December 31, 2004 are as follows (in thousands of dollars):

| Year | Principal | Interest* | Total |
|---|---|---|---|
| 2005 | $ 98,263 | $ 157,319 | $ 255,582 |
| 2006 | 118,345 | 150,366 | 268,711 |
| 2007 | 127,380 | 143,216 | 270,596 |
| 2008 | 134,250 | 133,976 | 268,226 |
| 2009 | 118,920 | 126,351 | 245,271 |
| 2010 to 2014 | 677,415 | 559,464 | 1,236,879 |
| 2015 to 2019 | 759,090 | 369,353 | 1,128,443 |
| 2020 to 2024 | 769,545 | 146,123 | 915,668 |
| 2025 | 79,335 | 4,737 | 84,072 |
| Total | $ 2,882,543 | $ 1,790,905 | $ 4,673,448 |

* Assumes interest rates of 3.05%, 3.66%, 3.644% and 5.09% for the 1999 A, 1999 B, 2004 A and 2004 B swaps, respectively.

Current maturities of $91,005,000 at December 31, 2004 were collected through rates during 2004 and deposited monthly into the Bond Fund to make the January 1, 2005 principal payment.

The bonds are special obligations of the Agency, payable solely from and secured solely by (1) revenues (as defined by the Resolution) after payment of operating expenses (as defined by the Resolution) and (2) other monies and securities pledged for payment thereof by the Resolution.

The Resolution requires the Agency to deposit into special funds all proceeds of bonds issued and all revenues (as defined by the Resolution) generated as a result of the Initial Project Power Sales Agreements and the 1981 PCA. The purpose of the individual funds is specifically defined in the Resolution.

In May, the Agency refinanced some of its existing debt to take advantage of historically low interest rates. The Agency issued $222,975,000 of Series 2004 A and B Refunding Bonds to refund $223,005,000 of previously issued bonds. Net present value savings realized were $21,094,000 with debt service savings of from $2,181,000 to $3,416,000 per year through 2019 and $339,000 and $230,000 in 2020 and 2021, respectively.

Interest on the bonds is payable semi-annually. Certain of the bonds are subject to redemption prior to maturity at the option of the Agency, on or after the following dates, at a maximum of 102% of the respective principal amounts:

| | |
|---|---|
| Series 1986 A | January 1, 1996 |
| Series 1991 A | January 1, 2003 |
| Series 1993 B | January 1, 2003 |
| Series 1995 A | January 1, 2006 |
| Series 1996 A | January 1, 2007 |
| Series 1997 A | January 1, 2008 |
| Series 1999 A and B | January 1, 2009 |
| Series 1999 D | January 1, 2010 |
| Series 2003 C, D, and F | January 1, 2013 |
| Series 2004 A and B | Any Interest Payment Date |

## H. COMMITMENTS AND CONTINGENCIES

The Price-Anderson Act limits the public liability for a nuclear incident at a nuclear generating unit to $10,800,000,000, which amount is to be covered by private insurance of $300,000,000 and agreements of indemnity with the NRC for the remainder. Such private insurance and agreements of indemnity are carried by PEC on behalf of all co-owners of the initial project. The terms of this coverage require the owners of all licensed facilities to provide up to $100,600,000 per year per unit owned (adjusted annually for inflation) in the event of any nuclear incident involving any licensed facility in the nation, with an annual maximum assessment of $10,000,000 per unit owned. If any such payments are required, the Agency would be liable for 18.33% and 16.17% of those payments applicable to the Brunswick and Harris plants, respectively.

The Price Anderson Act was first enacted in 1957 and has been renewed three times, the last in 1998. The Act expired in 2002 but nuclear reactors in operation when the Act expired remain covered by the law. Congress is currently holding hearings considering reauthorization of the legislation that could include increased limits and assessments per unit owned. The final outcome of this matter cannot be predicted at this time.

Primary property damage insurance coverage purchased for each nuclear plant is $500,000,000. Excess property damage, decontamination, and decommissioning liability insurance of $2,000,000,000 have also been purchased for each nuclear plant.

# NCEMPA SCHEDULES OF REVENUES AND EXPENSES PER BOND RESOLUTION AND OTHER AGREEMENTS

**($000s)**

| | Year Ended December 31, 2004 | | | Year Ended December 31, 2003 | | |
|---|---|---|---|---|---|---|
| | Project | Supplemental | Total | Project | Supplemental | Total |
| **Revenues:** | | | | | | |
| Sales to participants | $ 361,073 | $ 134,800 | $ 495,873 | $ 353,354 | $ 122,635 | $ 475,989 |
| Sales to utilities | 39,101 | | 39,101 | 35,639 | | 35,639 |
| Investment income | 13,055 | 314 | 13,369 | 13,173 | 347 | 13,520 |
| Excess Reserve and Contingency Fund valuation | 10,645 | | 10,645 | 7,462 | | 7,462 |
| Special supplemental reserve fund withdrawal | | 42 | 42 | | 2,519 | 2,519 |
| Other revenues | 59 | | 59 | 10,117 | | 10,117 |
| Total Revenues | 423,933 | 135,156 | 559,089 | 419,745 | 125,501 | 545,246 |
| **Expenses:** | | | | | | |
| Operation and maintenance | 43,345 | 5 | 43,350 | 43,144 | 5 | 43,149 |
| Fuel | 44,595 | | 44,595 | 42,212 | | 42,212 |
| Power coordination services: | | | | | | |
| Purchased power | 9,851 | 106,048 | 115,899 | 10,408 | 90,482 | 100,890 |
| Transmission and distribution | - | 20,835 | 20,835 | | 20,555 | 20,555 |
| Other | - | 330 | 330 | | 492 | 492 |
| Total power coordination services: | 9,851 | 127,213 | 137,064 | 10,408 | 111,529 | 121,937 |
| Administrative and general – PEC | 23,266 | | 23,266 | 18,479 | | 18,479 |
| Power Agency services | 3,253 | 4,501 | 7,754 | 2,968 | 3,988 | 6,956 |
| Taxes | | | | | | |
| Amounts in lieu of taxes | 3,405 | | 3,405 | 3,484 | | 3,484 |
| Gross receipts tax | 11,626 | 4,253 | 15,879 | 11,379 | 4,077 | 15,456 |
| Total taxes | 15,031 | 4,253 | 19,284 | 14,863 | 4,077 | 18,940 |
| Debt service: | | | | | | |
| Letters of credit commitment fees and administrative costs | 453 | | 453 | 462 | | 462 |
| Debt service | 252,962 | 206 | 253,168 | 256,048 | 189 | 256,237 |
| Total debt service | 253,415 | 206 | 253,621 | 256,510 | 189 | 256,699 |
| Special funds deposits: | | | | | | |
| Special Supplemental Reserve | | | - | | 70 | 70 |
| Reserve and contingency fund | 26,414 | | 26,414 | 26,620 | | 26,620 |
| Decommissioning fund | 4,763 | | 4,763 | 4,541 | | 4,541 |
| Total special funds deposits | 31,177 | - | 31,177 | 31,161 | 70 | 31,231 |
| Total Expenses | 423,933 | 136,178 | 560,111 | 419,745 | 119,858 | 539,603 |
| Revenues Over (Under) Expenses | $ - | $ (1,022) | $ (1,022) | $ - | $ 5,643 | $ 5,643 |

Note: The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2004 and 2003, respectively.

See accompanying Independent Auditors' Report.

# NCEMPA SCHEDULE OF BUDGETARY COMPARISON

($000)

| | 2004 Budget Original | 2004 Budget Final | Actuals (Budgetary Basis) | Positive (Negative) Variance With Final Budget* |
|---|---|---|---|---|
| **Revenues:** | | | | |
| Sales to participants | $ 493,642 | $ 493,642 | $ 495,873 | $ 2,231 |
| Sales to utilities | 33,933 | 33,933 | 39,101 | 5,168 |
| Investment income | 15,878 | 15,878 | 13,369 | (2,509) |
| Appropriated fund balance | 2,907 | 2,907 | | (2,907) |
| Excess Reserve and Contingency Fund Valuation | 10,193 | 10,193 | 10,645 | 452 |
| Other revenues | 617 | 617 | 101 | (516) |
| Total Revenues | 557,170 | 557,170 | 559,089 | 1,919 |
| **Expenses:** | | | | |
| Operation and maintenance | 44,335 | 44,335 | 43,350 | 985 |
| Fuel | 31,552 | 31,552 | 44,595 | (13,043) |
| Power coordination expenses: | | | | |
| Purchased power | 122,044 | 122,044 | 115,899 | 6,145 |
| Transmission and distribution | 20,116 | 20,116 | 20,835 | (719) |
| Other | 300 | 300 | 330 | (30) |
| Total power coordination expenses | 142,460 | 142,460 | 137,064 | 5,396 |
| Administrative and general – PEC | 21,316 | 21,316 | 23,266 | (1,950) |
| Power Agency services | 8,355 | 8,355 | 7,754 | 601 |
| Taxes | 20,786 | 20,786 | 19,284 | 1,502 |
| Debt service | 257,230 | 257,230 | 253,621 | 3,609 |
| Special funds deposits | 31,136 | 31,136 | 31,177 | (41) |
| Total Expenses | 557,170 | 557,170 | 560,111 | (2,941) |
| Revenues Over (Under) Expenses | $ - | $ - | $ (1,022) | $ (1,022) |

* The budget was amended in March 2005 due to cost overruns for fossil fuel. These costs were higher due to higher coal and transportation costs. In addition, the fossil units ran more than expected

Note: The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2004.

See accompanying Independent Auditors' Report.

# NCEMPA SCHEDULES OF CHANGES IN ASSETS OF FUNDS INVESTED

**($000)**

| | Funds Invested January 1, 2003 | Debt Proceeds | Power Billing Receipts | Investment Income | Disburse-ments | Transfers | Funds Invested December 31, 2003 | Debt Proceeds | Power Billing Receipts | Investment Income | Disburse-ments | Transfers | Funds Invested December 31, 2004 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Bond Fund: | | | | | | | | | | | | | |
| Interest account | $ 91,550 | $ (8,202) | $ - | $ 435 | $ (171,564) | $ 176,749 | $ 88,968 | $ (5,141) | $ | $ 526 | $ (171,062) | $ 167,244 | $ 80,535 |
| Reserve account | 209,493 | (5,574) | | 10,174 | | (10,184) | 203,909 | (12,339) | | 9,169 | (1,039) | (8,166) | 191,534 |
| Principal account | 82,792 | | | 424 | (82,695) | 84,874 | 85,395 | | | 678 | (85,200) | 90,294 | 91,167 |
| | 383,835 | (13,776) | - | 11,033 | (254,259) | 251,439 | 378,272 | (17,480) | - | 10,373 | (257,301) | 249,372 | 363,236 |
| Reserve and Contingency Fund: | 20,808 | (557) | | 816 | (19,588) | 18,688 | 20,167 | 2,321 | | 709 | (26,691) | 25,937 | 22,443 |
| Decommissioning Fund | 4,759 | | | 244 | | (2,731) | 2,272 | | | 153 | | (153) | 2,272 |
| Special Reserve Fund | 1,014 | | | 53 | | (113) | 954 | | | 18 | | (972) | - |
| Revenue Fund | 25,474 | (167) | 350,761 | 280 | 16,032 | (373,708) | 18,672 | (1,737) | 365,208 | 852 | 3,402 | (344,462) | 41,935 |
| Operating Fund: | | | | | | | | | | | | | |
| Working Capital account | 26,102 | | | 799 | (70,488) | 74,283 | 30,696 | | | 969 | (74,281) | 54,475 | 11,859 |
| Fuel account | 21,804 | | | | (39,217) | 42,191 | 24,778 | | | | (45,971) | 43,899 | 22,706 |
| | 47,906 | - | - | 799 | (109,705) | 116,474 | 55,474 | - | - | 969 | (120,252) | 98,374 | 34,565 |
| Supplemental Fund: | | | | | | | | | | | | | |
| Supplemental account | 8,471 | | 96,722 | 224 | (107,019) | 26,711 | 25,109 | | 119,976 | 276 | (111,165) | (14,018) | 20,178 |
| Special Supplemental | 633 | | 34,104 | 72 | | (36,760) | (1,951) | | 9,843 | 63 | (8,955) | (2,398) | (3,398) |
| Reserve | 9,104 | - | 130,826 | 296 | (107,019) | (10,049) | 23,158 | - | 129,819 | 339 | (120,120) | (16,416) | 16,780 |
| | $ 492,900 | $ (14,500) | $ 481,587 | $ 13,521 | $ (474,539) | $ - | $ 498,969 | $ (16,896) | $ 495,027 | $ 13,413 | $ (520,962) | $ 11,680 | $ 481,231 |

Note: The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2004 and 2003, respectively.

See accompanying Independent Auditors' Report.

# NCEMPA STATISTICAL HIGHLIGHTS

## Ten Years at a Glance (Unaudited)

| | 2004 | 2003 | 2002 | 2001 | 2000 |
|---|---|---|---|---|---|
| Megawatt-hour Sales (MWh) | 7,185,123 | 6,965,926 | 7,060,341 | 6,765,157 | 6,924,955 |
| Peak Billing Demand (kW) | 1,256,605 | 1,293,107 | 1,319,861 | 1,284,897 | 1,265,241 |
| Operating Revenues | $535,033,000 | $521,745,000 | $500,285,000 | $458,160,000 | $456,845,000 |
| Excess (Deficiency) of Revenues over Expenditures | $(1,022,000) | $5,643,000 | ($12,231,000) | $0 | $0 |
| Sales to PEC (Revenues) | $39,101,000 | $35,639,000 | $36,013,000 | $33,279,000 | $33,910,000 |
| Average Monthly Power Purchases by Cities (MWh) | 598,760 | 580,494 | 588,362 | 563,763 | 577,080 |
| Average Monthly Billings to Cities | $41,323,000 | $39,666,000 | $38,689,000 | $35,407,000 | $35,245,000 |

| | 1999 | 1998 | 1997 | 1996 | 1995 |
|---|---|---|---|---|---|
| Megawatt-hour Sales (MWh) | 6,569,652 | 6,556,169 | 6,273,385 | 6,291,401 | 6,142,495 |
| Peak Billing Demand (kW) | 1,217,221 | 1,190,030 | 1,185,129 | 1,116,786 | 1,194,209 |
| Operating Revenues | $445,358,000 | $449,489,000 | $446,742,000 | $460,674,000 | $462,664,000 |
| Excess (Deficiency) of Revenues over Expenditures | $0 | ($2,676,000) | $0 | $0 | $0 |
| Sales to PEC (Revenues) | $36,486,000 | $35,027,000 | $38,142,000 | $38,416,000 | $40,901,000 |
| Average Monthly Power Purchases by Cities (MWh) | 547,471 | 546,347 | 522,782 | 524,283 | 511,874 |
| Average Monthly Billings to Cities | $34,073,000 | $34,539,000 | $34,050,000 | $35,188,000 | $35,147,000 |

# *Town of* Apex

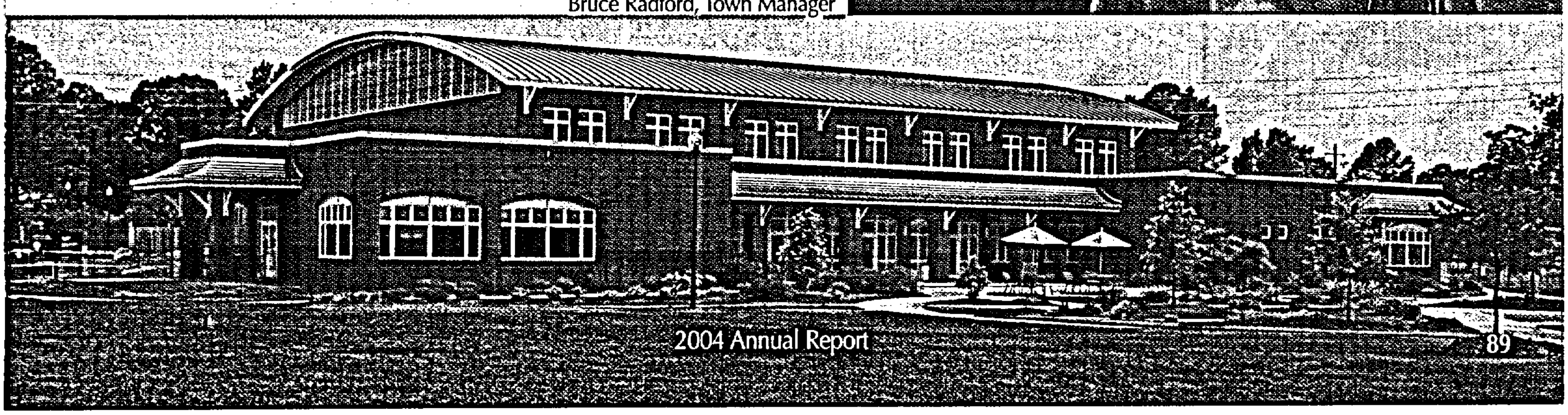
As town officials and residents of Apex can confirm, it is better to be proactive than reactive when faced with unprecedented growth. Having been designated "The Best Small Town in North Carolina" in the mid-1990s; the town experienced a population explosion. The town's resources and infrastructure could easily have been overwhelmed by a nearly 500% increase in the number of residents since 1990. With a population nearing 30,000 and the potential for that number to double in the next eight to 10 years, the town has been facing increased congestion, loss of open space and the prospect of losing its sense of identity and the small-town quality of life it valued so highly.

Apex developed a comprehensive Unified Development Ordinance in the late 1990's and has made a serious effort to address development issues and design an orderly growth process to avoid the mistakes observed in other Triangle communities experiencing rapid growth. The small-town feel has been bolstered by a major streetscape renovation project that has restored the downtown area and recaptured its historic flavor. Citizens indicated their approval of the growth management plan and process by turning out at the polls in large numbers and giving overwhelming support for the use of bond financing for transportation and parks and recreation. With 86 percent of voters approving, a $13 million referendum was passed for new park and recreation projects together with improvements to existing facilities. A $9.5 million bond issue for road improvement projects was also approved by a large majority.

The organization and delivery of municipal services has been enhanced by a Town Campus project that clusters municipal facilities and improves administrative organization, access to municipal services and operational efficiency. Electric power services have kept pace with growth and have benefited from economies of scale. Customer service will continue to improve and costs will become even more affordable over time as operations become more efficient and cost effective.

Having issued an ordinance restricting permits for single-family homes between 1998 and 2002, the town feels that it now has its population growth under control. With the drafting of a new Comprehensive Plan in 2004, town leaders feel that Apex is well-positioned for future growth and are working to ensure that their vision for that future is achieved.

Mayor Keith Weatherly and
Bruce Radford, Town Manager



# *City of* Albemarle

With the creation of jobs and business opportunities among the Albemarle City Council's highest priorities, the city sought to participate in the development of an industrial park distinct in its plan and focus. Albemarle joined the Stanly County Economic Development Commission (SCEDC) and ElectriCities in creating a unique solution: the state's first industrial park specifically designed to attract new industrial customers with the need for reliable, uninterruptible electric power.

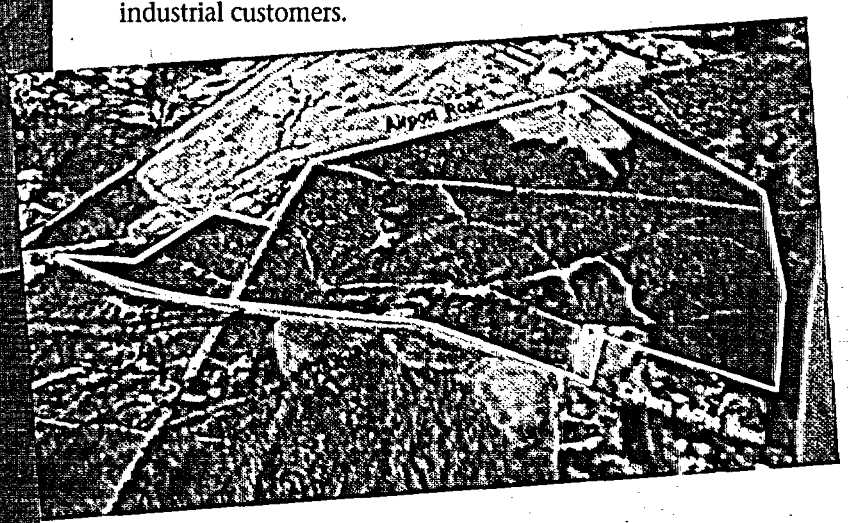
The Prime Power Park™, located on private property directly across from the airport, will feature a redundant power supply system, using a 1.8-MW generator to supply power to tenants under emergency conditions. Reliable, uninterruptible power is a key requirement for many industries that would suffer costly losses in the event of a power outage.

As part of the Charlotte Regional Partnership, a rapidly growing region of 2.3 million people, the site benefits from its proximity to the Charlotte area and the marketing strength and site location assistance provided by the Partnership arrangement.

A target marketing plan for identifying and recruiting prospective tenants for the park is being developed by The Sanford Holshouser Business Development Group, according to Robert Van Geons, executive director SCEDC. Examples of industries that would find redundant power attractive include injection plastic molding operations and high-end precision manufacturers.

"This facility will make the City of Albemarle and Stanly County more competitive in recruiting certain types of commercial and/or industrial customers," Van Geons said. "That, in turn, will help increase tax revenue, create jobs and boost investment in the community. The SCEDC looks forward to assisting city officials in this important effort."

With such a cutting-edge economic development asset, Albemarle may indeed have a competitive advantage in recruiting a highly-coveted segment of high-tech manufacturing. In addition, the project demonstrates the flexibility and unique benefits that public power communities can offer industrial customers.



Jack Neel, City Council and
Raymond Allen, City Manager

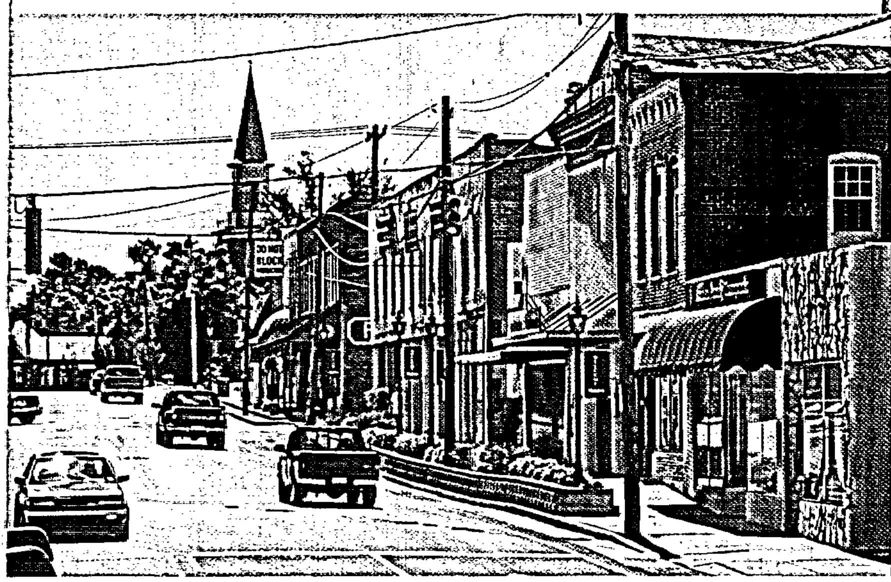
# *Town of* Maiden

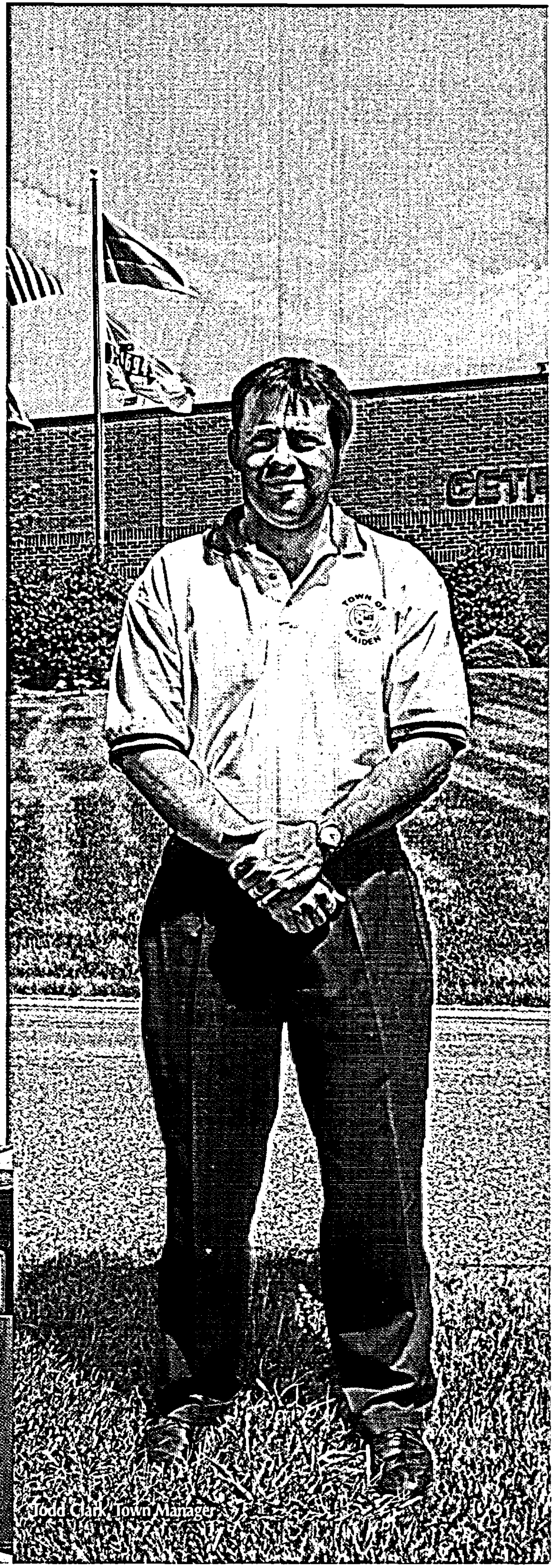
Faced with the loss of jobs in traditional industries, Maiden has sought to capitalize on its strengths to attract new and expanded industry. Located in a dynamic region of the state, Maiden benefits from its proximity to Hickory and the industry location resources of the Catawba County Economic Development Commission and the Charlotte Regional Partnership. With a skilled, productive labor force, strong manufacturing climate and exceptional quality of life, town leadership has welcomed opportunities to modernize and diversify the industrial base. Success in this undertaking is exemplified by the announcement in 2004 of a major expansion by the GETRAG Axle Plant.

One of the world's leading manufacturers of power-train technology for the automotive industry, GETRAG originally located in Maiden in 1986 and is primarily involved with the design and building of axles for passenger cars and open gears for diesel engines. The expanded operations are expected to bring over 300 new jobs and $81 million in new investment to the town. The GETRAG investment was supported by a Job Development Investment Grant (JDIG) from the state. A limited number of these grants are available annually and grant awards must undergo a two-stage approval process. With its designation as a Tier 4 county under the state's William S. Lee Act, the project satisfied the requirements for the JDIG initiative.

In his address at the project announcement, Mayor Zane Hudson remarked, "In response to challenging economic conditions, the Town of Maiden has heightened our commitment to working with existing companies, as well as prospective new employers, to ensure a vibrant economy in Catawba County. GETRAG's vision of ... 'We Do It Better' ... accurately summarizes the Town's commitment and ability to serve our industries and citizens."

When fully staffed, the new GETRAG expansion will nearly double the size of the company's employment in the town, and the direct and indirect benefits of the jobs and income will go a long way toward supporting the health and vitality of the local economy. The town is proud to provide a business friendly environment and looks forward to more success in its efforts to maintain a strong and vibrant setting in which to live and work.






Todd Clark, Town Manager

Mayor Barry Hayes and US Congressman Howard Coble

Dub Dickson and US Congressman Walter Jones

US Congresswoman Sue Myrick and Mayor Jennifer Stultz

ElectriCities Board of Directors, staff and Mayors from member cities meet with US Senator Elizabeth Dole as part the American Public Power Association's legislative rally in Washington, DC. (l-r): Clay Norris, Mayor Jennifer Stultz, Mayor Barry Hayes (ElectriCities Board of Directors), Mayor Roland Vaughan, Senator Dole, Terry Union, Jeanne Bonds, Dub Dickson (ElectriCities Board of Directors)

# ElectriCities Grassroots Initiatives Produce Results

State Senator David Hoyle addresses the ElectriCities Board of Directors

Town Manager and ElectriCities Board Member Sam Noble and his son, Hunter, with US Congressman G.K. Butterfield in Washington, DC during the National League of Cities legislative rally.

ElectriCities CEO Jesse C. Tilton III and his wife, Billie, with the James D. Donovan Individual Achievement Award, given to Tilton at the APPA Annual Meeting.

Mayor Roland Vaughan and US Congressman Howard Coble

Tarboro Mayor Donald Morris (and grandson) and Council Member Buck Price with US Congressman G.K. Butterfield in Washington, DC during the National League of Cities legislative rally.

ElectriCities

ElectriCities of North Carolina, Inc.

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Post Office Box 29513 • Raleigh, North Carolina 27626-0513
Telephone: 919.760.6000 • Facsimile: 919.760.6050 • Web Site: http://www.electricities.com

PRICEWATERHOUSECOOPERS

# Saluda River Electric Cooperative, Inc.

## Financial Statements
## December 31, 2004 and 2003

# Saluda River Electric Cooperative, Inc.
## Index
## December 31, 2004 and 2003

PRICEWATERHOUSECOOPERS

**PricewaterhouseCoopers LLP**
2030 Falling Water Rd. Suite 280
Knoxville TN 37922
Telephone (865) 769 2000
Facsimile (865) 769 2001

## Report of Independent Auditors

To the Board of Trustees of
Saluda River Electric Cooperative, Inc.:

In our opinion, the accompanying balance sheets and the related statements of operations and patronage capital deficit, and of cash flows present fairly, in all material respects, the financial position of Saluda River Electric Cooperative, Inc., ('the Company") at December 31, 2004 and 2003, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*.

PricewaterhouseCoopers LLP

April 20, 2005

# Saluda River Electric Cooperative, Inc.
## Balance Sheets
## December 31, 2004 and 2003

| *(in thousands of dollars)* | 2004 | 2003 |
|---|---|---|
| **Assets** | | |
| Electric plant | | |
| In-service | $ 96,773 | $ 92,172 |
| Accumulated depreciation | (32,050) | (29,084) |
| | 64,723 | 63,088 |
| Nuclear fuel, at amortized cost | 5,989 | 6,938 |
| Net electric plant | 70,712 | 70,026 |
| Other assets and investments | | |
| Investments in associated organizations | 1,041 | 1,136 |
| Special deposits | 6,508 | 6,761 |
| Decommissioning fund | 54,038 | 52,246 |
| Other assets | - | 71 |
| Total other assets and investments | 61,587 | 60,214 |
| Current assets | | |
| Cash and cash equivalents | 8,826 | 11,168 |
| Accounts receivable | 13,410 | 13,667 |
| Prepaid expenses and other current assets | 119 | 108 |
| Total current assets | 22,355 | 24,943 |
| | $ 154,654 | $ 155,183 |
| **Equities and Liabilities** | | |
| Equities and margins | | |
| Membership fees | $ 1 | $ 1 |
| Patronage capital deficit | (242,865) | (262,009) |
| Total equities and margins | (242,864) | (262,008) |
| Long-term debt | 299,893 | 305,723 |
| Current liabilities | | |
| Accounts payable and accrued expenses | 13,111 | 16,731 |
| Accounts payable - Affiliate | 600 | 685 |
| Total current liabilities | 13,711 | 17,416 |
| Commitments and contingencies | | |
| Other noncurrent liabilities | | |
| Asset retirement obligations | 83,440 | 82,223 |
| Other noncurrent liabilities | 474 | 11,829 |
| Total other noncurrent liabilities | 83,914 | 94,052 |
| | $ 154,654 | $ 155,183 |

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

# Saluda River Electric Cooperative, Inc.
## Statements of Operations and Patronage Capital Deficit
## Years Ended December 31, 2004 and 2003

| *(in thousands of dollars)* | 2004 | 2003 |
|---|---|---|
| **Operating revenues** | | |
| Electric sales to members | $ 139,386 | $ 130,308 |
| Sales to nonmembers | 6,212 | 6,611 |
| | 145,598 | 136,919 |
| **Operating expenses** | | |
| Fuel and purchased power | 117,231 | 116,158 |
| Transmission expense | 6,273 | 4,713 |
| Property taxes | 2,661 | 2,693 |
| Depreciation and accretion | 3,917 | 7,307 |
| Administrative and general | 3,126 | 3,951 |
| | 133,208 | 134,822 |
| Operating margin | 12,390 | 2,097 |
| Other income (expense) | | |
| Interest income | 2,259 | 2,151 |
| Other income | 119 | 3,446 |
| Gain on sale of asset | - | 613 |
| | 2,378 | 6,210 |
| Interest expense | (6,364) | (6,563) |
| Net margin before income taxes | 8,404 | 1,744 |
| Income tax benefit | 10,740 | - |
| Net margin before cumulative effect of accounting change | 19,144 | 1,744 |
| Cumulative effect of change in accounting for asset retirement obligations | - | (10,314) |
| Net margin (loss) | 19,144 | (8,570) |
| Patronage capital deficit, beginning of year | (262,009) | (253,439) |
| Patronage capital deficit, end of year | $ (242,865) | $ (262,009) |

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

# Saluda River Electric Cooperative, Inc.
## Statements of Cash Flows
## Years Ended December 31, 2004 and 2003

| *(in thousands of dollars)* | 2004 | 2003 |
|---|---|---|
| **Cash flows from operating activities** | | |
| Net margin (loss) | $ 19,144 | $ (8,570) |
| Adjustments to reconcile net margin (loss) to cash provided by operating activities | | |
| Depreciation and accretion | 3,917 | 7,307 |
| Gain on sale of fixed assets | - | (613) |
| Amortization of nuclear fuel | 5,094 | 5,058 |
| Deferred federal income taxes | (10,740) | - |
| Investment earnings on decommissioning fund | (1,792) | (1,951) |
| Noncash capital credits assigned to the Company | (3) | (4) |
| Interest accreted to (paid on) long-term debt | 5,070 | (5,145) |
| Cumulative effect of accounting change | - | 10,314 |
| Changes in other operating assets and liabilities | | |
| Accounts receivable | 257 | (502) |
| Interest receivable | (15) | 717 |
| Materials and supplies | - | 116 |
| Prepaid expenses | 3 | 2,292 |
| Accounts payable and accrued expenses | (3,704) | 2,177 |
| Other noncurrent liabilities | (614) | (182) |
| Net cash provided by operating activities | 16,617 | 11,014 |
| **Cash flows from investing activities** | | |
| Nuclear fuel additions | (4,146) | (7,537) |
| Investment in electric plant | (4,335) | (2,950) |
| Proceeds from disposition of electric plant | 71 | 6,724 |
| Return of capital from associated organizations | 98 | 146 |
| Decrease (increase) in special deposits | 253 | (53) |
| Net cash used in investing activities | (8,059) | (3,670) |
| **Cash flows from financing activities** | | |
| Principal payments of long-term debt | (10,900) | (6,360) |
| Net (decrease) increase in cash and cash equivalents | (2,342) | 984 |
| Cash and cash equivalents, beginning of year | 11,168 | 10,184 |
| Cash and cash equivalents, end of year | $ 8,826 | $ 11,168 |
| **Supplemental disclosure of cash flow information** | | |
| Cash paid for interest | $ 6,383 | $ 11,761 |

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

## 1. Organization and Basis of Presentation

Saluda River Electric Cooperative, Inc. (the "Company") is a member-owned, nonprofit cooperative of five electric membership cooperatives (the "Members") in South Carolina. The Company was formed in 1958. The Company's focus is to provide its Members with substantially all of their electric power requirements. The Company follows accounting principles generally accepted in the United States of America and the practices prescribed in the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission, as modified and adopted by the Rural Utilities Service ("RUS").

## 2. Summary of Significant Accounting Policies

### 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, as invoiced to the Company by Duke Power Company ("Duke"), and includes engineering and other indirect construction costs. The cost of renewals and betterments of property is capitalized, except for the cost of minor replacements, which is charged to maintenance expense. At the time properties are disposed of, the original cost plus 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.

During 1998, the Company concluded that its investment in the Catawba Nuclear Facility ("Catawba") was impaired based upon ongoing debt restructuring negotiations. As a result, based on an independent appraisal, the fair value of Catawba was determined to be approximately $51,800,000. Accordingly, the book value was written down to reflect this value, and the Company recognized an impairment loss of approximately $226,206,000.

### Depreciation and Decommissioning Expense

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

| | Estimated Lives |
|---|---|
| Catawba Nuclear Station ("Catawba") | 50-60 years |
| Diesel generation equipment | 14 years |

The amounts that have been recovered through rates for estimated decommissioning costs (plus interest thereon) are maintained in an external trust fund in compliance with NRC regulations. Investment earnings and realized gains generated from the external trust fund were maintained in the decommissioning fund with a corresponding increase to the reserve for decommissioning. However, effective January 1, 2003, the Company adopted SFAS 143, *Accounting for Asset Retirement Obligations* (Note 4).

Based on a 2003 site study of expected decommissioning costs, including the costs of decontamination, dismantling and site restoration, the Company's portion of such costs at the date of decommissioning was estimated to be approximately $544,909,000 assuming the date of decommissioning to be December 2043. The estimate assumes a future annual inflation rate of 4.5% in decommissioning costs. The decommissioning costs 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 likely 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, material and equipment.

In December 2003, the Nuclear Regulatory Commission ("NRC") extended the operating licenses of Catawba units 1 and 2 through December 2043, from December 2024 and December 2026, respectively.

**Fuel Costs**
The cost of nuclear fuel is amortized based on the rate of fuel usage. Nuclear fuel amortization expense equaled approximately $5,290,000 in 2004 and $5,255,000 in 2003 and is included in fuel and purchased power costs in the accompanying financial statements.

**Investments**
Investments in capital term certificates and patronage capital certificates are considered to be held-to-maturity and are carried at cost determined by specific identification. All realized and unrealized gains and losses are determined using the specific identification method.

**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. Investments with original maturities between three and twelve months are classified as short-term investments.

**Membership Fees and Patronage Capital Deficit**
The Company is organized and operates as a cooperative. Membership fees were assessed to each member upon formation of the Company. Patronage capital deficit is the accumulated net deficit of the Company.

**Income Tax Status**
The Company is a not-for-profit membership corporation subject to federal income taxes. 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 (the "Code"). In 1985, the Company reported as a taxable entity as a result of income received from Duke under a capacity and energy sell-back agreement applicable to Catawba. As a taxable electric cooperative, the Company has annually allocated its income and deductions between Member and nonmember activities. Any Member taxable income has been offset with a patronage exclusion. Deferred tax assets and liabilities are recognized for the expected tax consequences of temporary differences arising between the financial reporting bases of assets and liabilities and their reported amounts for income tax reporting purposes in accordance with the provisions of SFAS No. 109, *Accounting for Income Taxes.*

**Revenue Recognition**
Revenue is recognized as customers are billed for services provided.

**Derivative Instruments and Hedging Activities**
The fair value of derivative instruments are recorded on the balance sheet as an asset or liability. Changes in the fair value of derivative financial instruments are either recognized periodically in income or patronage capital (as a component of other comprehensive income), depending on whether the derivative is being used to hedge changes in fair value or cash flow.

**Asset Retirement Obligations**
The Company records a liability relating to the retirement and removal of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability. Over the life of the asset, the liability is accreted to its future value and eventually extinguished when the asset is taken out of service. The Company adopted SFAS 143 on January 1, 2003 (Note 4).

**Impairment of Long-Lived Assets**
The carrying value of intangible assets, property and equipment, and other long-lived assets is reviewed on a regular basis for the existence of facts that may suggest impairment. The Company recognizes an impairment loss when events or circumstances cause the carrying amount of an asset to exceed the expected undiscounted cash flows from its use and disposition. The measurement of the impairment loss to be recognized is based on the difference between the fair value and the carrying amount of the asset. At December 31, 2004 and 2003, no such impairment was indicated.

**Use of Estimates**
The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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 reported 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.

## 3. Electric Plant in Service

Electric plant in service included the following as of December 31, 2004 and 2003:

| *(in thousands of dollars)* | 2004 | 2003 |
|---|---|---|
| Electric plant in service | $ 91,591 | $ 91,935 |
| Land | 7 | 7 |
| Other plant | 5,175 | 230 |
| | $ 96,773 | $ 92,172 |

## 4. Asset Retirement Obligations

Effective January 1, 2003, the Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires the recognition of a liability, and capitalization of the associated asset retirement cost as part of the carrying amount of the long-lived asset, for "legal obligations" associated with the retirement of long-lived assets that result from the acquisition, construction, development, and/or normal operation of long-lived assets.

In prior years, the Company had recognized a decommissioning liability related to its ownership interest in the Catawba nuclear plant in accordance with NRC requirements. This previously recorded liability represents the pre-SFAS 143 obligation for the Company's nuclear plant asset retirement obligation ("ARO"), which amounted to $50 million at December 31, 2002. The adoption of SFAS No. 143 resulted in a change in the methodology of quantifying this nuclear decommissioning obligation in accordance with the new accounting standard. The Company has increased the nuclear decommissioning liability on the balance sheet to reflect new methodology, which amounted to $78 million at January 1, 2003. This nuclear decommissioning liability is included in the Asset Retirement Obligations line item on the Balance Sheets.

For each ARO identified, the Company calculated the net present value of the obligation as of the current period, the original and incremental cost of the long-lived asset at the time of initial operation, the cumulative effect of depreciation on the adjusted asset base, and accretion of the liability from the date of initial operation to the current and period.

The following table summarizes the original asset cost, the current ARO liabilities, the current fair market value of any assets legally restricted for purposes of settling the obligation, and the estimated future liability at the time of closure.

*(in thousands of dollars)*

| | Original Asset Cost | December 31, 2003 Obligation | December 31, 2004 Obligation | Fair Market Value of Assets | Estimated Future Liability |
|---|---|---|---|---|---|
| Nuclear plant | $ 32,088 | $ 82,223 | $ 83,440 | $ 52,284 | $ 544,909 |

## 5. Fair Value of Financial Instruments

The estimated fair values of the Company's financial instruments as of December 31, 2004 and 2003 are as follows:

*(in thousands of dollars)*

| | 2004 | | 2003 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Special deposits | $ 6,508 | $ 6,508 | $ 6,761 | $ 6,761 |
| Decommissioning fund | 54,038 | 52,284 | 52,246 | 50,231 |
| Cash and cash equivalents | 8,826 | 8,826 | 11,168 | 11,168 |
| | $ 69,372 | $ 67,618 | $ 70,175 | $ 68,160 |

The fair values of short-term investments, long-term investments, special deposits and the decommissioning fund are estimated based on quoted market prices for the investments held in the respective funds. The fair value of long-term debt is not readily determinable.

The amortized cost, gross unrealized holding gains, gross unrealized losses and fair value of securities by major security type at December 31, 2004 and 2003, were as follows:

| *(in thousands of dollars)* | 2004 | | | |
|---|---|---|---|---|
| | Cost | Gross Unrealized Gain | Gross Unrealized Loss | Estimated Fair Value |
| Corporate debt securities | $ 22,589 | $ 211 | $ (143) | $ 22,657 |
| Commercial paper | 8,000 | | | 8,000 |
| Cash and overnight investments | 10,333 | | | 10,333 |
| Equities | 12,200 | | (1,842) | 10,358 |
| U.S. Government and agency securities | 14,976 | 32 | (46) | 14,962 |
| State Government and agency securities | 1,274 | 34 | | 1,308 |
| | $ 69,372 | $ 277 | $ (2,031) | $ 67,618 |

| *(in thousands of dollars)* | 2003 | | | |
|---|---|---|---|---|
| | Cost | Gross Unrealized Gain | Gross Unrealized Loss | Estimated Fair Value |
| Corporate debt securities | $ 16,692 | $ 557 | $ (50) | $ 17,199 |
| Commercial paper | 10,000 | - | - | 10,000 |
| Cash and overnight investments | 14,125 | - | - | 14,125 |
| Equities | 12,200 | - | (2,679) | 9,521 |
| U.S. Government and agency securities | 15,884 | 169 | (102) | 15,951 |
| State Government and agency securities | 1,274 | 90 | - | 1,364 |
| | $ 70,175 | $ 816 | $ (2,831) | $ 68,160 |

No proceeds from the sale of marketable securities or related net realized gains were recorded in 2004 or 2003.

## 6. Investments in Associated Organizations

Investments in associated organizations are stated at cost at December 31, 2004 and 2003, consist of the following:

| *(in thousands of dollars)* | 2004 | 2003 |
|---|---|---|
| Patronage capital certificates | | |
| CoBank | $ 793 | $ 840 |
| Cooperative Electric Energy Utility Supply, Inc. ("CEE-US") | 158 | 158 |
| Other | 7 | 8 |
| | 958 | 1,006 |
| Investment in Federated Rural Electric Insurance Exchange | 35 | 82 |
| CFC Capital Term Certificates | 48 | 48 |
| | $ 1,041 | $ 1,136 |

The patronage capital certificates represent net margins of the respective associated organizations that have been allocated to the Company. These certificates will be redeemed by the Company in accordance with the respective associated organization's retirement policy. The capital term certificates invested in National Rural Utilities Cooperative Finance Corporation ("CFC") are unsecured and subordinated. The entire carrying amount of $48,000 of CFC Capital Term Certificates mature in 2080 and have an interest rate of 5%. The CFC capital term certificates are required to be maintained under the note agreement with CFC and are similar to compensating bank balances. All other investments are carried at cost.

## 7. Deposits

Special deposits of approximately $6,508,000 and $6,761,000 as of December 31, 2004 and 2003, respectively, consist of funds held in a depository account to satisfy working capital requirements as required by Duke.

## 8. Long-Term Debt

At December 31, 2004 and 2003, long-term debt consisted of the following:

| *(in thousands of dollars)* | 2004 | 2003 |
|---|---|---|
| RUS second subordinated payment note | $ 186,132 | $ 186,132 |
| RUS subordinated payment note, fixed interest rate of 5.23% | 100,457 | 95,387 |
| RUS senior payment note, fixed interest rate of 5.23% | 13,304 | 24,204 |
| | $ 299,893 | $ 305,723 |

On May 6, 1999, the Company signed an agreement with RUS. The terms of the agreement substituted the Company's then-outstanding obligations to RUS with three new debt instruments. The total carrying value of the new debt was equal to existing debt as of April 30, 1999. The new debt is payable to RUS annually from available cash and temporary investments, defined as available cash above $10 million as of November 30 each year, beginning the year ended December 31, 1999, and continuing through the year-ended December 31, 2008. During the years ended December 31, 2004 and 2003, the Company made debt principal payment of $10,900,000 and $6,360,000 from available cash, as provided in the revised debt agreement. In addition, during the year ended December 31, 2003, the Company made payments totaling $10,163,000, which were applied against accrued interest on the RUS subordinated note. At January 31, 2009, any remaining obligations under the new debt will be terminated, and the Company will be obligated to sell all of its assets, wind up operating activities and transfer remaining cash or liabilities to RUS.

Additional terms of the debt restructuring require the Company to sell Catawba and designate RUS as an agent to do so.

Except for funds from the sale of Catawba or other assets, as defined in the agreement, and except for a special agreement regarding a receivable from Santee Cooper as of December 31, 2002, which was received from Santee Cooper and paid to RUS in 2003, payments made to RUS will first be applied toward the senior payment note until fully satisfied, then to the subordinated payment note, and finally to the second subordinated payment note. Net proceeds from the sale of Catawba or other assets will be utilized first to reduce the interest and principal balances of the subordinated payment note, and then to reduce the second subordinated payment note.

Payments of interest for the senior payment note are made semiannually in April and December. To the extent the interest is not paid on the senior payment note, it is added to the principal balance. Interest accrued on the subordinated payment note is added to the principal balance of the subordinated payment note until the senior payment note principal and interest are paid in full. The second subordinated payment note does not bear interest.

In accordance with SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, no gain was recognized on this restructuring, since the total future cash payments, including interest, may exceed the carrying amount of the original debt. Additionally, no interest has been imputed to the second subordinated payment note. Interest expense for contingent payments shall be recognized in each period in which (a) it is probable that a liability has been incurred and (b) the amount of that liability can be reasonably estimated. If these criteria are met in the future, the amount of interest expense recognized would be deducted from the carrying amount of the restructured debt.

## 9. Income Taxes

The Company had member loss carryforwards of $82,405,000 and $77,306,000 at December 31, 2004 and 2003, respectively. Additionally, the Company has federal tax net operating loss carryforwards ("NOLs") at December 31, 2004, as follows:

*(in thousands of dollars)*

| Expiration Date | NOLs |
|---|---|
| 2005 | $ 12,877 |
| 2006 | - |
| 2007 | 7 |
| 2008 | 10 |
| 2009 | 19 |
| Thereafter | 932 |
| | $ 13,845 |

During 2004, RUS, as agent for Saluda began the bid solic itation process for the sale of Saluda's interest in Catawba (see Note 8). Based on management's understanding of the status of the auction process, it has been determined that the sale is likely to occur in 2008. Accordingly, the range of long-term business scenarios for Saluda has narrowed, and management has determined that the $10.7 million reserve established in prior years for potential tax obligations relating to the settlement of the RUS debt and other matters is no longer considered necessary. The 2004 tax benefit reflects the reversal of the reserve. The federal income expense in 2003 was zero due to available loss carryforwards.

## 10. Employee Benefit Plans

Effective January 1, 2004, all employees of the Company became employees of New Horizon Electric Cooperative.

Prior to January 1, 2004, substantially all employees of the Company participated in the National Rural Electric Cooperative Association ("NRECA") Retirement and Security Program, a defined benefit pension plan qualified under Section 401 and tax exempt under Section 501(a) of the Internal Revenue Code. The Company made monthly contributions to the program equal to the amounts accrued for pension expense except for the period beginning July 1, 1987 through September 30, 1996, when a moratorium on contributions was in effect. The moratorium resulted from the plan reaching its full limitation. 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 employers. The Company's pension costs were $0 and $128,000 in 2004 and 2003, respectively.

In addition to the NRECA Retirement and Security Program, substantially all employees of the Company participated in the NRECA SelectRe 401(k) Plan, a defined, multiemployer deferred income plan qualified under Section 401(k) and tax exempt under Section 501(a) of the Internal Revenue Code. The Company contributed $0 and $43,000 to the 401(k) plan in 2004 and 2003, respectively.

## 11. Postretirement Benefits

Prior to the transfer of employees to New Horizon, the Company sponsored an unfunded, defined benefit postretirement medical and dental insurance plan that covered substantially all of its employees. The benefit obligation of $396,000, which was included in other noncurrent liabilities at December 31, 2003 included unamortized dependent coverage of $146,000.

Effective January 1, 2004, New Horizon assumed the Company's postretirement benefit obligation of $288,000. In June 2004, the Company paid $288,000 to New Horizon to satisfy its obligation to New Horizon for assuming the postretirement benefit obligation.

Disclosures required by SFAS No. 132, *Employer's Disclosure about Pensions and Other Postretirement Benefits*, with regard to the Company's postretirement medical benefits are as follows:

| *(in thousands of dollars)* | | 2003 |
|---|---|---|
| Benefit obligation at December 31 | $ | 396 |
| Fair value of plan assets at December 31 | | |
| Funded status - accrued benefit cost recognized in the statement of financial position | $ | 396 |
| Weighted-average assumptions as of December 31 | | |
| Discount rate | | 6.00% |
| Rate of compensation increase | | N/A |
| Health care trend rate | | 10.0% |
| Benefit cost | | 30 |
| Employer contribution | $ | - |
| Plan participants' contributions | $ | - |
| Benefits paid | $ | - |

## 12. Commitments and Contingencies

### Purchased Power

On February 6, 1981, the Company entered into (a) the Catawba Purchase, Construction and Ownership agreement with Duke, together with an (b) Operating and Fuel Agreement and (c) an Interconnection Agreement (the "Contracts"). Contracts (a) and (b) provide for the purchase by the Company of an 18.75% undivided interest in Unit No. 1 of Catawba together with a 9.375% 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 amounted to approximately $59,503,000 as of December 31, 2004, and approximately $59,847,000 as of December 31, 2003, including capitalized interest expense, which is included in the accompanying balance sheets in electric plant in service.

Pursuant to the Contracts, Duke provided certain supplemental power to the Company through December 31, 2000. Effective January 1, 2001, the Company became a member of Central Electric Power Company ("Central") and contracted with South Carolina Public Service Authority ("Santee Cooper") under the Power Sales Agreement (the "PSA") to purchase all of its supplemental capacity and energy from Santee Cooper. Pursuant to the PSA, Santee Cooper would serve all of the Company's power needs over and above that which the Company receives from its alternative sources.

On October 25, 2001, the Company notified Santee Cooper in writing that it would be unable to pay the power bill for September 2001, due to its adverse cash position. Pursuant to the PSA, Santee Cooper notified the Company and Central that the PSA was terminated on October 25, 2001, and that, subject to the Wholesale Power Contract ("WPC") between the Company and Central, Santee Cooper was thereafter providing the Company's power requirements to Central under the Coordination Agreement ("CA") between Central and Santee Cooper. Subsequently, Santee Cooper has billed Central for the Company's power usage under the CA. Central disputed its obligation to the Company under the WPC. As of December 31, 2001, the Company owed Santee Cooper approximately $5,400,000, including interest, for power received under the PSA.

On March 4, 2002, the Company filed in the South Carolina Court of Common Pleas for the Eighth Circuit an Action for Declaratory Judgment requesting the court to order, among other things, that Central has a legal obligation and contractual duty to provide power to the Company pursuant to the Central WPC. At the same time, the Company also filed with the court an Action for an Injunction With a Motion for a Temporary Restraining Order to require Central to continue to serve the Company under the WPC until the Action for Declaratory Judgment is adjudicated.

Subsequent to the filings, Central verbally agreed to initiate negotiations with the Company regarding the WPC. Based upon Central's actions, the Company's Board of Trustees agreed to rescind the lawsuits and begin negotiations. The negotiations resulted in a settlement ("Settlement") being reached between the Company, Santee Cooper, and Central (collectively, "the Parties"). On February 27, 2003, RUS approved the Settlement. Under the terms of the Settlement, (1) Santee Cooper agreed to refund to the Company approximately $3,400,000 for power received under the PSA in 2001 (refund was received from Santee Cooper in March 2003); (2) Central agreed to sell electric power to the Company, subject to the terms of the WPC, and the Company agreed to pay an adder to Central of .85 mills per kWh over and above the rate paid by other Central members. Also, an additional adder of up to .25 mills per kWh may be paid to Central should Santee Cooper incur certain costs to upgrade the Duke transmission system; (3) Santee Cooper agreed to purchase all of Saluda River's diesel generators for $6,724,000 (sale was completed in April 2003); and (4) Central reaffirmed to the Company its intent to develop a single transmission rate for all of Central's members when Saluda River's members begin purchasing power requirements directly from Central.

As discussed above, during 2001, as a result of increased power costs from Santee Cooper, the Company incurred significant operating losses and suffered constraints on its ability to meet its obligations as they came due. For the year ended December 31, 2001, the Company incurred an operating loss of $13,231,000. As of December 31, 2001, the Company had a working capital deficit of $917,000 (excluding current obligations for accrued interest that are not currently payable) and a patronage capital deficit of $258,790,000. The Company's rates charged to its members are generally fixed, and upward cost pressures on its purchased power expenses resulted in operating losses for 2001. However, with the more stable rates for power purchased, pursuant to the WPC since October 26, 2001, and with the resolution of all disputes with Santee Cooper and Central, culminating in the Settlement, the Company's current financial projections indicate that the Company will be able to secure its power requirements at rates that enable it to generate sufficient operating margins to meet its continuing obligations.

Duke purchases 50% of the energy produced by Catawba in a nuclear reliability exchange as well as Catawba surplus energy from the Company, which is included in electric sales to nonmembers in the accompanying statements of operations and patronage capital deficit. The cost of power purchased from Duke, as well as power purchased by the Company for its members from Santee Cooper, Central and Broad River Electric Cooperative, Inc., has been recorded as purchased power in the accompanying statements of operations and patronage capital deficit.

**Litigation**
During the normal course of business, the Company may become involved in litigation incidental to the business. The Company believes it is adequately insured for any potential loss exposure, and management believes that the ultimate resolution of these matters will not have a material adverse effect on the Company's results of operations, financial position or cash flows.

**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 their facilities used for the enrichment of uranium included in nuclear fuels. In order to decommission facilities, the DOE estimates that it would need to charge utilities a total of $150,000,000 annually for 15 years based on enrichment services provided. Based on an estimate from Duke covering the 15 years, at December 31, 2003 the Company recorded its share of the liability, which totaled approximately $2,569,000. A corresponding asset was recorded as nuclear fuel and is being amortized to nuclear fuel expense over the 15 year assessment period. On an annual basis, payments are made to the DOE. The estimated remaining liability of approximately $474,000 and $693,000 at December 31, 2004 and 2003, respectively, is included in the accompanying balance sheets in other noncurrent liabilities.

**Disposition of Spent Nuclear Fuel**
Final disposition of spent nuclear fuel (Note 2) may require future adjustments to fuel expense. Pending ultimate disposition, sufficient storage capacity for spent fuel is available through 2008.

**Operating Leases**
The Company leases certain buildings, office equipment, information technology equipment and metering equipment from New Horizon (Note 14) that are accounted for as operating leases. On an annual basis, the Board of Trustees approves the upcoming year's payment. The Company's commitment for these operating leases for fiscal year 2005 is approximately $1,208,000.

## 13. Nuclear Insurance

Duke maintains liability, property and decontamination insurance coverage on its nuclear facilities, including Catawba. The Company has been advised by Duke that appropriate levels of primary and secondary coverage are maintained in accordance with applicable federal and state regulations.

The Company reimburses Duke for its pro rata share of the cost of such insurance. In addition, the Company will be responsible for its pro rata share of any retrospective premiums or other costs incurred by Duke in the event an accident occurs where liabilities exceed insurance coverages.

## 14. Related-Party Transactions

The Company conducted business transactions with the following organizations during the current and prior years as set forth below.

**New Horizon Electric Cooperative**
The Company leases office space and computer equipment from New Horizon, a related party. Costs paid to New Horizon pursuant to these agreements were approximately $690,000 and $1,118,000 during fiscal years 2004 and 2003, respectively. Also, New Horizon bills the Company on a monthly basis for power delivery expenses paid by New Horizon to Duke and South Carolina Electric and Gas ("SCE&G"). Costs paid to New Horizon pursuant to these agreements were approximately $6,273,000 and $4,713,000 for fiscal years 2004 and 2003, respectively. The Company was obligated under these agreements to New Horizon for approximately $600,000 and $685,000 as of December 31, 2004 and 2003, respectively.

In 2003, the Company also provided certain administrative services to New Horizon, and New Horizon reimbursed the Company for these services. Total payments received from New Horizon were approximately $633,000 during 2003 and are included in sales to nonmembers in the accompanying financial statements.

Effective January 1, 2004, all of the Company's employees were transferred to New Horizon. As a result, New Horizon provides certain administrative services for the Company. In 2004, the Company reimbursed New Horizon approximately $443,400 for administrative services.

Effective with the transfer of employees on January 1, 2004, New Horizon also provides dynamic scheduling and metering services to the Company for which the Company reimburses New Horizon. In 2004, the Company reimbursed New Horizon approximately $448,000 for dynamic scheduling and metering services.

**National Rural Utilities Cooperative Finance Corporation (CFC)**
The Company is a member of CFC, a national financial organization and, as explained in Note 6, has investment assets in CFC.

**Federated Rural Electric Insurance Exchange**
The Company is a shareholder of Federated (Note 6), and purchases its general property and liability coverage from this corporation. The Company purchased $53,435 and $79,000 of general property and liability coverage during 2004 and 2003, respectively.

**Electric Cooperatives of South Carolina, Inc. ("ECSC")**
As a member of ECSC, a statewide organization composed of electric cooperatives, the Company purchased approximately $1,250 and $1,600 of training materials in 2004 and 2003, respectively.

**Central Electric Power Cooperative, Inc.**
The Company purchased supplemental energy of approximately $73,966,000 and $67,180,000 pursuant to the wholesale power contract in 2004 and 2003, respectively. The Company was current on all obligations to Central as of December 31, 2004 and 2003.

## 15. Concentrations of Credit Risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist principally of cash and cash equivalents and consumer accounts receivable. Depository accounts of the Company were in institutions insured by the Federal Depository Insurance Corporation, and deposits did not exceed the insurance limits at December 31, 2004 and 2003. Concentrations of credit risk with respect to electric member accounts are increased due to the small customer base. However, management believes the associated credit risk is limited.

## 16. Subsequent Events

In June 2004, RUS issued a request for proposal ("RFP") for potential buyers to purchase the Company's ownership interest in Catawba. In response to the RFP, six bidders offered proposals to purchase the Company's ownership interest in Catawba. RUS is currently evaluating the proposals to determine which bidders it will enter into negotiations with regarding the sale of their ownership interest in Catawba.

The Company reached an agreement with RUS in November 2004, whereby it was agreed that the sale of Catawba shall occur on or before December 31, 2008, with a targeted sale date of September 30, 2008. Furthermore, the agreement provides that if Catawba has not been sold on or before December 31, 2008, then the Company shall deliver title to Catawba and the Company's rights in respect of the Decommissioning Trust Fund to RUS or any RUS designee by December 31, 2008.

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

# FORM 10-K

FOR ANNUAL AND TRANSITION REPORTS
PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2004 or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ________ to ________

Commission file number 1-4928

# DUKE ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| North Carolina<br>(State or other jurisdiction of incorporation or organization) | 56-0205520<br>(I.R.S. Employer Identification No.) |
| 526 South Church Street, Charlotte, North Carolina<br>(Address of principal executive offices) | 28202-1803<br>(Zip Code) |

704-594-6200
(Registrant's telephone number, including area code)

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

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Stock, without par value | New York Stock Exchange, Inc. |
| 6.375% Preferred Stock A, 1993 Series, par value $25 | New York Stock Exchange, Inc. |
| Preference Stock Purchase Rights | New York Stock Exchange, Inc. |

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

Title of class

Preferred Stock, par value $100

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☒ No ☐

| | |
|---|---|
| Estimated aggregate market value of the common equity held by nonaffiliates of the registrant at June 30, 2004 | $18,998,000,000 |
| Number of shares of Common Stock, without par value, outstanding at March 4, 2005 | 957,690,054 |

DOCUMENTS INCORPORATED BY REFERENCE:

The registrant is incorporating herein by reference certain sections of the proxy statement relating to the 2005 annual meeting of shareholders to provide information required by Part III, Items 10, 11, 12 and 14 of this annual report.

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# DUKE ENERGY CORPORATION FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2004



## SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Duke Energy Corporation's reports, filings and other public announcements may contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as "may," "will," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "potential," "plan," "forecast" and other similar words. Those statements represent Duke Energy's intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors. Many of those factors are outside Duke Energy's control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. Those factors include:

- State, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures, and affect the speed at and degree to which competition enters the electric and natural gas industries
- The outcomes of litigation and regulatory investigations, proceedings or inquiries
- Industrial, commercial and residential growth in Duke Energy's service territories
- 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, including any potential effects arising from terrorist attacks and any consequential hostilities or other hostilities
- 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, including Duke Energy's ability to obtain financing on favorable terms, which can be affected by various factors, including Duke Energy's credit ratings and general economic conditions
- Declines in the market prices of equity securities and resultant cash funding requirements for Duke Energy's defined benefit pension plans
- The level of creditworthiness of counterparties to Duke Energy's transactions
- The amount of collateral required to be posted from time to time in Duke Energy's transactions
- Growth in opportunities for Duke Energy's business units, including the timing and success of efforts to develop domestic and international power, pipeline, gathering, processing and other infrastructure projects
- Competition and regulatory limitations affecting the success of Duke Energy's divestiture plans, including the prices at which Duke Energy is able to sell its assets
- The performance of electric generation, pipeline and gas processing facilities
- The extent of success in connecting natural gas supplies to gathering and processing systems and in connecting and expanding gas and electric markets
- The effect of accounting pronouncements issued periodically by accounting standard-setting bodies and
- Conditions of the capital markets and equity markets during the periods covered by the forward-looking statements

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Duke Energy has described. Duke Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

## Item 1. Business.

### GENERAL

Duke Energy Corporation (collectively with its subsidiaries, Duke Energy) is a leading energy company located in the Americas with a real estate subsidiary. Duke Energy provides its services through the business units described below.

Duke Energy operates the following business units: Franchised Electric, Natural Gas Transmission, Field Services, Duke Energy North America (DENA), International Energy and Crescent Resources, LLC (Crescent). Duke Energy's chief operating decision maker regularly reviews financial information about each of these business units in deciding how to allocate resources and evaluate performance. The entities under each business unit have similar economic characteristics, services, production processes, distribution methods and regulatory concerns. All of the Duke Energy business units are considered reportable segments under Statement of Financial Accounting Standards (SFAS) No. 131, "Disclosures about Segments of an Enterprise and Related Information."

Franchised Electric generates, transmits, distributes and sells electricity in central and western North Carolina and western South Carolina. It conducts operations through Duke Power. These electric operations are subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC).

Natural Gas Transmission provides transportation and storage of natural gas for customers along the U.S. East Coast, the Southeast, and in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and natural gas processing services to customers in Western Canada. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission, LLC. Duke Energy Gas Transmission, LLC's natural gas transmission and storage operations in the U.S. are primarily subject to the FERC's and the U.S. Department of Transportation's (DOT's) rules and regulations, while natural gas gathering, processing, transmission, distribution and storage operations in Canada are primarily subject to the rules and regulations of the National Energy Board (NEB) and the Ontario Energy Board (OEB). Texas Eastern Transmission LP (Texas Eastern) is an indirect subsidiary of Natural Gas Transmission and was also a separate Securities and Exchange Commission (SEC) reporting entity. On December 15, 2004 Texas Eastern announced that it filed a Form 15 with the SEC to suspend its reporting obligations under the Securities Exchange Act of 1934. Texas Eastern is eligible to suspend its reporting obligation under the 1934 Act because it has fewer than 300 holders of record of any class of its securities.

Field Services gathers, compresses, treats, processes, transports, trades and markets, and stores natural gas; and fractionates, transports, trades and markets, and stores natural gas liquids (NGLs). It conducts operations primarily through Duke Energy Field Services, LLC (DEFS), which is approximately 30% owned by ConocoPhillips and approximately 70% owned by Duke Energy. Field Services gathers raw natural gas through gathering systems located in eight major natural gas producing regions: Permian Basin, Mid-Continent, ArkIaTex, Gulf Coast, South, Central, Rocky Mountains and Western Canada. DEFS, which previously was a separate SEC reporting entity, announced January 31, 2005 that it filed a Form 15 with the SEC to suspend its reporting obligations under the Securities Exchange Act of 1934. DEFS is eligible to suspend its reporting obligations under the 1934 Act because it has fewer than 300 holders of record of any class of its securities.

In February 2005, Duke Energy executed an agreement with ConocoPhillips whereby Duke Energy has agreed to transfer a 19.7 percent interest in DEFS to ConocoPhillips for direct and indirect monetary and non-monetary consideration of approximately $1.1 billion. Upon completion of this transaction, DEFS will be owned 50% by Duke Energy and 50% by ConocoPhillips. As a result, Duke Energy expects to account for its investment in DEFS using the equity method subsequent to closing of the transaction. This transaction, which is subject to customary U.S. and Canadian regulatory approvals, is expected to close in the latter half of 2005. Additionally, in February 2005, DEFS sold its wholly-owned subsidiary, Texas Eastern Products Pipeline Company LLC (TEPPCO), the general partner of TEPPCO Partners L.P., for approximately $1.1 billion and Duke Energy sold its limited partner interest in TEPPCO Partners, L.P. for approximately $100 million, in each case to Enterprise GP Holdings L.P. (EPCO), an unrelated third party. TEPPCO Partners, L.P. is a publicly traded master limited partnership which owns one of the largest common-carrier pipelines of refined petroleum products and liquefied petroleum gases in the United States, as well as natural gas gathering systems, petrochemical and NGL pipelines, and is engaged in crude oil transportation, storage, gathering and marketing. TEPPCO is responsible for the management and operations of TEPPCO Partners, L.P.

DENA operates and manages power plants and markets electric power and natural gas related to these plants and other contractual positions. DENA conducts business throughout the U.S. and Canada through Duke Energy North America, LLC and its 100% owned affiliates Duke Energy Marketing America, LLC and Duke Energy Marketing Canada Corp. DENA also participates in Duke Energy Trading and Marketing, LLC (DETM). DETM is 40% owned by Exxon Mobil Corporation and 60% owned by Duke Energy.

International Energy operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U.S. and Canada. It conducts operations primarily through Duke Energy International, LLC (DEI) and its activities target power generation in Latin America. Additionally, International Energy owns an equity investment in National Methanol Company, located in Saudi Arabia, which is a leading regional producer of methanol and methyl tertiary butyl ether (MTBE).

Crescent develops and manages high-quality commercial, residential and multi-family real estate projects primarily in the southeastern and southwestern United States. Some of these projects are developed and managed through joint ventures. Crescent also manages "legacy" land holdings in North and South Carolina.

The remainder of Duke Energy's operations is presented as "Other". While it is not considered a business segment, Other primarily includes certain unallocated corporate costs, DukeNet Communications, LLC (DukeNet), Duke Energy Merchants, LLC (DEM), Bison Insurance Company Limited (Bison), Duke Energy's wholly owned, captive insurance subsidiary, and Duke Energy's 50% interest in Duke/Fluor Daniel (D/FD). DukeNet develops, owns and operates a fiber optic communications network primarily in the Carolinas, serving wireless, local and long-distance communications companies, Internet service providers and other businesses and organizations. During 2003, Duke Energy determined that it would exit the refined products business at DEM in an orderly manner, and continues to unwind its portfolio of contracts. As of December 31, 2004, DEM had exited the majority of its business. Bison's principle activities, as a captive insurance entity, include the insurance and reinsurance of various business risks and losses, such as workers compensation, property, business interruption and general liability of subsidiaries and affiliates of Duke Energy. Bison also participates in reinsurance activities with certain third parties, on a limited basis. D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation. During 2003, Duke Energy and Fluor Corporation announced that they would dissolve the D/FD partnership. The D/FD partners adopted a plan for an orderly wind-down of the business which is expected to be completed by December 2005. Previously, D/FD provided comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide. During 2003, Duke Energy decided to exit the merchant finance business conducted by Duke Capital Partners, LLC (DCP). DCP had been previously included in Other. At December 31, 2004 Duke Energy had exited the merchant finance business, and all of the results of operations for DCP have been classified as discontinued operations in the accompanying Consolidated Statements of Operations.

Duke Energy is a North Carolina corporation. Its principal executive offices are located at 526 South Church Street, Charlotte, North Carolina 28202-1803. The telephone number is 704-594-6200. Duke Energy electronically files reports with the SEC, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxies and amendments to such reports. The public may read and copy any materials that Duke Energy files with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at *http://www.sec.gov*. Additionally, information about Duke Energy, including its reports filed with the SEC, is available through Duke Energy's web site at *http://www.duke-energy.com*. Such reports are accessible at no charge through Duke Energy's web site and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC.

Terms used to describe Duke Energy's business are defined below.

**Accrual Model of Accounting (Accrual Model).** An accounting term used by Duke Energy to refer to contracts for which there is generally no recognition in the Consolidated Statements of Operations for any changes in fair value until the service is provided or the associated delivery period occurs or there is hedge ineffectiveness. As discussed further in Note 1 to the Consolidated Financial Statements, this term is applied to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, as well as to non-derivative contracts used for commodity risk management purposes. As this term is not explicitly defined within U.S. Generally Accepted Accounting Principles (GAAP), Duke Energy's application of this term could differ from that of other companies.

**Allowance for Funds Used During Construction (AFUDC).** A non-cash accounting convention of regulatory utilities that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

**British Thermal Unit (Btu).** A standard unit for measuring thermal energy or heat commonly used as a gauge for the energy content of natural gas and other fuels.

**Cubic Foot (cf).** The most common unit of measurement of gas volume; the amount of natural gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor.

**Decommissioning.** The process of closing down a nuclear facility and reducing the residual radioactivity to a level that permits the release of the property and termination of the license. Nuclear power plants are required by the Nuclear Regulatory Commission (NRC) to set aside funds for their decommissioning costs during operation.

**Derivative.** A financial instrument or contract in which its price is based on the value of underlying securities, equity indices, debt instruments, commodities or other benchmarks or variables. Often used to hedge risk, derivatives involve the trading of rights or obligations, but not the direct transfer of property. Gains or losses on derivatives are often settled on a net basis.

**Distribution.** The system of lines, transformers, switches and mains that connect electric and natural gas transmission systems to customers.

**Duke Capital LLC (Duke Capital).** Duke Capital LLC (formerly known as Duke Capital Corporation), a wholly owned subsidiary of Duke Energy that provides financing and credit enhancement services for its subsidiaries.

**Energy Marketing.** Identification and execution of physical energy related transactions, generally with customized provisions to meet the needs of the customer or supplier, throughout the supply chain.

**Environmental Protection Agency (EPA).** The U.S. agency that is responsible for researching and setting national standards for a variety of environmental programs, and delegates to states the responsibility for issuing permits and for monitoring and enforcing compliance.

**Federal Energy Regulatory Commission (FERC).** The U.S. agency that regulates the transportation of electricity and natural gas in interstate commerce and authorizes the buying and selling of energy commodities at market-based rates.

**Forward Contract.** A contract in which the buyer is obligated to take delivery, and the seller is obligated to deliver a specified amount of a commodity with a predetermined price formula on a specified future date, at which time payment is due in full.

**Fractionation/Fractionate.** The process of separating liquid hydrocarbons from natural gas into propane, butane, ethane and other related products.

**Futures Contract.** A contract, usually exchange traded, in which the buyer is obligated to take delivery and the seller is obligated to deliver a fixed amount of a commodity at a predetermined price on a specified future date.

**Gathering System.** Pipeline, processing and related facilities that access production and other sources of natural gas supplies for delivery to mainline transmission systems.

**Generation.** The process of transforming other forms of energy, such as nuclear or fossil fuels, into electricity. Also, the amount of electric energy produced, expressed in megawatt-hours.

**Independent System Operator (ISO).** An entity that acts as the transmission provider for a regional transmission system, providing customers access to the system and clearing all bilateral contract requests for use of the electric transmission system. An ISO also shares responsibility for maintaining bulk electric system reliability.

**Light-off Fuel.** Fuel oil used to light the coal prior to generating electricity.

**Liquefied Natural Gas (LNG).** Natural gas that has been converted to a liquid by cooling it to minus 260 degrees Fahrenheit.

**Liquidity.** The ease with which assets or products can be traded without dramatically altering the current market price.

**Local Distribution Company (LDC).** A company that obtains the major portion of its revenues from the operations of a retail distribution system for the delivery of electricity or gas for ultimate consumption.

**Logistics & Optimization.** The act of maximizing returns from physical positions through arbitrage, especially on contractual assets such as storage, transportation, generation and transmission.

**Mark-to-Market Model of Accounting (MTM Model).** An accounting term used by Duke Energy to refer to derivative contracts for which an asset or liability is recognized at fair value and the change in the fair value of that asset or liability is recognized in the Consolidated Statements of Operations. As discussed further in Note 1 to the Consolidated Financial Statements, this term is applied to trading and undesignated non-trading derivative contracts. As this term is not explicitly defined within U.S. GAAP, Duke Energy's application of this term could differ from that of other companies.

**Natural Gas.** A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

**Natural Gas Liquids (NGLs).** Liquid hydrocarbons extracted during the processing of natural gas. Principal commercial NGLs include butanes, propane, natural gasoline and ethane.

**No-notice Bundled Service.** A pipeline delivery service which allows customers to receive or deliver gas on demand without making prior nominations to meet service needs and without paying daily balancing and scheduling penalties.

**Origination.** Identification and execution of physical energy related transactions, generally with customized provisions to meet the needs of the customer or supplier, throughout the supply chain.

**Option.** A contract that gives the buyer a right but not the obligation to purchase or sell an underlying asset at a specified price at a specified time.

**Peak Load.** The amount of electricity required during periods of highest demand. Peak periods fluctuate by season, generally occurring in the morning hours in winter and in late afternoon during the summer.

**Portfolio.** A collection of assets, liabilities, transactions, or trades.

**Regional Transmission Organization (RTO).** An independent entity which is established to have "functional control" over utilities' transmission systems, in order to expedite transmission of electricity. RTO's typically operate markets within their territories.

**Reliability Must Run.** Generation that an ISO determines is required to be on-line to meet applicable reliability criteria requirements.

**Residue Gas.** Gas remaining after the processing of natural gas.

**Spark Spread.** The difference between the value of electricity and the value of the gas required to generate the electricity at a specified heat rate.

**Swap.** A contract to exchange cash flows in the future according to a prearranged formula.

**Throughput.** The amount of natural gas or NGLs transported through a pipeline system.

**Tolling.** Arrangement whereby a buyer provides fuel to a power generator and receives generated power in return for a specified fee.

**Transmission System (Electric).** An interconnected group of electric transmission lines and related equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over a distribution system to customers, or for delivery to other electric transmission systems.

**Transmission System (Natural Gas).** An interconnected group of natural gas pipelines and associated facilities for transporting natural gas in bulk between points of supply and delivery points to industrial customers, LDCs, or for delivery to other natural gas transmission systems.

**Volatility.** An annualized measure of the fluctuation in the price of an energy contract.

**Watt.** A measure of power production or usage equal to one joule per second.

The following sections describe the business and operations of each of Duke Energy's business segments. (For more information on the operating outlook of Duke Energy and its segments, see "Management's Discussion and Analysis of Results of Operations and Financial Condition, Introduction—Overview of Business Strategy and Economic Factors for Duke Energy's Business". For financial information on Duke Energy's business segments, see Note 3 to the Consolidated Financial Statements, "Business Segments.")

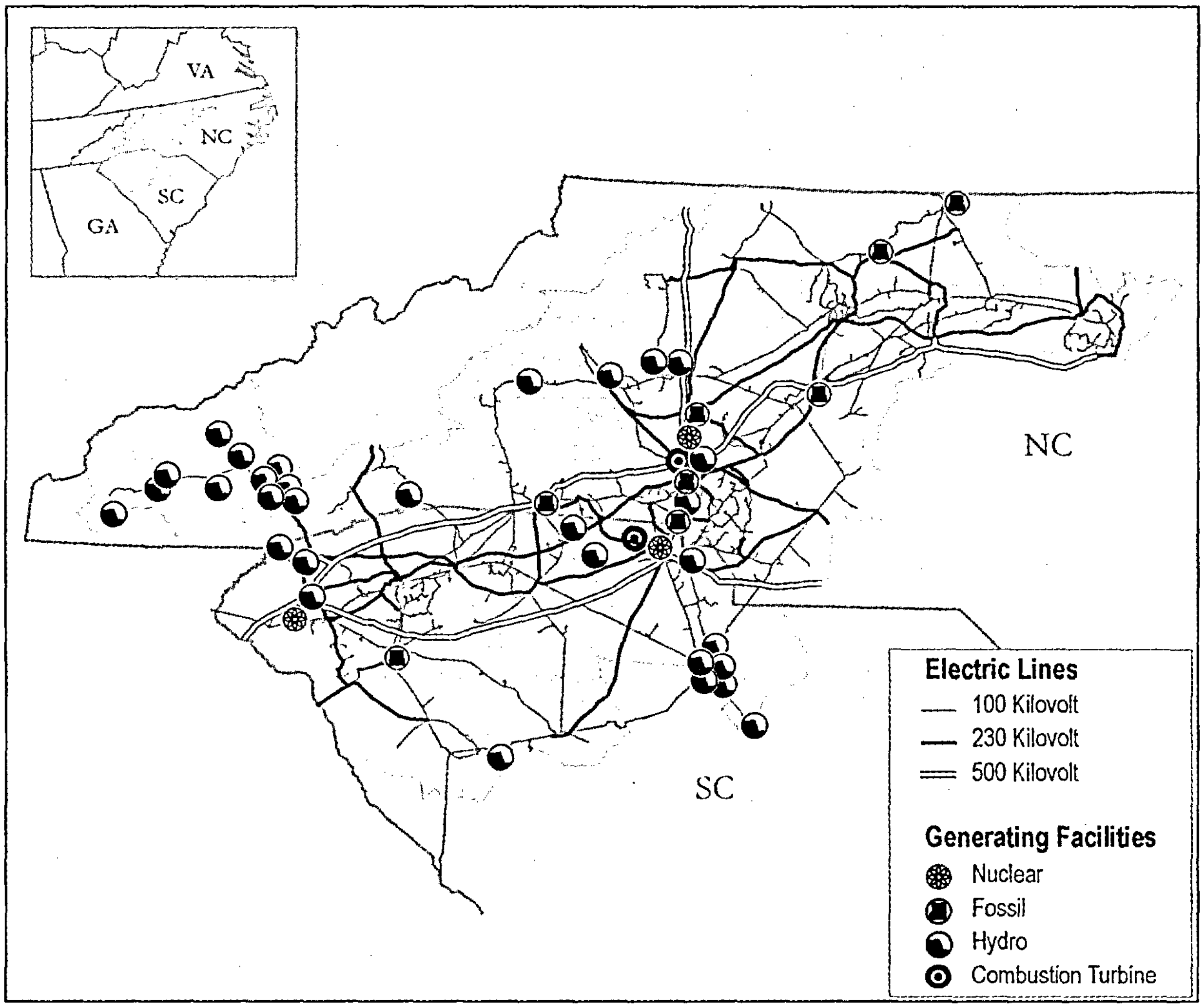
## FRANCHISED ELECTRIC

### Service Area and Customers

Franchised Electric generates, transmits, distributes and sells electricity. It conducts operations through Duke Power. Its service area covers about 22,000 square miles with an estimated population of 5.9 million in central and western North Carolina and western South Carolina. Franchised Electric supplies electric service to approximately 2.2 million residential, commercial and industrial customers over 94,000 miles of distribution lines and a 13,000-mile transmission system. Electricity is also sold wholesale to incorporated municipalities and to public and private utilities. In addition, municipal and cooperative customers who purchased portions of the Catawba Nuclear Station may also buy power from a variety of suppliers including Franchised Electric, through contractual agreements. (For more information on the Catawba Nuclear Station joint ownership, see Note 5 to the Consolidated Financial Statements, "Joint Ownership of Generating Facilities.")

Industrial and commercial development in Franchised Electric's service area is highly diversified. The textile industry, machinery and equipment manufacturing, and chemical industries are of major significance to the area's economy. Other industries operating in the area include rubber and plastic products, paper and related products, and other manufacturing and service businesses. The textile industry, while in decline, is the largest industry served by Franchised Electric and accounted for approximately $293 million of Franchised Electric's revenues for 2004, representing 6% of total electric revenues and 28% of industrial revenues. In 2004, Franchised Electric implemented business development strategies to leverage the competitive advantages of North Carolina and South Carolina to attract pharmaceutical, biotechnology, plastics, medical equipment and other industries.

Franchised Electric's costs and revenues are influenced by seasonal patterns. Peak sales occur during the summer and winter months, resulting in higher revenue and cash flows during those periods. By contrast, fewer sales occur during the spring and fall allowing for scheduled plant maintenance during those periods.




**Energy Capacity and Resources**

Electric energy for Franchised Electric's customers is generated by three nuclear generating stations with a combined net capacity of 5,020 megawatts (MW) (including Duke Energy's 12.5% ownership in the Catawba Nuclear Station), eight coal-fired stations with a combined capacity of 7,754 MW, 31 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 2,810 MW and seven combustion turbine stations with a combined capacity of 2,447 MW. Energy and capacity are also supplied through contracts with other generators and purchased on the open market. Franchised Electric has interconnections and arrangements with its neighboring utilities to facilitate planning, emergency assistance, sale and purchase of capacity and energy, and reliability of power supply. Franchised Electric expects that current generation capabilities plus additional construction, purchased power contracts and open market purchases will meet customers' energy needs in the future.

Franchised Electric's generation portfolio is a balanced mix of energy resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet its obligation to serve native-load customers. All options including owned generation resources and purchased power opportunities are continually evaluated on a real-time basis to select and dispatch the lowest-cost resources available to meet system load requirements. The vast majority of customer energy needs are met by Franchised Electric's large, low-energy-production-cost nuclear and coal-fired generating units that operate almost continuously (or at baseload levels). In 2004, approximately 98% of the total generated energy came from Franchised Electric's low-cost, efficient nuclear and coal units (45.9% nuclear and 52.2% coal). The remainder of energy needs was supplied by hydroelectric and combustion-turbine generation or economical purchases from the wholesale market.

*Hydroelectric (both conventional and pumped storage) and gas/oil combustion-turbine stations operate during the peak-hour load* periods (at peaking levels) when customer loads are rapidly changing. Combustion turbines produce energy at higher production costs than either nuclear or coal, but are less expensive to build and maintain, and can be rapidly started or stopped as needed to meet changing customer loads. Hydroelectric units produce low-cost energy, but their operations are limited by the availability of water flow. Since hydroelectric units can also be rapidly started or stopped, they are also used in periods of rapidly changing customer loads so that system operators can match loads with the appropriate amount of generation.

Franchised Electric's two major pumped-storage hydroelectric facilities offer the added flexibility of using low-cost off-peak energy to pump water that will be stored for later generation use during times of higher-cost on-peak generation periods. These plants allow Franchised Electric to maximize the value spreads between different high- and low-cost generation periods.

### Fuel Supply

Franchised Electric relies principally on coal and nuclear fuel for its generation of electric energy. The following table lists Franchised Electric's sources of power and fuel costs for the three years ended December 31, 2004.

| | Generation by Source (Percent) | | | Cost of Delivered Fuel per Net Kilowatt-hour Generated (Cents) | | |
|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| Coal | 52.2 | 50.7 | 51.2 | 1.84 | 1.59 | 1.54 |
| Nuclear(a) | 45.9 | 46.7 | 48.3 | 0.41 | 0.42 | 0.42 |
| Oil and gas(b) | 0.2 | 0.1 | 0.1 | 16.79 | 15.52 | 11.89 |
| All fuels (cost based on weighted average)(a) | 98.3 | 97.5 | 99.6 | 1.20 | 1.05 | 1.01 |
| Hydroelectric(c) | 1.7 | 2.5 | 0.4 | | | |
| | 100.0 | 100.0 | 100.0 | | | |

(a) Statistics related to nuclear generation and all fuels reflect Franchised Electric's 12.5% ownership interest in the Catawba Nuclear Station.

(b) *Cost statistics include amounts for light-off fuel at Franchised Electric's coal-fired stations.*

(c) Generating figures are net of output required to replenish pumped storage facilities during off-peak periods.

***Coal.*** *Franchised Electric meets its coal demand through purchase supply contracts and spot agreements.* Large amounts of coal are obtained under supply contracts with mining operators who mine both underground and at the surface. Franchised Electric has an adequate supply of coal to fuel its current operations. Expiration dates for its supply contracts, which have price adjustment provisions, range from 2005 to 2007. Franchised Electric expects to renew these contracts or enter into similar contracts with other suppliers for the quantities and quality of coal required, though prices will fluctuate over time. The coal purchased under these contracts is produced from mines in eastern Kentucky, southern West Virginia and southwestern Virginia. Franchised Electric uses spot-market purchases to meet coal requirements not met by supply contracts. During 2004, Franchised Electric experienced coal delivery difficulties from railroads that deliver coal to its power plants. Coal supplies were sufficient to fuel generation needed to meet the demand of retail customers but were limited for wholesale sales. Coal deliveries have since improved and Franchised Electric expects to have increased wholesale opportunities as coal inventories increase.

The average sulfur content of coal purchased by Franchised Electric is approximately 1%. Coupled with the use of available sulfur dioxide emission allowances on the open market, this satisfies the current emission limitation for sulfur dioxide for existing facilities.

***Nuclear.*** Developing nuclear generating fuel generally involves the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride gas, enrichment of that gas, and then the fabrication of the enriched uranium hexafluoride into usable fuel assemblies.

Franchised Electric has contracted for uranium materials and services required to fuel Oconee, McGuire and Catawba Nuclear Stations. Uranium concentrates, conversion services and enrichment services are primarily met through a diversified portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. Franchised Electric staggers its contracting so that its portfolio of long-term contracts covers the majority of its fuel requirements at Oconee, McGuire and Catawba in the near term, but so that its level of coverage decreases each year into the future. Due to the technical complexities of changing suppliers of fuel fabrication services, Franchised Electric generally sole sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Based on current projections, Franchised Electric's existing portfolio of contracts will meet the requirements of Oconee, McGuire and Catawba Nuclear Stations through the following years:

| Nuclear Station | Uranium Material | Conversion Service | Enrichment Service | Fabrication Service |
|---|---|---|---|---|
| Oconee | 2007 | 2007 | 2007 | 2006 |
| McGuire | 2007 | 2007 | 2007 | 2009 |
| Catawba | 2007 | 2007 | 2007 | 2009 |

After the years indicated above, a portion of the fuel requirements at Oconee, McGuire and Catawba are covered by long-term contracts. For requirements not covered under long-term contracts, Duke Energy believes it will be able to renew contracts as they expire, or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with uranium spot market purchases.

Duke Power has entered into a contract under which it has agreed to prepare the McGuire and Catawba nuclear reactors for use of mixed-oxide fuel and to purchase mixed-oxide fuel for use in such reactors. Mixed-oxide fuel will be fabricated by Duke COGEMA Stone & Webster, LLC from the U.S. government's excess plutonium from its nuclear weapons programs and is similar to conventional uranium fuel. Before using the fuel, Duke Power must apply for and obtain amendments to the facilities' operating licenses from the NRC. On March 3, 2005, the NRC issued amendments to Catawba Nuclear Station's operating licenses to allow the receipt and use of four mixed oxide fuel lead assemblies. (See Note 18 to the Consolidated Financial Statements, "Guarantees and Indemnifications," for additional information.)

### Inventory

Generation of electricity is capital-intensive. Franchised Electric must maintain an adequate stock of fuel, materials and supplies in order to ensure continuous operation of generating facilities and reliable delivery to customers. As of December 31, 2004, the inventory balance for Franchised Electric was approximately $405 million. (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for additional information.)

### Insurance and Decommissioning

Duke Energy owns and operates McGuire and Oconee Nuclear Stations and operates and has a partial ownership interest in Catawba Nuclear Station. McGuire and Catawba have two nuclear reactors each and Oconee has three. Nuclear insurance includes: liability coverage; property, decontamination and premature decommissioning coverage; and business interruption and/or extra expense coverage. The other joint owners of the Catawba Nuclear Station reimburse Duke Energy for certain expenses associated with nuclear insurance premiums. The Price-Anderson Act requires Duke Energy to insure against public liability claims resulting from nuclear incidents to the full limit of liability, approximately $10.8 billion. (See Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies—Nuclear Insurance," for more information.)

In October 2004, Duke Power filed the results of a funding study for nuclear decommissioning costs with the NCUC, and in December 2004, Duke Power notified the PSCSC of the results of the funding study (filing of the study is not required by the PSCSC). The funding study, which was based on the updated nuclear decommissioning cost estimate and renewal of the nuclear operating licenses, indicates that an annual cash contribution to the Nuclear Decommissioning Trust Funds (NDTF) of $48 million (compared to a current level of approximately $70 million), which are invested in debt and equity securities as discussed in Note 7 to the Consolidated Financial Statements, "Asset Retirement Obligations," is now required to fully cover the estimated nuclear decommissioning costs. Duke Power anticipates that the NCUC will rule later in 2005 on whether any change in Duke Power's decommissioning expense is necessary.

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $2.3 billion in 2003 dollars, based on a decommissioning study completed in 2004. This includes costs related to Duke Energy's 12.5% ownership in Catawba Nuclear Station. The other joint owners of Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. The previous study, conducted in 1999, estimated a decommissioning cost of $1.9 billion ($2.2 billion in 2003 dollars at 3% inflation). The estimated increase is due primarily to inflation and cost increases for the size of the organization needed to manage the decommissioning project (based on current industry experience at facilities undergoing decommissioning). Both the NCUC and the PSCSC have allowed Duke Energy to recover estimated decommissioning costs through retail rates over the expected remaining service periods of Duke Energy's nuclear stations. Management believes that the decommissioning costs being recovered through rates, when coupled with expected fund earnings, are sufficient to provide for the cost of decommissioning.

After spent fuel is removed from a nuclear reactor, it is cooled in a spent-fuel pool at the nuclear station. Under provisions of the Nuclear Waste Policy Act of 1982, Duke Energy has contracted with the U.S. Department of Energy (DOE) for the disposal of spent nuclear fuel. The DOE failed to begin accepting spent nuclear fuel on January 31, 1998, the date specified by the Nuclear Waste Policy Act and in Duke Energy's contract with the DOE. In 1998, Duke Energy filed a claim with the U.S. Court of Federal Claims against the DOE related to the DOE's failure to accept commercial spent nuclear fuel by the required date. Damages claimed in the lawsuit are based upon Duke Energy's costs incurred as a result of the DOE's partial material breach of its contract, including the cost of securing additional spent fuel storage capacity. Duke Energy will continue to safely manage its spent nuclear fuel until the DOE accepts it. Payments made to the DOE for disposal costs are based on nuclear output and are included in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power.

Duke Energy has experienced numerous claims relating to damages for personal injuries alleged to have arisen from the exposure to or use of asbestos in connection with construction and maintenance activities conducted by Duke Power on its electric generation plants during the 1960s and 1970s. Duke Energy has third-party insurance to cover losses related to these asbestos-related injuries and damages above a certain aggregate deductible. This insurance policy, including the policy deductible, provides for coverage to Duke Energy up to an aggregate of $1.6 billion. Probable insurance recoveries related to this policy are classified in the Consolidated Balance Sheets as Other within noncurrent assets. Amounts recognized as reserves in the Consolidated Balance Sheets are classified in Other Deferred Credits and Other Liabilities and Other Current Liabilities and are based upon Duke Energy's best estimate of the probable liability for future asbestos claims. These reserves are based upon current estimates and are subject to uncertainty. Factors such as the frequency and magnitude of future claims could change the current estimates of the related reserves and claims for recoveries reflected in the accompanying Consolidated Financial Statements. However, management of Duke Energy does not currently anticipate that any changes to these estimates will have any material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

**Competition**

Duke Energy continues to monitor electric industry restructuring; however, movement toward retail deregulation has virtually stopped.

Franchised Electric competes in some areas with government-owned power systems, municipally owned electric systems, rural electric cooperatives and other private utilities. By statute, the NCUC and the PSCSC assign all service areas outside municipalities in North Carolina and South Carolina to regulated electric utilities and rural electric cooperatives. Substantially all of the territory comprising Franchised Electric's service area has been assigned in this manner. In unassigned areas, Franchised Electric's business remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina, competition continues between municipalities and other electric suppliers outside the municipalities' corporate limits, subject to the regulation of the PSCSC. Franchised Electric also competes with other utilities and marketers in the wholesale electric business. In addition, Franchised Electric continues to compete with natural gas providers.

**Regulation**

The NCUC and the PSCSC approve rates for retail electric sales within their respective states. The FERC approves Franchised Electric's rates for electric sales to regulated wholesale customers. (For more information on rate matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters—Franchised Electric.") The FERC, the NCUC and the PSCSC also have authority over the construction and operation of Franchised Electric's facilities. Certificates of public convenience and necessity issued by the FERC, the NCUC and the PSCSC authorize Franchised Electric to construct and operate its electric facilities, and to sell electricity to retail and wholesale customers. Prior approval from the NCUC and the PSCSC is required for Duke Energy to issue securities.

NCUC, PSCSC and FERC regulations govern access to regulated electric customer and other data by non-regulated entities, and services provided between regulated and non-regulated energy affiliates. These regulations affect the activities of non-regulated affiliates with Franchised Electric.

The Energy Policy Act of 1992 and subsequent rulemaking by FERC initiated an opening of wholesale energy market to competition. Open-access transmission for wholesale customers, as defined by FERC rules, provides energy suppliers, including Franchised Electric, with opportunities to sell and deliver capacity and energy at market-based prices. Franchised Electric is also able to purchase at market rates a portion of its capacity and energy requirements resulting in lower overall costs to customers. Open access also provides wholesale customers geographically located in Franchised Electric's control area with competitive opportunities to seek other suppliers for their capacity and energy requirements.

The FERC continues to advocate for independent functioning of transmission grids, including through a variety of rulemakings and policy proposals, and has supported the development of Regional Transmission Organizations (RTOs) across the U.S. As a result of these rulemakings, Duke Power and the franchised electric units of Carolina Power & Light Company (now Progress Energy Carolinas) and South Carolina Electric & Gas Company, planned to establish GridSouth Transco, LLC (GridSouth), as an RTO responsible for the functional control of the companies' combined transmission systems. As of December 31, 2003, Duke Energy had invested $41 million in GridSouth, including carrying costs calculated through December 31, 2002. This amount is included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets. Due to regulatory uncertainty, development of the GridSouth implementation project was suspended in 2002. Duke Energy continues to examine options in support of the FERC's transmission policy goals. Management expects it will recover its investment in GridSouth.

Franchised Electric is subject to the NRC jurisdiction for the design, construction and operation of its nuclear generating facilities. In 2000, the NRC renewed the operating license for Duke Energy's three Oconee nuclear units through 2033 and 2034. In 2003, the NRC renewed the operating licenses for all units at Duke Energy's McGuire and Catawba stations. The two McGuire units are licensed through 2041 and 2043, while the two Catawba units are licensed through 2043. Franchised Electric's hydroelectric generating facilities are licensed by the FERC under Part I of the Federal Power Act, with license terms expiring from 2005 to 2036. The FERC has authority to extend hydroelectric generating licenses. Other hydroelectric facilities whose licenses expire between 2005 and 2008 are in various stages of relicensing.

Franchised Electric is subject to the jurisdiction of the EPA and state environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

**NATURAL GAS TRANSMISSION**

Natural Gas Transmission provides transportation and storage of natural gas for customers along the U.S. East Coast, the Southeast, and in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and gas processing services to customers in western Canada. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission LLC.

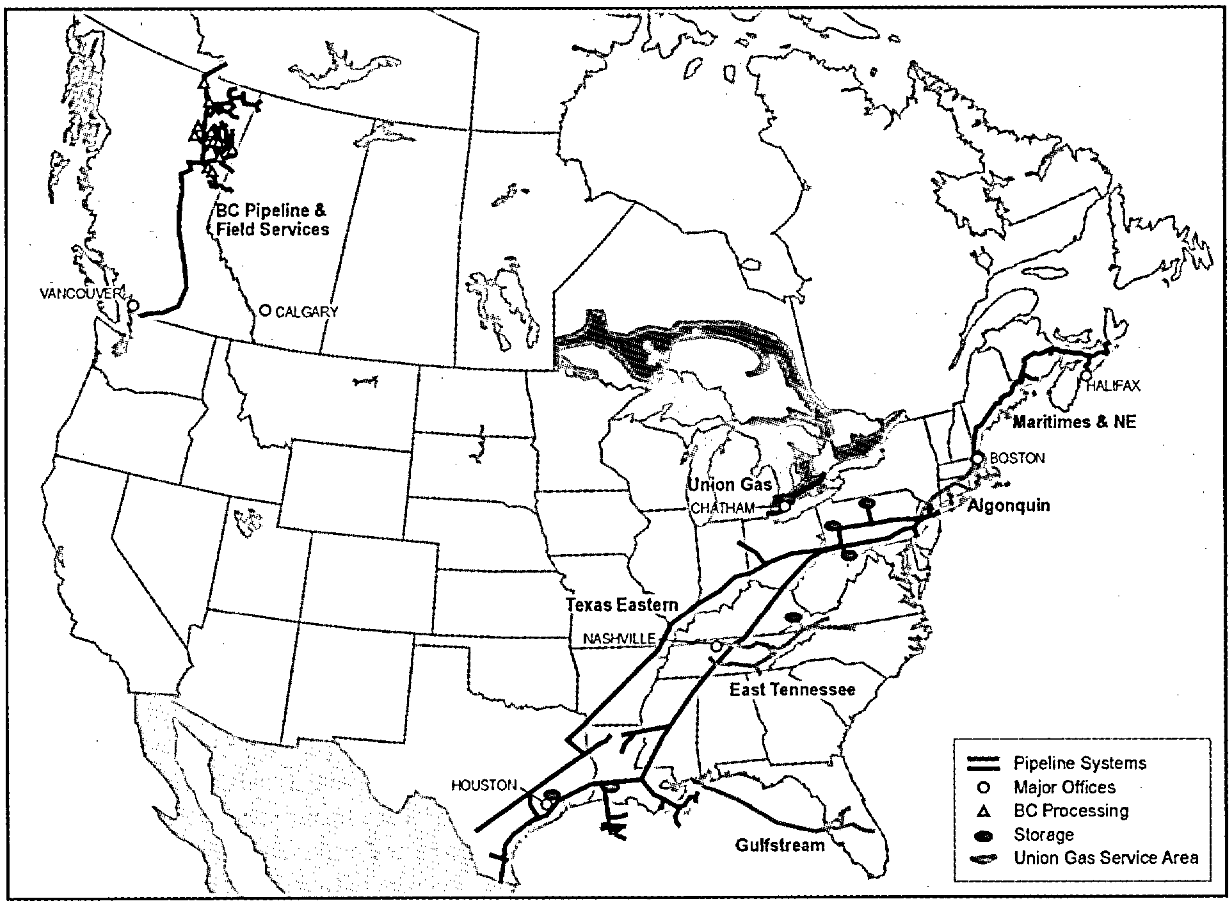
For 2004, Natural Gas Transmission's proportional throughput for its pipelines totaled 3,332 trillion British thermal units (TBtu), compared to 3,362 TBtu in 2003. This includes throughput on Natural Gas Transmission's wholly owned U.S. and Canadian pipelines and its proportional share of throughput on pipelines that are not wholly owned. A majority of Natural Gas Transmission's contracted transportation volumes are under long-term firm service agreements with LDC customers in the pipelines' market areas. Firm transportation services are also provided to gas marketers, producers, other pipelines, electric power generators and a variety of end-users. In addition, the pipelines provide both firm and interruptible transportation to various customers on a short-term or seasonal basis. Demand on Natural Gas Transmission's pipeline systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth calendar quarters. Natural Gas Transmission's pipeline systems consist of more than 17,500 miles of transmission pipelines. The pipeline systems receive natural gas from major North American producing regions for delivery to markets primarily in the Mid-Atlantic, New England and Southeastern states, Ontario, Alberta, and British Columbia. (For detailed descriptions of Natural Gas Transmission's pipeline systems, see "Properties—Natural Gas Transmission".)

Natural Gas Transmission, through Market Hub Partners (MHP), wholly owns natural gas salt cavern storage facilities in southeast Texas and Louisiana. MHP markets natural gas storage services to pipelines, LDCs, producers, end users and natural gas marketers. Texas Eastern and East Tennessee Natural Gas, LLC (ETNG) also provide firm and interruptible open-access storage services. Storage is offered as a stand-alone unbundled service or as part of a no-notice bundled service with transportation.

Natural Gas Transmission provides retail distribution services through its subsidiary, Union Gas Limited (Union Gas). Union Gas owns and operates natural gas transmission, distribution and storage facilities in Ontario. Union Gas distributes natural gas to approximately 1.2 million residential, commercial and industrial customers in northern, southwestern and eastern Ontario and provides storage, transportation and related services to utilities and other industry participants in the gas markets of Ontario, Quebec and the central and eastern United States.

Natural Gas Transmission's processing plants in western Canada provide services primarily to natural gas producers to remove impurities from the raw gas stream including water, carbon dioxide, hydrogen sulphide and other substances. In addition, where required the facilities remove liquid hydrocarbons including propane, butane and pentanes plus. Natural Gas Transmission receives a volume based fee for these processing services under contracts that have an average duration of one to three years.

In February 2005, Duke Energy executed an agreement with ConocoPhillips whereby Duke Energy has agreed to transfer a 19.7% interest in DEFS to ConocoPhillips for direct and indirect monetary and non-monetary consideration of approximately $1.1 billion. Upon closing of this transaction, Natural Gas Transmission expects to receive Canadian assets being transferred from DEFS and assets in Alberta and Saskatchewan, Canada from ConocoPhillips, which will allow Natural Gas Transmission to continue building scope, scale and diversity within its Canadian asset portfolio.




### Competition

Natural Gas Transmission's transportation, storage and gas gathering and processing businesses compete with other pipeline and storage facilities that serve its market areas in the transportation, processing and storage of natural gas. The principal elements of competition are rates, terms of service, and flexibility and reliability of service.

Natural gas competes with other forms of energy available to Natural Gas Transmission's customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors affect the demand for natural gas in the areas served by Natural Gas Transmission.

Union Gas' distribution sales to industrial customers are affected by weather, economic conditions and the price of competitive energy sources. Most of Union Gas' industrial and commercial customers, and a portion of residential customers, purchase their natural gas supply directly from suppliers or marketers. Because Union Gas earns income from the distribution of natural gas and not the sale of the natural gas commodity, the gas distribution margin is not affected by the source of the customer's gas supply.

### Regulation

Most of Natural Gas Transmission's pipeline and storage operations in the U.S. are regulated by the FERC. The FERC has authority to regulate rates and charges for natural gas transported or stored for U.S. interstate commerce or sold by a natural gas company via interstate commerce for resale. (For more information on rate matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters—Natural Gas Transmission.") The FERC also has authority over the construction and operation of U.S. pipelines and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. In addition, certain operations are subject to state regulatory commissions.

FERC regulations restrict access to U.S. interstate pipeline natural gas transmission customer data by marketing and other energy affiliates, and place certain conditions on services provided by the U.S. interstate pipelines to their affiliated gas marketing entities. These regulations affect the activities of non-regulated affiliates with Natural Gas Transmission.

The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, which remain subject to the FERC's jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of these regulatory changes is to promote competition among the various sectors of the natural gas industry.

Natural Gas Transmission's U.S. operations are subject to the jurisdiction of the EPA and state environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.) Natural Gas Transmission's interstate natural gas pipelines are subject to the regulations of the DOT concerning pipeline safety. DOT regulations have incorporated certain provisions of the Natural Gas Pipeline Safety Act of 1968 (and subsequent acts). The DOT developed new regulations, effective February 14, 2004, that establish mandatory inspections for all natural gas transmission pipelines in high-consequence areas within 10 years. These regulations require pipeline operators to implement integrity management programs, including more frequent inspections, and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to life and property. Management believes that compliance with these DOT regulations for Natural Gas Transmission will not have a material adverse effect on the consolidated results of operations, cash flows or financial position of Duke Energy.

The natural gas gathering, processing, transmission, storage and distribution operations in Canada are subject to regulation by the NEB and provincial agencies in Canada, such as the OEB. These agencies have authorization similar to the FERC for regulating rates, regulating the operations of facilities and construction of any additional facilities.

**FIELD SERVICES**

Field Services gathers, compresses, treats, processes, transports, trades and markets, and stores natural gas; and fractionates, transports, trades and markets, and stores NGLs. It conducts operations primarily through DEFS, which is approximately 30% owned by ConocoPhillips and approximately 70% owned by Duke Energy. In February 2005, Duke Energy executed an agreement with ConocoPhillips whereby Duke Energy has agreed to transfer a 19.7% interest in DEFS to ConocoPhillips for direct and indirect monetary and non-monetary consideration of approximately $1.1 billion. Upon closing of this transaction, DEFS expects to transfer its Canadian assets to Duke Energy's Natural Gas Transmission segment and receive certain U.S. Midstream assets or cash from ConocoPhillips. Upon completion of this transaction, DEFS will be owned 50% by Duke Energy and 50% by ConocoPhillips. As a result, Duke Energy expects to account for its investment in DEFS using the equity method subsequent to closing of the transaction. This transaction, which is subject to customary U.S. and Canadian regulatory approvals, is expected to close in the latter half of 2005. Additionally, in February 2005, DEFS sold its wholly-owned subsidiary, TEPPCO, the general partner of TEPPCO Partners L.P., for approximately $1.1 billion and Duke Energy sold its limited partner interest in TEPPCO Partners, L.P. for approximately $100 million, in each case to EPCO, an unrelated third party.

Field Services gathers raw natural gas through gathering systems located in eight major natural gas producing regions: Permian Basin, Mid-Continent, ArklaTex, Gulf Coast, South, Central, Rocky Mountains and Western Canada. Field Services owns and operates approximately 59,000 miles of gathering and transmission pipe, with approximately 34,000 active receipt points.

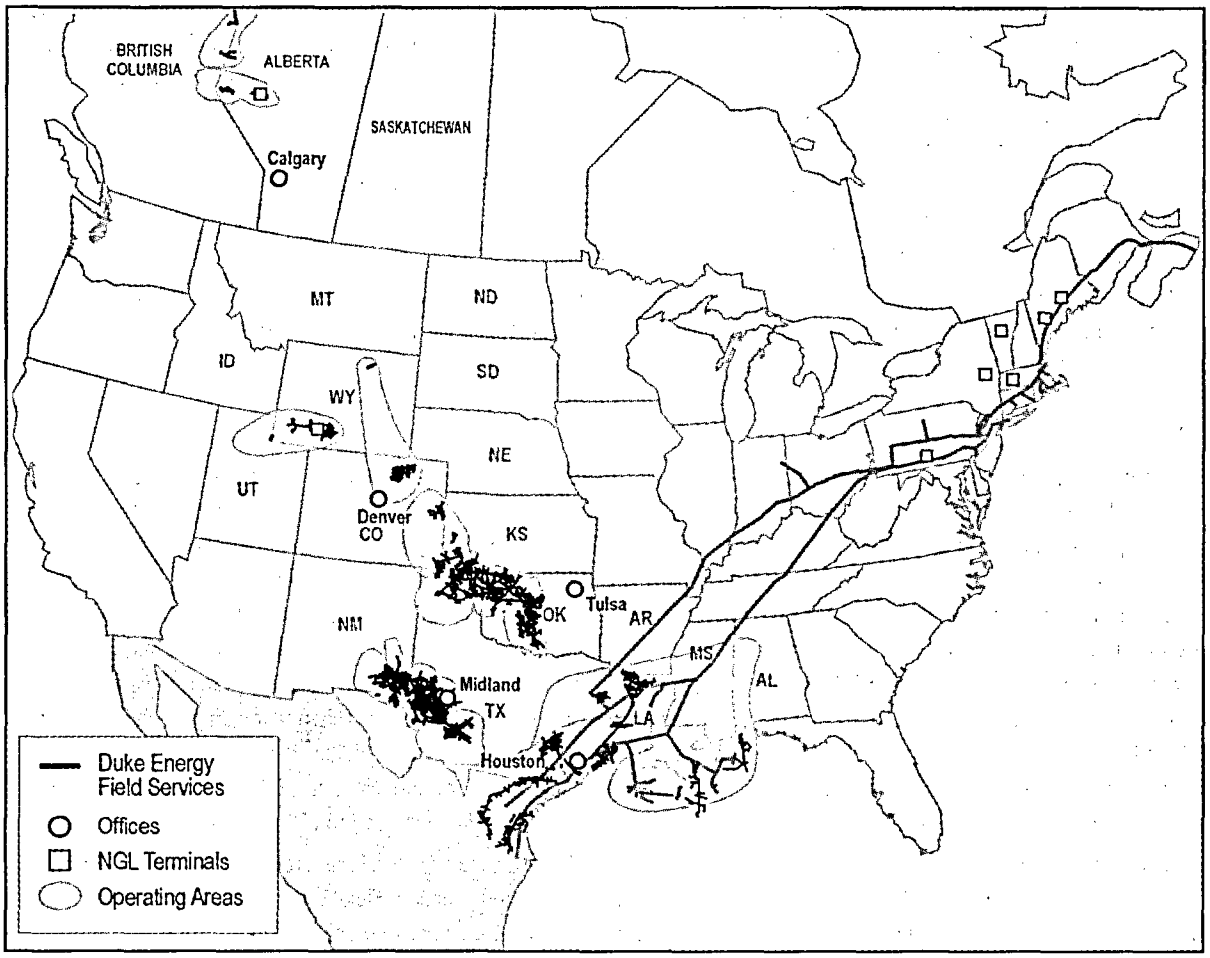
Field Services' natural gas processing operations separate raw natural gas that has been gathered on its own systems and third-party systems into condensate, NGLs and residue gas. Field Services processes the raw natural gas at 57 natural gas processing facilities that it owns and operates and at nine third-party operated facilities in which it has an equity interest.

The NGLs separated from the raw natural gas are either sold and transported as NGL raw mix, or further separated through a fractionation process into their individual components (ethane, propane, butanes and natural gasoline) and then sold as components. Field Services fractionates NGL raw mix at ten processing facilities that it owns and operates and at four third-party-operated facilities in which it has an equity interest. In addition, Field Services operates a propane wholesale marketing business. Field Services sells NGLs to a variety of customers ranging from large, multinational petrochemical and refining companies to small regional retail propane distributors. Substantially all of its NGL sales are at market-based prices.

The residue gas separated from the raw natural gas is sold at market-based prices to marketers and end-users, including large industrial customers and natural gas and electric utilities serving individual consumers. Field Services markets residue gas directly or through its wholly owned gas marketing company and its affiliates. Field Services also stores residue gas at its 6 billion-cubic-foot (Bcf) natural gas storage facility.

Field Services uses NGL trading and storage at the Mont Belvieu, Texas and Conway, Kansas NGL market centers to manage its price risk and to provide additional services to its customers. Asset-based gas trading and marketing activities are supported by ownership of the Spindletop storage facility and various intrastate pipelines which provide access to market centers/hubs such as Katy, Texas, and the Houston Ship Channel. Field Services undertakes these NGL and gas trading activities through the use of fixed forward sales, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. Field Services believes there are additional opportunities to grow its services with its customer base.

The following map includes Field Services' natural gas gathering systems, intrastate pipelines, regional offices and supply areas. The map also shows Natural Gas Transmission's interstate pipeline systems.




Field Services' operating results are significantly impacted by changes in average NGL prices, which increased approximately 28% in 2004 compared to 2003. Field Services closely monitors the risks associated with these price changes, using NGL and crude forward contracts to mitigate the effect of such fluctuations on operating results. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk" for a discussion of Field Services' exposure to changes in commodity prices.)

**Competition**

In gathering and processing natural gas and in marketing and transporting natural gas and NGLs, Field Services competes with major integrated oil companies, major interstate and intrastate pipelines, national and local natural gas gatherers, and brokers, marketers and distributors of natural gas supplies. Competition for natural gas supplies is based primarily on the reputation, efficiency and reliability of operations, the availability of gathering and transportation to high-demand markets, the pricing arrangement offered by the gatherer/processor and the ability of the gatherer/processor to obtain a satisfactory price for the producer's residue gas and extracted NGLs. Competition for sales to customers is based primarily upon reliability, services offered, and price of delivered natural gas and NGLs.

### Regulation

The intrastate natural gas and NGL pipelines owned by Field Services are subject to state regulation. To the extent that the natural gas intrastate pipelines provide services under Section 311 of the Natural Gas Policy Act of 1978, they are also subject to FERC regulation. The interstate natural gas pipeline owned and operated by Field Services is subject to FERC regulation, but its natural gas gathering and processing activities are not subject to FERC regulation.

Field Services is subject to the jurisdiction of the EPA and state environmental agencies. (For more information, see "Environmental Matters" in this section.) Field Services' natural gas transmission pipelines and some gathering pipelines are subject to the regulations of the DOT, and in some cases, state agencies, concerning pipeline safety. DOT regulations have incorporated certain provisions of the Natural Gas Pipeline Safety Act of 1968 (and subsequent acts). The DOT has developed new regulations, effective February 14, 2004, that establish mandatory inspections for all natural gas transmission pipelines in high-consequence areas within ten years, with reassessments at prescribed intervals thereafter. The new regulations require pipeline operators to implement integrity management programs, including more frequent inspections, and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to life and property, Management believes that compliance with these new DOT regulations will not have a material adverse effect on the consolidated results of operations, cash flows or financial position of Duke Energy.

Field Services' Canadian assets are regulated by the Alberta Energy and Utilities Board and the NEB.

### DENA

DENA operates and manages power plants and markets electric power and natural gas related to these plants and other contractual positions. DENA conducts business throughout the U.S. and Canada through Duke Energy North America, LLC and its 100% owned affiliates Duke Energy Marketing America, LLC and Duke Energy Marketing Canada Corp. DENA also participates in DETM. DETM is 40% owned by Exxon Mobil Corporation and 60% owned by Duke Energy. The following summarizes certain key events from 2004.

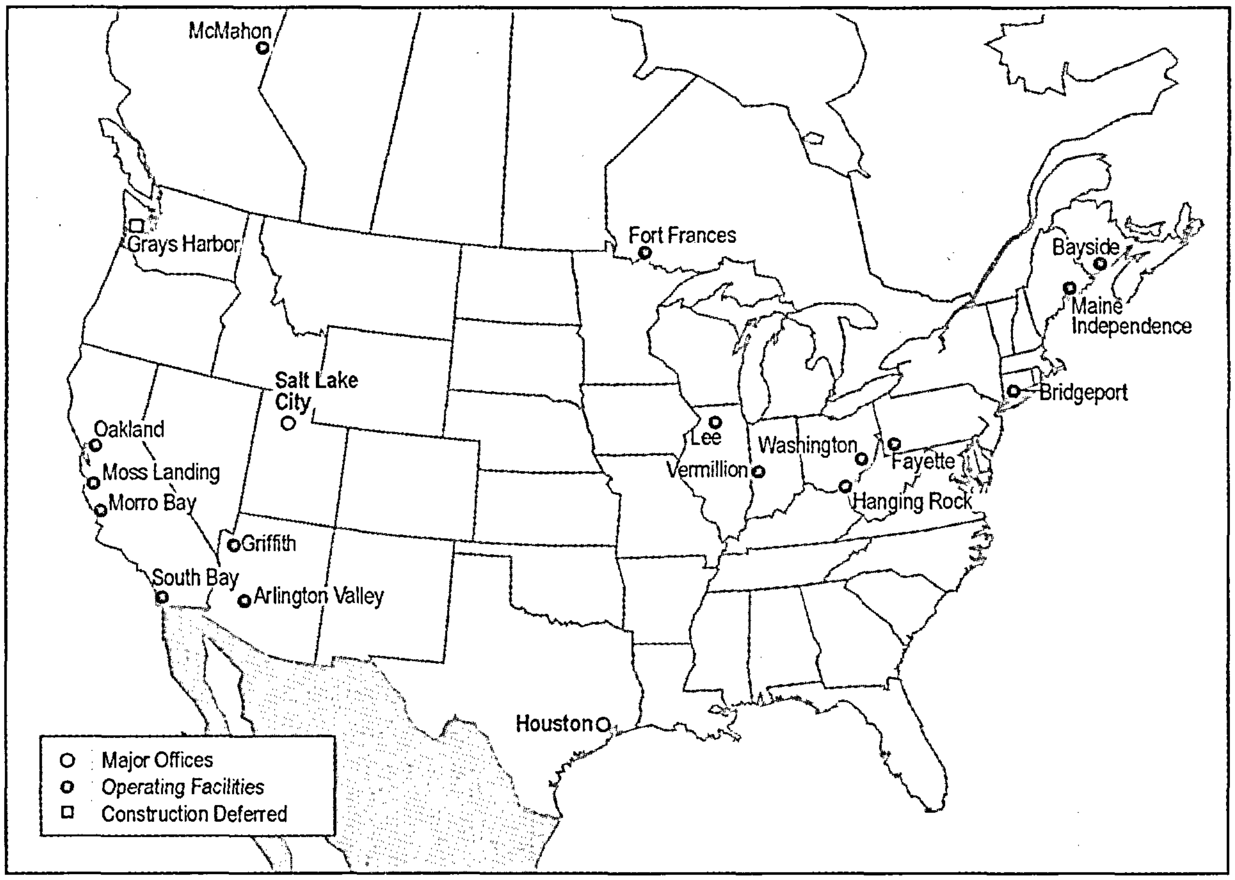
- Sold eight natural gas-fired merchant power plants: Hot Spring (Arkansas); Murray and Sandersville (Georgia); Marshall (Kentucky); Hinds, Southaven, Enterprise and New Albany (Mississippi) in the southeastern United States; and certain other power and gas contracts (collectively, the Southeast Plants)
- Sold partially completed power plants in Nevada (Moapa) and New Mexico (Luna)
- Signed an agreement for the sale of the partially completed Grays Harbor power plant in Washington state
- Settled its Enron Corporation (Enron) bankruptcy proceedings and the majority of its California and Western U.S. energy markets issues, and
- Executed re-organization efforts, resulting in significant staff and annual cost reductions.

### Generation Assets

DENA currently owns or operates approximately 9,890 net MW of operating generation. In August 2004, DENA completed the sale of the Southeast Plants. DENA also completed the sales of its partially completed power plants in Moapa, Nevada in October 2004 and Luna, New Mexico in November 2004. DENA also entered into an agreement in December 2004 to divest of its interests in the partially completed Grays Harbor (Washington) power plant and associated contracts. (See Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions" for further discussion.)

On September 21, 2004 DENA signed a purchase and sale agreement to sell DENA's 75% interests in Bayside Power L.P. (Bayside). (See Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale," for further discussion.)

The following map shows DENA's power generation facilities.




### Marketing Portfolio

Much of DENA's portfolio of purchase and sales agreements incorporate market-sensitive pricing terms. To minimize the impact of changing market conditions to DENA, physical purchases and sales are generally hedged with financial derivatives. Additionally, DENA continues to sell fixed capacity contracts in addition to volume based sales and purchases. (For information concerning DENA's risk-management activities, see "Management's Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk" and Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments.")

DENA is active in the Western (California and Southwest), Northeast and Midwest power markets including the associated gas supply, transport and storage in those markets. DENA has a strong focus on increasing its percentage of contracted energy ($/MWh) and capacity ($/kW/month) versus energy/capacity sold into the spot/non-contracted markets. Additionally, DENA continues to sell fixed capacity contracts in addition to volume based sales and purchases.

### Competition

The price of commodities and services, along with the quality and reliability of services provided, drive competition in the energy marketing business. DENA's competitors include the following: utilities, financial institutions and hedge funds engaged in commodity trading, major interstate pipelines and their marketing affiliates, marketers and distributors, major integrated oil companies, other merchant electric generation companies in North America, brokers, and other domestic and international electric power and natural gas marketers.

### Regulation

DENA's energy marketing activities are subject to the jurisdiction of the FERC in some circumstances. Current FERC policies permit DENA's trading and marketing entities to market natural gas, electricity and other energy-related commodities at market-based rates. Ongoing regulatory initiatives at both state and federal levels addressing market design,such as the development of capacity markets and real-time electricity markets, impact financial results from DENA's marketing and generation activities.

Litigation at the state level is ongoing related to DENA's activities in California during the electricity supply situation in 2000 and 2001. (See Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies—Litigation," for further discussion.)

The operation and maintenance of DENA's power plants in California are now subject to regulation pursuant to guidelines recently promulgated by state authorities. The new guidelines are intended to increase the reliability of the generation supply in California by setting operating and maintenance standards and regulating when plants may be taken out of service for routine maintenance. Duke Energy does not believe that the new guidelines will have a material impact on the operation of its power plants in California.

DENA is subject to the jurisdiction of the EPA and state environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

### INTERNATIONAL ENERGY

International Energy operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U.S. and Canada. It conducts operations primarily through DEI and its activities target power generation in Latin America. Additionally, International Energy owns an equity investment in National Methanol Company, located in Saudi Arabia, which is a leading regional producer of methanol and MTBE.

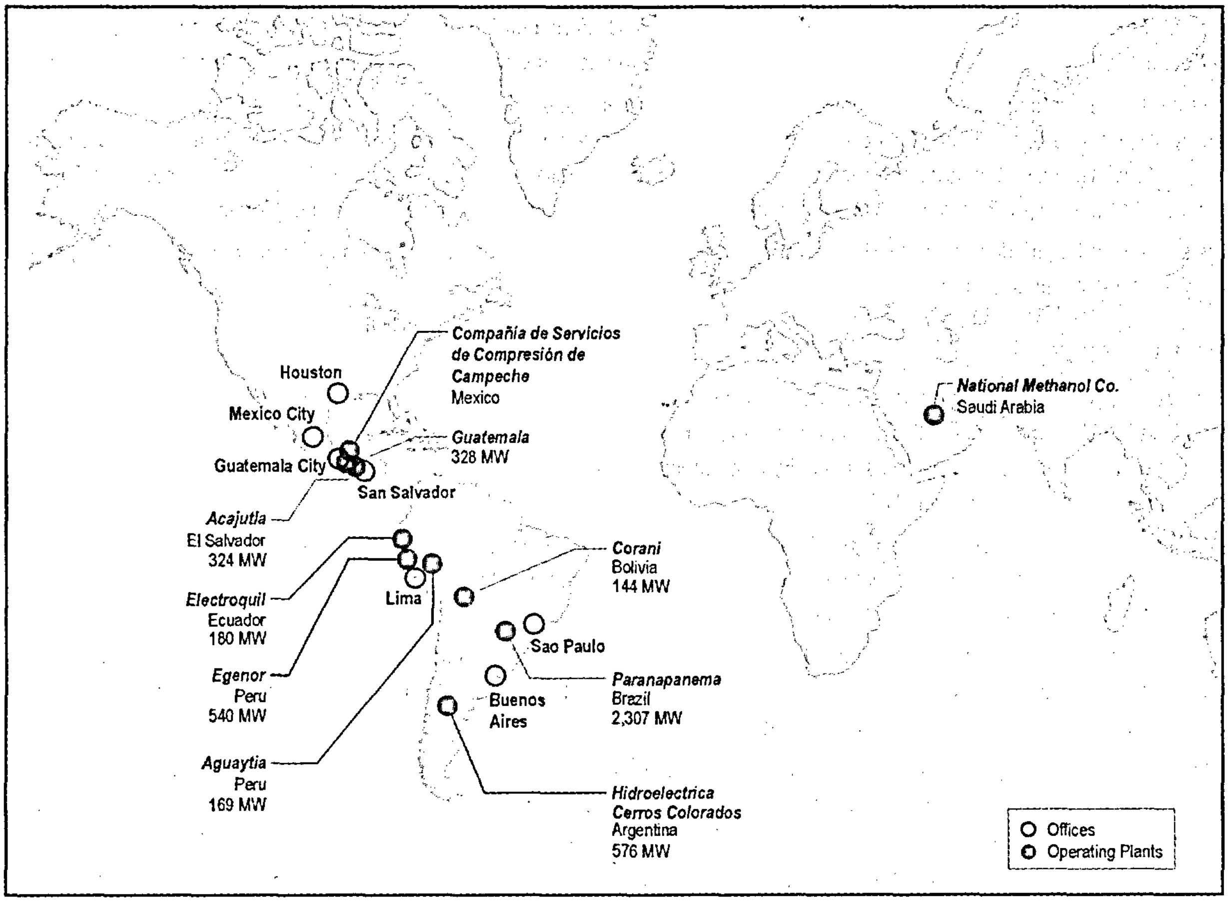
International Energy's customers include retail distributors, electric utilities, independent power producers, marketers and large industrial companies. International Energy is committed to building integrated regional businesses that provide customers with a full range of innovative and competitively priced energy services.

International Energy's current strategy is focused on maximizing the returns and cash flow from its current portfolio of energy businesses by creating organic growth through its sales and marketing efforts in all regions in which it currently does business, optimizing the output and efficiency of its various facilities and controlling and reducing costs.

International Energy owns, operates or has substantial interests in approximately 4,139 net MW of generation facilities. The following map shows the locations of International Energy's facilities, including projects under construction and non-generation facilities in Mexico and Saudi Arabia. The capacities shown in the map are gross MW values (for net MW values see "Properties—International Energy").

During 2004, Duke Energy completed the sale of the Asia-Pacific power generation and natural gas transmission business (the Asia-Pacific Business) to Alinta Ltd. All gains related to this transaction and the results of operations for these assets are included in Discontinued Operations, net of tax, in the Consolidated Statements of Operations. (See Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale," for further discussion.)

Also in 2004, International Energy completed the sale of its 30% equity interest in Compañia de Nitrógeno de Cantarell, S.A. de C.V. (Cantarell) a nitrogen production and delivery facility in the Bay of Campeche, Gulf of Mexico. (See Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions," for further discussion.)




### Competition and Regulation

International Energy's sales and marketing of electric power and natural gas competes directly with other generators and marketers serving its market areas. Competitors are country and region-specific but include government owned electric generating companies, LDC's with self-generation capability and other privately owned electric generating companies. The principal elements of competition are price and availability, terms of service, flexibility and reliability of service.

A high percentage of International Energy's portfolio consists of base-load hydro electric generation facilities which compete with other forms of electric generation available to International Energy's customers and end-users, including natural gas and fuel oils. Economic activity, conservation, legislation, governmental regulations, weather and other factors affect the supply and demand for electricity in the regions served by International Energy.

International Energy's operations are subject to both country-specific and international laws and regulations. (See "Environmental Matters" in this section.)

### CRESCENT

Crescent develops and manages high-quality commercial, residential and multi-family real estate projects, and manages land holdings, primarily in the Southeastern and Southwestern U.S. As of December 31, 2004, Crescent owned 0.5 million square feet of commercial, industrial and retail space, with an additional 1.2 million square feet under construction. This portfolio included 0.9 million square feet of office space, 0.5 million square feet of warehouse space and 0.3 million square feet of retail space. Crescent's residential developments include high-end country club and golf course communities, with individual lots sold to custom builders and tract developments sold to national builders. Crescent had three multi-family communities at December 31, 2004, including one operating property and two properties under development. As of December 31, 2004, Crescent also managed approximately 132,000 acres of land.

**Competition and Regulation**

Crescent competes with multiple regional and national real estate developers across its various business lines in the southeastern and southwestern U.S. Crescent's residential division sells developed lots to regional and national home builders and retail buyers, competing with other developers and home builders who have inventories of developed lots. Crescent's commercial division leases office, industrial and retail space, competing with other public and private developers and owners of commercial property, including national real estate investment trusts (REITs). Similarly, Crescent's multi-family division leases apartment units primarily to individuals, competing with other private developers and multi-family REITs.

Crescent is subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

**OTHER**

During 2004, Other primarily included certain unallocated corporate costs, DukeNet, DEM, Duke Energy's 50% interest in D/FD, and Bison. DCP had been previously included in Other, however at December 31, 2004 Duke Energy had exited the merchant finance business, and all of the results of operations for DCP for the years ended December 31, 2004, 2003 and 2002 have been classified as discontinued operations.

DukeNet develops, owns and operates a fiber optic communications network, primarily in the Carolinas serving wireless, local and long-distance communications companies, Internet service providers and other businesses and organizations.

DEM engages in commodity buying and selling, and risk management and financial services in non-regulated energy commodity markets other than physical natural gas and power (such as petroleum products). DEM's activities can fluctuate in response to seasonal demand for other energy-related commodities. During 2003, Duke Energy determined that it would exit the refined products business at DEM in an orderly manner, and continues to unwind its portfolio of contracts. As of December 31, 2004, DEM had exited the majority of its business.

D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation. During 2003, Duke Energy and Fluor Corporation announced that they would dissolve the D/FD partnership. The D/FD partners adopted a plan for an orderly wind-down of the business which is expected to be completed by December 2005. Previously, D/FD provided comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide.

Bison's principle activities, as a captive insurance entity, include the insurance and reinsurance of various business risks and losses, such as workers compensation, property, business interruption, and general liability of subsidiaries and affiliates of Duke Energy. Bison also participates in reinsurance activities with certain third parties, on a limited basis.

**Competition and Regulation**

The entities within Other are subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

**ENVIRONMENTAL MATTERS**

Duke Energy is subject to international, federal, state and local laws and regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental matters. Environmental laws and regulations affecting Duke Energy include, but are not limited to:

- The Clean Air Act and the 1990 amendments to the Act, as well as state laws and regulations impacting air emissions, including State Implementation Plans related to existing and new national ambient air quality standards for ozone and particulate matter. Owners and/or operators of air emission sources are responsible for obtaining permits and for annual compliance and reporting.
- The Federal Water Pollution Control Act which requires permits for facilities that discharge wastewaters into the environment.
- The Comprehensive Environmental Response, Compensation and Liability Act, which can require any individual or entity that currently owns or in the past may have owned or operated a disposal site, as well as transporters or generators of hazardous substances sent to a disposal site, to share in remediation costs.
- The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, which requires certain solid wastes, including hazardous wastes, to be managed pursuant to a comprehensive regulatory regime.

- The National Environmental Policy Act, which requires federal agencies to consider potential environmental impacts in their decisions, including siting approvals.

(For more information on environmental matters involving Duke Energy, including possible liability and capital costs, see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies—Environmental.")

Except to the extent discussed in Note 4 to the Consolidated Financial Statements, "Regulatory Matters," and Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies," compliance with international, federal, state and local provisions regulating the discharge of materials into the environment, or otherwise protecting the environment, is not expected to have a material adverse effect on the competitive position, consolidated results of operations, cash flows or financial position of Duke Energy.

**GEOGRAPHIC REGIONS**

For a discussion of Duke Energy's foreign operations and the risks associated with them, see "Management's Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk—Foreign Currency Risk," and Notes 3 and 8 to the Consolidated Financial Statements, "Business Segments" and "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments."

**EMPLOYEES**

On December 31, 2004, Duke Energy had approximately 21,500 employees. A total of 3,238 operating and maintenance employees were represented by unions. This amount consists of the following:

- 1,339 employees represented by the International Brotherhood of Electrical Workers
- 1,108 employees represented by the Communications, Energy and Paperworkers of Canada
- 211 employees represented by the United Steelworkers of America
- 208 employees represented by the Canadian Pipeline Employees Association
- 79 employees represented by Sindicato de Trabajadores del Sector Electrico
- 75 employees represented by the International Union of Operating Engineers
- 70 employees represented by Sindicato dos Trabalhadores na Industria da Energia Hidroeletrica de Ipaussu
- 38 employees represented by Sindicato Unico de Centrales de Generacion Electrica—Canon del Pato
- 29 employees represented by Asociacion del Personal Jerarquico del Agua y la Energia
- 24 employees represented by Sindicato dos Trabalhadores na Industria de Energia Eletrica de Campinas
- 20 employees represented by Sindicato Corani
- 15 employees represented by Sindicato Unico de Generacion Electrica—Carhuaquero
- 13 employees represented by Federacion Argentina de Trabajadores de Luz y Fuerza
- 7 employees represented by Sindicato dos Trabalhadores nas Industrias de Energia Eletrica de Sao Paulo
- 2 employees represented by the United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industries of the U.S. and Canada

**EXECUTIVE OFFICERS OF DUKE ENERGY**

PAUL M. ANDERSON, 59, Chairman of the Board and Chief Executive Officer. Mr. Anderson was named to his current position in November 2003. Mr. Anderson most recently served as Managing Director and Chief Executive Officer of BHP Billiton Ltd and BHP Billiton PLC, from which he retired in July 2002. Prior to joining BHP, Mr. Anderson had a career that spanned more than 20 years at Duke Energy and its predecessor companies, including serving as Chief Executive Officer of PanEnergy Corp (PanEnergy).

KEITH G. BUTLER, 44, Vice President and Controller. Mr. Butler was named Senior Vice President and Chief Financial Officer of Duke Energy Global and its affiliated companies in February 1998, Senior Vice President and Chief Financial Officer of DENA in July 1998, and Chief Operating Officer of DukeSolutions, Inc. in September 1999 before he assumed his current position in August 2001.

MYRON L. CALDWELL, 47, Vice President and Treasurer. Mr. Caldwell was named to his current position in December 2003. He previously served as Vice President of Corporate Finance since October 2000, and Managing Director of Corporate Finance since September 1999. Mr. Caldwell held various other positions since joining Duke Energy in 1981, including Controller of Duke Power and Senior Vice President and Chief Financial Officer of Duke Engineering & Services, Inc.

FRED J. FOWLER, 59, President and Chief Operating Officer. Mr. Fowler assumed his current position in November 2002. Mr. Fowler served as Group Vice President of PanEnergy from 1996 until the PanEnergy merger in 1997, when he was named Group President, Energy Transmission.

DAVID L. HAUSER, 53, Group Vice President and Chief Financial Officer. Mr. Hauser assumed his current position in March 2004, but served as Acting Chief Financial Officer since December 2003. He previously served as Senior Vice President and Treasurer. Mr. Hauser held various positions, including Controller of Duke Power before being named Senior Vice President, Global Asset Development in 1997.

JIM W. MOGG, 56, Group Vice President and Chief Development Officer. Mr. Mogg assumed his current position in January 2004. He previously served as President and Chief Executive Officer of DEFS since December 1994 and Chairman, President and Chief Executive Officer of DEFS since 1999.

A.R. MULLINAX, 50, Group Vice President and Chief Information Officer. Mr. Mullinax assumed his current position in October 2004. He previously served as Vice President of Business Services. Mr. Mullinax has held various positions including Senior Vice President of Shared Services, Global Sourcing, and Duke Ventures as well as President and Chief Executive Officer of DukeNet.

THOMAS C. O'CONNOR, 49, Group Vice President (Executive Officer effective March 1, 2005). Mr. O'Connor assumed his current position in March 2005. He previously served as President and Chief Executive Officer of Duke Energy Gas Transmission since December 2002. He has also served in leadership positions with Duke Energy's pipeline operations since 1994. Mr. O'Connor joined Duke Energy in 1987 as Supervisor of Environmental Compliance for Algonquin Gas Transmission LLC (Algonquin) in New England.

RICHARD J. OSBORNE, 54, Group Vice President, Public and Regulatory Policy. Mr. Osborne assumed his current position in January 2004. He previously served as Executive Vice President and Chief Risk Officer. He also served as Executive Vice President and Chief Financial Officer since 1997 and Senior Vice President and Chief Financial Officer since 1994.

RUTH G. SHAW, 57, President and Chief Executive Officer, Duke Power. Dr. Shaw assumed her current position in February 2003. Dr. Shaw served as Senior Vice President, Corporate Resources, from 1994 until the PanEnergy merger in 1997, when she was named Executive Vice President and Chief Administrative Officer.

B. KEITH TRENT, 45, Group Vice President, General Counsel and Secretary, in an acting capacity (Executive Officer effective March 1, 2005). Mr. Trent assumed his current position in March 2005. He previously served as General Counsel, Litigation since May 2002 when he joined Duke Energy. He previously served as a partner in the law firm Snell, Brannian & Trent since October 1991.

MARTHA B. WYRSCH, 47, President and Chief Executive Officer of Duke Energy Gas Transmission (Executive Officer until March 1, 2005). Ms. Wyrsch assumed her current position in March 2005. She previously served as Group Vice President, General Counsel and Secretary since January 2004. She also served as Senior Vice President of Legal Affairs. Ms. Wyrsch joined Duke Energy in September 1999 as Senior Vice President, General Counsel and Secretary for DEFS.

Executive officers are elected annually by the Board of Directors. They serve until the first meeting of the Board of Directors following the annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection.

## Item 2. Properties.

### FRANCHISED ELECTRIC

As of December 31, 2004, Franchised Electric operated three nuclear generating stations with a combined net capacity of 5,020 MW (including a 12.5% ownership in the Catawba Nuclear Station), eight coal-fired stations with a combined capacity of 7,754 MW, 31 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 2,810 MW and seven combustion turbine stations with a combined capacity of 2,447 MW. All of the stations are located in North Carolina or South Carolina.

| Name | Gross MW | Net MW | Fuel | Location | Ownership Interest (percentage) |
|---|---|---|---|---|---|
| Oconee | 2,538 | 2,538 | Nuclear | SC | 100% |
| Catawba | 2,258 | 282 | Nuclear | SC | 12.5 |
| Belews Creek | 2,270 | 2,270 | Coal | NC | 100 |
| McGuire | 2,200 | 2,200 | Nuclear | NC | 100 |
| Marshall | 2,110 | 2,110 | Coal | NC | 100 |
| Lincoln CT | 1,267 | 1,267 | Natural gas/Fuel Oil | NC | 100 |
| Allen | 1,145 | 1,145 | Coal | NC | 100 |
| Bad Creek | 1,065 | 1,065 | Hydro | SC | 100 |
| Cliffside | 760 | 760 | Coal | NC | 100 |
| Jocassee | 610 | 610 | Hydro | SC | 100 |
| Riverbend | 454 | 454 | Coal | NC | 100 |
| Lee | 370 | 370 | Coal | SC | 100 |
| Buck | 369 | 369 | Coal | NC | 100 |
| Cowans Ford | 325 | 325 | Hydro | NC | 100 |
| Mill Creek CT | 596 | 596 | Natural gas/Fuel Oil | SC | 100 |
| Dan River | 276 | 276 | Coal | NC | 100 |
| Buzzard Roost CT | 196 | 196 | Natural gas/Fuel Oil | SC | 100 |
| Keowee | 160 | 160 | Hydro | SC | 100 |
| Riverbend CT | 120 | 120 | Natural gas/Fuel Oil | NC | 100 |
| Buck CT | 93 | 93 | Natural gas/Fuel Oil | NC | 100 |
| Lee CT | 90 | 90 | Natural gas/Fuel Oil | SC | 100 |
| Dan River CT | 85 | 85 | Natural gas/Fuel Oil | NC | 100 |
| Other small hydro (27 plants) | 650 | 650 | Hydro | NC/SC | 100 |
| Total | 20,007 | 18,031 | | | |

In addition, as of December 31, 2004, Franchised Electric owned approximately 13,000 conductor miles of electric transmission lines, including 600 miles of 525 kilovolts, 2,600 miles of 230 kilovolts, 6,600 miles of 100 to 161 kilovolts, and 3,200 miles of 13 to 66 kilovolts. Franchised Electric also owned approximately 94,000 conductor miles of electric distribution lines, including 49,800 miles of rural overhead lines, 16,100 miles of urban overhead lines, 15,400 miles of rural underground lines and 12,700 miles of urban underground lines. As of December 31, 2004, the electric transmission and distribution systems had approximately 1,600 substations.

Substantially all of Franchised Electric's electric plant in service is mortgaged under the indenture relating to Duke Energy's various series of First and Refunding Mortgage Bonds.

(For a map showing Franchised Electric's properties, see "Business—Franchised Electric" earlier in this section.)

### NATURAL GAS TRANSMISSION

Texas Eastern's gas transmission system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York. It consists of two parallel systems, one with three large-diameter parallel pipelines and the other with one to three large-diameter pipelines. Texas Eastern's onshore system consists of approximately 8,600 miles of pipeline and 73 compressor stations.

Texas Eastern also owns and operates two offshore Louisiana pipeline systems, which extend approximately 100 miles into the Gulf of Mexico and include approximately 500 miles of Texas Eastern's pipeline system.

Texas Eastern has two joint-venture storage facilities in Pennsylvania and one wholly owned and operated storage field in Maryland. Texas Eastern's total working capacity in these three fields is 75 Bcf.

Algonquin transmission system connects with Texas Eastern's facilities in New Jersey, and extends approximately 250 miles through New Jersey, New York, Connecticut, Rhode Island and Massachusetts. The system consists of approximately 1,100 miles of pipeline with six compressor stations.

ETNG's transmission system crosses Texas Eastern's system at two points in Tennessee and consists of two mainline systems totaling approximately 1,400 miles of pipeline in Tennessee, Georgia, North Carolina and Virginia, with 18 compressor stations.

ETNG has an LNG storage facility in Tennessee with a total working capacity of 1.2 Bcf.

Maritimes & Northeast Pipeline, LLC and Maritimes & Northeast Pipeline, LP (collectively, Maritimes & Northeast) transmission system (approximately 78% owned by Duke Energy) extends approximately 900 miles from producing fields in Nova Scotia through New Brunswick, Maine, New Hampshire and Massachusetts, connecting to Algonquin in Beverly, Massachusetts. It has two compressor stations on the system.

The British Columbia Pipeline System consists of two divisions. The field services division operates more than 1,840 miles of gathering pipelines in British Columbia, Alberta, the Yukon Territory and the Northwest Territories, as well as 22 field compressor stations; four gas processing plants located in British Columbia near Fort Nelson, Taylor, Chetwynd and in the Sikanni area northwest of Fort St. John, and three elemental sulphur recovery plants located at Fort Nelson, Taylor and Chetwynd. Total contractible capacity is approximately 1.8 Bcf of residue gas per day. The pipeline division has approximately 1,740 miles of transmission pipelines in British Columbia and Alberta, as well as 18 mainline compressor stations.

Union Gas owns and operates natural gas transmission, distribution and storage facilities in Ontario. Union Gas' distribution system consists of approximately 22,000 miles of distribution pipelines. Union Gas' underground natural gas storage facilities have a working capacity of approximately 150 Bcf in 20 underground facilities located in depleted gas fields. Its transmission system consists of approximately 3,000 miles of pipeline and six mainline compressor stations.

MHP owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 31 Bcf. The Moss Bluff facility consists of three storage caverns located in southeast Texas and has access to five pipeline systems. The Egan facility consists of three storage caverns located in south central Louisiana and has access to eight pipeline systems.

Natural Gas Transmission also has an investment in Gulfstream National Gas System, LLC (Gulfstream), a 691-mile interstate natural gas pipeline system owned and operated jointly by Duke Energy and The Williams Company, Inc. The Gulfstream gas pipeline has a capacity of 1.1 Bcf of natural gas per day and transports gas from the Mobile Bay area, across the Gulf of Mexico, to growing gas markets in south and central Florida. Gulfstream began initial service in May 2002.

(For a map showing natural gas transmission and storage properties, see "Business—Natural Gas Transmission" earlier in this section.)

### FIELD SERVICES

(For information and a map showing Field Services' properties, see "Business—Field Services" earlier in this section.)

### DENA

The following table provides information about DENA's generation portfolio in continuing operations as of December 31, 2004.

| Name | Gross MW | Net MW | Plant Type | Primary Fuel | Location | Approximate Ownership Interest (percentage) |
|---|---|---|---|---|---|---|
| Moss Landing | 2,538 | 2,538 | Combined Cycle | Natural Gas | CA | 100% |
| Hanging Rock | 1,240 | 1,240 | Combined Cycle | Natural Gas | OH | 100 |
| Morro Bay | 1,002 | 1,002 | Combined Cycle | Natural Gas | CA | 100 |
| South Bay | 700 | 700 | Combined Cycle | Natural Gas | CA | 100 |
| Lee | 640 | 640 | Simple Cycle | Natural Gas | IL | 100 |
| Vermillion | 640 | 480 | Simple Cycle | Natural Gas | IN | 75 |
| Fayette | 620 | 620 | Combined Cycle | Natural Gas | PA | 100 |
| Washington | 620 | 620 | Combined Cycle | Natural Gas | OH | 100 |
| Griffith Energy | 600 | 300 | Combined Cycle | Natural Gas | AZ | 50 |
| Arlington Valley | 570 | 570 | Combined Cycle | Natural Gas | AZ | 100 |
| Maine Independence | 520 | 520 | Combined Cycle | Natural Gas | ME | 100 |
| Bridgeport | 490 | 326 | Combined Cycle | Natural Gas | CT | 67 |
| Oakland | 165 | 165 | Simple Cycle | Oil | CA | 100 |
| McMahon | 117 | 59 | Cogen | Natural Gas | BC | 50 |
| Ft. Frances | 110 | 110 | Cogen | Natural Gas | ON | 100 |
| Total | 10,572 | 9,890 | | | | |

(For a map showing DENA's properties, see "Business—DENA" earlier in this section.)

### INTERNATIONAL ENERGY

The following table provides information about International Energy's generation portfolio in continuing operations as of December 31, 2004.

| Name | Gross MW | Net MW | Fuel | Location | Approximate Ownership Interest (percentage) |
|---|---|---|---|---|---|
| Paranapanema | 2,307 | 2,185 | Hydro | Brazil | 95% |
| Hidroelectrica Cerros Colorados | 576 | 523 | Hydro/Natural gas | Argentina | 91 |
| Egenor | 540 | 538 | Hydro/Diesel/Oil | Peru | 100 |
| DEI Guatemala | 328 | 328 | Orimulsion/Oil/Diesel | Guatemala | 100 |
| Acajutla | 324 | 293 | Oil/Diesel | El Salvador | 90 |
| Electroquil | 180 | 136 | Diesel | Ecuador | 75 |
| Aguaytia | 169 | 64 | Natural Gas | Peru | 38 |
| Empressa Electrica Corani | 144 | 72 | Hydro | Bolivia | 50 |
| Total | 4,568 | 4,139 | | | |

In addition to those generating facilities, International Energy owns a 25% equity interest in National Methanol Company (NMC), located in Saudi Arabia, which is a leading producer of methanol and MTBE. In 2004, the NMC produced approximately 900 thousand metric tons of methanol and one million metric tons of MTBE. International Energy also owns a 50% equity interest in Compañía de Servicios de Compresión de Campeche, S.A. de C.V. (Campeche), located in the Cantarell oil field in the Bay of Campeche, Mexico, which compresses and dehydrates natural gas and extracts NGLs. Campeche has an installed processing capacity of 270 Mmcf/d. (For additional information and a map showing International Energy's properties, see "Business—International Energy" earlier in this section.)

### CRESCENT

(For information regarding Crescent's properties, see "Business—Crescent" earlier in this section.)

### OTHER

(For information regarding the properties of the business unit now known as Other, see "Business—Other" earlier in this section.)

## Item 3. Legal Proceedings.

In July 2003, a fire occurred at the Moss Landing Power Plant in California, operated by Duke Energy Moss Landing LLC (DEML), a subsidiary of DENA, when fuel oil was ignited by a contractor performing tank clean out and dismantling activities. The Monterey County District Attorney initiated civil enforcement action against DEML alleging violations of the California Health and Safety Code and the Business and Professions Code. The alleged violations concerned the handling of hazardous materials at the site and unlawful release of hazardous materials into the environment. DEML denied the allegations but agreed to settle the civil enforcement action by committing to expend a total of $752,287, the majority of which entails reimbursement of costs to the county and expenditures for safety/environmental training efforts by the company, but also includes a $100,000 civil penalty payment. The district attorney also settled a related action against DEML's contractor for alleged violations in the incident. Both settlements were announced on September 22, 2004.

(For information regarding legal proceedings, including regulatory and environmental matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters" and Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies—Litigation" and "Commitments and Contingencies—Environmental.")

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

No matters were submitted to a vote of Duke Energy's security holders during the fourth quarter of 2004.

## Item 5. Market for Registrant's Common Equity and Related Stockholder Matters.

Duke Energy's common stock is listed for trading on the New York Stock Exchange. As of February 28, 2005, there were approximately 143,800 common stockholders of record.

**Common Stock Data by Quarter**

| | 2004 | | | 2003 | | |
|---|---|---|---|---|---|---|
| | | Stock Price Range[a] | | | Stock Price Range[a] | |
| | Dividends Per Share | High | Low | Dividends Per Share | High | Low |
| First Quarter | $0.275 | $22.70 | $19.90 | $0.275 | $21.57 | $12.21 |
| Second Quarter | 0.550 | 22.90 | 18.85 | 0.550 | 20.75 | 13.51 |
| Third Quarter | — | 23.00 | 19.84 | — | 19.70 | 16.75 |
| Fourth Quarter | 0.275 | 26.16 | 22.85 | 0.275 | 20.89 | 17.08 |

(a) Stock prices represent the intra-day high and low stock price.

On December 17, 1998, Duke Energy's Board of Directors adopted a shareholder rights plan. Under the terms of the plan, one preference stock purchase right was distributed for each share of common stock outstanding on February 12, 1999, and for each share issued thereafter, subject to adjustment as specified. The NCUC and the PSCSC approved this distribution. The plan is intended to ensure the fair treatment of all shareholders in the event of a hostile takeover attempt and to encourage a potential acquirer to negotiate with the Board of Directors a fair price for all shareholders before attempting a takeover. The adoption of the plan was not in response to any takeover offer or threat. The Corporate Governance Committee of the Board of Directors evaluates the plan at least once every three years, and most recently evaluated the plan in October 2004.

## Item 6. Selected Financial Data.

| | 2004 | 2003(b) | 2002 | 2001 | 2000 |
|---|---|---|---|---|---|
| | (in millions, except per share amounts) | | | | |
| **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 |

(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 (EITF) 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 SFAS 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. (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for further discussion.)
(c) Earnings were inadequate to cover fixed charges by $1,707 million for the year ended December 31, 2003.

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

### INTRODUCTION

Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements.

**Overview of Business Strategy.** Duke Energy's business strategy is to create value for customers, employees, communities and shareholders through the production, conversion, delivery and sale of energy and energy services. Duke Energy's plan is to emphasize income for its shareholders, with modest growth.

For the past few years, the energy industry including Duke Energy experienced a number of challenges, including the substantial imbalance between supply and demand for electricity, the pace of economic recovery, and regulatory and legal uncertainties. In response to these challenges, Duke Energy's focus for 2004 was to reduce risks and restructure its business. By selling assets such as Duke Energy North America's (DENA's) eight natural gas-fired merchant power plants: Hot Spring (Arkansas); Murray and Sandersville (Georgia); Marshall (Kentucky); Hinds, Southaven, Enterprise and New Albany (Mississippi) in the southeastern United States; (collectively, the Southeast Plants) and International Energy's Asia-Pacific power generation and natural gas transmission business (the Asia-Pacific Business), Duke Energy eliminated some of its lowest return assets. These asset sales provided cash proceeds allowing Duke Energy to pay down debt and strengthen its balance sheet. Progress was also made in 2004 in resolving some critical legal and regulatory issues.

As a result of the efforts in 2004, Duke Energy's objectives for 2005 include establishing industry-leading positions in core businesses and identifying new energy-related growth strategies, focused in the Americas. Increased demand for natural gas supplies in the United States and changing logistics among source of supply are providing opportunities for growth. To capitalize on this market dynamic, Natural Gas Transmission is evaluating longer-term opportunities to provide pipeline capacity and storage facilities for the expected expansion of the liquefied natural gas (LNG) market. Additionally, the strength of the natural gas market provides incentives for producers to increase exploration and production, which in turn, provides business sustainability and growth opportunities for Field Services. Duke Power and International Energy are expected to grow organically for the near term.

In February 2005, Duke Energy Field Services LLC (DEFS) sold Texas Eastern Products Pipeline Company LLC (TEPPCO) for approximately $1.1 billion and Duke Energy sold its limited partner interest in TEPPCO Partners, L.P. for approximately $100 million, in each case to EPCO, an unrelated third party. These transactions closed in the first quarter of 2005.

In February 2005, Duke Energy executed an agreement with ConocoPhillips whereby Duke Energy has agreed to transfer a 19.7% interest in DEFS to ConocoPhillips for direct and indirect monetary and non-monetary consideration of approximately $1.1 billion. Upon completion of this transaction, DEFS will be owned 50% by Duke Energy and 50% by ConocoPhillips. As a result, Duke Energy expects to account for its investment in DEFS using the equity method subsequent to closing of the transaction, which is expected to occur in the latter half of 2005.

Duke Energy believes merchant energy will play a vital role in meeting the United States' energy demand. Another key objective for 2005 is to position DENA to be a successful merchant operator. During 2004, DENA's business model changed to focus on selling fixed capacity contracts in addition to volume based sales and purchases. Duke Energy is pursuing various options to create a sustainable business model for DENA, including consideration of potential business partners. A sustainable business model will include fuel and geographic diversity, sufficient size and scope for a substantial market presence and will enable DENA to better withstand the cyclical nature of the industry. Depending on the option selected, there is a risk that material impairments or losses could be recorded, including the potential disqualification of certain contracts and the recognition of unrealized losses associated with DENA power forward sales contracts designated under the normal purchases and normal sales exemption, which totaled approximately $900 million (pre-tax) as of December 31, 2004. This unrealized loss represents the difference in the normal purchases and normal sales contract prices compared to the forward market prices of power and is partially offset by unrealized gains on natural gas positions of approximately $800 million (pretax) as of December 31, 2004. (For more information see Commodity Price Risk discussion under Quantitative and Qualitative Disclosures About Market Risk).

With cash, cash equivalents and short-term investments on hand at December 31, 2004 of approximately $1.9 billion and a more stable business environment, Duke Energy has financial flexibility to buy back common stock, invest incrementally or pay down additional debt. Duke Energy is evaluating these options and will determine the best economic decisions to meet the needs of shareholders and ensure the long-term financial strength of Duke Energy. In connection with the TEPPCO and DEFS transactions discussed above, Duke Energy has announced plans to periodically repurchase up to an aggregate $2.5 billion of its common stock over the next three years.

Other key objectives for Duke Energy in 2005 are to build stakeholder relationships through effective leadership on key policy issues related to energy, regulation and the environment, and also to focus on safety, inclusion and diversity, employee development, business structure and process simplification.

These objectives, along with delivering on Duke Energy's financial plan, are set with the intent to provide superior total shareholder return.

**Economic Factors for Duke Energy's Business.** Duke Energy's business model provides diversification between stable, less cyclical businesses like Franchised Electric and Natural Gas Transmission, and the traditionally higher-growth and more cyclical energy businesses like DENA, International Energy and Field Services. Additionally, Crescent Resources LLC's (Crescent's) portfolio strategy is diversified between residential, commercial and multi-family development. All of Duke Energy's businesses can be negatively affected by sustained downturns or sluggishness in the economy, including low market price of commodities, all of which are beyond Duke Energy's control, and could impair Duke Energy's ability to meet its goals for 2005 and beyond.

Declines in demand for electricity as a result of economic downturns would reduce overall electricity sales and lessen Duke Energy's cash flows; especially as industrial customers reduce production and, thus, consumption of electricity. A portion of Franchised Electric's business risk is mitigated by its being subject to regulated allowable rates of return and recovery of fuel costs under fuel adjustment clauses. Natural Gas Transmission is also subject to mandated tariff rates and recovery of certain fuel costs. Lower economic output would also cause the Natural Gas Transmission and Field Services businesses to experience a decline in the volume of natural gas shipped through their pipelines, gathered and processed at their plants, or distributed by their local distribution company, resulting in lower revenue and cash flows. Natural Gas Transmission continues to experience positive renewals of its customer contracts as they expire.

If negative market conditions persist over time and estimated cash flows over the lives of Duke Energy's individual assets do not exceed the carrying value of those individual assets, asset impairments may occur in the future under existing accounting rules and diminish results of operations. Furthermore, a change in management's intent about the use of individual assets (held for use versus held for sale) or a change in fair value of assets held for sale could also result in impairments or losses.

Duke Energy's goals for 2005 can also be substantially at risk due to the regulation of its businesses. Duke Energy's businesses in North America are subject to regulations on the federal and state level. The majority of Duke Energy's Canadian natural gas assets is also subject to various degrees of federal or provincial regulation and is subject to the same risks. Regulations, applicable to the electric power industry and gas transmission and storage industry, have a significant impact on the nature of the businesses and the manner in which they operate. Changes to regulations are ongoing and Duke Energy cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on its business.

Additionally, Duke Energy's investments and projects located outside of the United States expose it to risks related to laws of other countries, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. Changes in these factors are difficult to predict and may impact Duke Energy's future results. Duke Energy's recent restructuring, which focuses its non-United States operations on only Latin America and Canada, will help mitigate this exposure.

Duke Energy also relies on access to both short-term money markets and longer-term capital markets as a source of liquidity for capital requirements not met by the cash flow from its operations. If Duke Energy is not able to access capital at competitive rates, its ability to implement its strategy could be adversely affected. Market disruptions or a downgrade of Duke Energy's credit rating may increase its cost of borrowing or adversely affect its ability to access one or more sources of liquidity.

## RESULTS OF OPERATIONS

### Overview of Drivers and Variances for 2004 and 2003

*Year Ended December 31, 2004 as Compared to December 31, 2003.* For 2004, earnings available for common stockholders were \$1,481 million, or \$1.59 per basic share and \$1.54 per diluted share. For 2003, earnings available for common stockholders were a loss of \$1,338 million, or a loss of \$1.48 per basic and diluted share. Significant items that contributed to the improved results in 2004 included:

- Pre-tax charges of \$2.8 billion in 2003 related to asset impairments of: DENA's Southeast Plants which were sold during 2004, DENA's partially completed Western plants, two of which were sold in 2004 and wind-down costs associated with the Duke Energy Trading and Marketing LLC (DETM) joint venture
- A \$295 million pre-tax gain (\$273 million net of tax) recorded in 2004 on the sale of International Energy's Asia-Pacific Business, slightly offset by a loss on its European gas trading and marketing business (European Business)

- Net pre-tax charges and impairments of $292 million ($223 million net of tax) in 2003 for International Energy's Asia-Pacific and European Businesses, which were classified as discontinued operations and subsequently sold in 2004
- Pre-tax charges of $262 million in 2003 for the disqualification of certain hedges and contracts that were being accounted for as normal purchases and normal sales from the Accrual Model to the MTM Model that were related to the impaired assets at DENA
- A pre-tax charge of $254 million in 2003 for goodwill impairment at DENA, related primarily to the trading and marketing business
- Pre-tax gains of $180 million on the sales of two partially completed plants at DENA in 2004
- Charges in 2003 related to changes in accounting principles of $162 million, net of tax and minority interest
- Pre-tax severance and related charges of $153 million in 2003 associated with workforce reductions across all segments, net of minority interest of $2 million
- A $130 million (net of minority interest of $5 million) pre-tax gain in 2004 related to the settlement of the Enron bankruptcy proceedings
- A $64 million pre-tax decrease in 2004 Operating Expenses as a result of the correction of an accounting error in prior periods related to reserves at Bison Insurance Company Limited (Bison) for property losses at several Duke Energy subsidiaries
- The reduction of various income tax reserves in 2004 totaling approximately $52 million (see Note 6 to the Consolidated Financial Statements, "Income Taxes")
- A pre-tax charge of $51 million in 2003 for the write-off of an abandoned corporate risk management information system
- A $48 million tax benefit in 2004 related to the realignment of certain subsidiaries of Duke Energy and the pass-through structure of these for U.S. income tax purposes (see Note 6 to the Consolidated Financial Statements, "Income Taxes")
- A regulatory action by the Public Service Commission of South Carolina (PSCSC) in 2003 which resulted in decreased pre-tax earnings of $46 million at Franchised Electric, $16 million of which was due to an order to write-off regulatory assets related to debt issuance costs through interest expense
- Increased 2004 earnings at Field Services due to favorable effects of commodity prices and improved results from trading and marketing activities, and
- Increased residential developed lot sales, commercial project and land management ("legacy" land sales) at Crescent, due to several large sales that closed in 2004.

Partially offsetting these increases and prior year charges were:

- An approximate $360 million pre-tax charge in the first quarter of 2004 associated with the sale of DENA's Southeast Plants (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions")
- A $178 million pre-tax gain in 2003 from the sale of DENA's 50% interest in Duke/UAE Ref-Fuel LLC (Ref-Fuel)
- A $105 million pre-tax charge in 2004 related to the California and western U.S. energy markets settlement (see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies")
- A $52 million income tax benefit in 2003 related to the write-off of goodwill at International Energy's European Business in 2002, and
- An increase of $45 million related to taxes recorded in 2004 on the repatriation of foreign earnings that is expected to occur in 2005 associated with the American Jobs Creation Act

For additional information on specific business unit related items, see the segment discussions that follow. For a detailed discussion of interest, taxes and the impact of changes in accounting principles, see "Other Impacts on Earnings Available for Common Stockholders" at the end of this section.

**Consolidated Operating Revenues**

*Year Ended December 31, 2004 as Compared to December 31, 2003.* Consolidated operating revenues for 2004 increased $423 million, compared to 2003. This change was driven by:

- A $97 million increase in Non-regulated Electric, Natural Gas, Natural Gas Liquids, and Other revenues due to higher average NGL and natural gas prices at Field Services, partially offset by the continued wind-down of DETM and Duke Energy Merchants, LLC (DEM)
- A $151 million increase in Regulated Electric revenues, due primarily to increased fuel rates charged to retail customers as a result of increased coal costs and increased sales resulting from favorable weather at Franchised Electric. The increase was also attributable to the continued growth in the number of Franchised Electric residential and general service customers, and

- A $175 million increase in Regulated Natural Gas revenues, due primarily to the strengthening Canadian dollar at Natural Gas Transmission.

*Year Ended December 31, 2003 as Compared to December 31, 2002.* Consolidated operating revenues for 2003 increased $6,220 million, compared to 2002. This change was primarily driven by:

- A $5,398 million increase in Non-regulated Electric, Natural Gas, Natural Gas Liquids, and Other revenues, due primarily to increased NGL pricing, and due to the adoption of the final consensus on Emerging Issues Task Force (EITF) 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," on January 1, 2003. As of that date, Duke Energy began to report revenues and expenses for certain derivative and non-derivative gas and other contracts on a gross basis instead of a net basis. Adopting the final consensus on EITF Issue No. 02-03 did not require a change to prior periods, which had already been changed in 2002 to report amounts on a net basis in accordance with earlier provisions of EITF Issue No. 02-03, and
- A $742 million increase in Regulated Natural Gas revenues due primarily to increased transportation, storage and distribution revenues from assets acquired or consolidated as a part of the acquisition of Westcoast Energy Inc. (Westcoast) in March 2002.

**Consolidated Operating Expenses**

*Year Ended December 31, 2004 as Compared to December 31, 2003.* Consolidated operating expenses for 2004 decreased $3,362 million, compared to 2003. The change was primarily driven by:

- A $2,891 million decrease in Impairments and Other Related Charges due primarily to charges of $2,903 in 2003 resulting from strategic actions taken at DENA which led to the recording of impairments related to the Southeast Plants, partially completed plants, disqualified hedges and normal purchases and sales contracts, offset by $65 million of impairments in 2004 at Field Services and Crescent.
- A $228 million decrease in Operation, Maintenance and Other due primarily to severance costs accrued in 2003 related to workforce reductions and decreased operating and maintenance cost at DENA resulting from cost reduction efforts and the sale of plants in 2004, partially offset by increased costs at Crescent related to increased residential developed lot sales
- A $254 million decrease due to the 2003 write off of goodwill at DENA, most of which related to DENA's trading and marketing business, and
- An $84 million decrease driven by the continued wind-down of DETM and DEM, partially offset by higher commodity prices at Field Services as discussed above.

*Year Ended December 31, 2003 as Compared to December 31, 2002.* Consolidated operating expenses for 2003 increased $9,560 million, compared to 2002. The increase in consolidated operating expenses was driven primarily by impairments and other related charges, and by the same drivers that affected consolidated operating revenues: increased purchase costs for NGLs and the adoption of the final consensus on EITF Issue No. 02-03, and additional expenses due to the acquisition of Westcoast.

**Consolidated Gains on Sales of Investments in Commercial and Multi-Family Real Estate**

Consolidated gains on sales of investments in commercial and multi-family real estate were $192 million in 2004, $84 million in 2003, and $106 million in 2002. For a detailed discussion of this item see the Crescent segment discussion below.

**Consolidated (Losses) Gains on Sales of Other Assets, net**

Consolidated (losses) gains on sales of other assets, net was a loss of $225 million for 2004, a loss of $199 million for 2003, and a gain of $32 million for 2002. The loss in 2004 was due primarily to pre-tax losses on the sale of the Southeast Plants (approximately $360 million) at DENA, and the termination and sale of DETM contracts ($65 million) offset by gains on the sales of two partially completed plants, Moapa ($140 million) and Luna ($40 million) at DENA. The loss for 2003 was primarily comprised of a $208 million loss at DENA primarily related to charges on DETM contracts ($127 million) resulting from the wind-down of DETM's operations, and impairments recorded on assets held for sale, including a 25% undivided interest in the wholly-owned Vermillion facility ($18 million), and stored turbines and related equipment ($66 million). The gain for 2002 was primarily comprised of a $33 million gain on the sale of Duke Energy's remaining water operations.

### Consolidated Operating Income

*Year Ended December 31, 2004 as Compared to December 31, 2003.* For 2004, consolidated operating income increased $3,867 million, compared to 2003. Increased operating income was driven primarily by increased operating income at DENA, as a result of impairments and other related charges in 2003.

*Year Ended December 31, 2003 as Compared to December 31, 2002.* For 2003, consolidated operating income decreased $3,593 million, compared to 2002. Lower operating income was driven primarily by asset impairments and related charges at DENA of $2,903 million, as discussed above.

### Consolidated Other Income and Expenses

Consolidated other income and expenses decreased $282 million for the year ended December 31, 2004 as compared to December 31, 2003. The decrease primarily resulted from the $178 million pre-tax gain on the sale of DENA's 50% interest in Ref-Fuel in 2003 and Natural Gas Transmission's $90 million gain on sales of various investments in 2003, offset by foregone earnings from those investments. The increase in 2003 compared to 2002 was also a result of the gain from the Ref-Fuel sale as discussed above.

### Segment Results

Management evaluates segment performance primarily based on earnings before interest and taxes from continuing operations, after deducting minority interest expense related to those profits (EBIT). On a segment basis, EBIT represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. EBIT excludes discontinued operations. Cash, cash equivalents and short-term investments are managed centrally by Duke Energy, so the gains and losses on foreign currency remeasurement associated with cash balances, and interest income on those balances, are excluded from the segments' EBIT. Management considers segment EBIT to be a good indicator of each segment's operating performance from its continuing operations, as it represents the results of Duke Energy's ownership interest in operations without regard to financing methods or capital structures.

Duke Energy's segment EBIT may not be comparable to a similarly titled measure of another company because other entities may not calculate EBIT in the same manner. Business segment EBIT is summarized in the following table, and detailed discussions follow.

### EBIT by Business Segment

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | Variance 2004 vs 2003 | 2002 | Variance 2003 vs 2002 |
| | | | (in millions) | | |
| Franchised Electric | $ 1,467 | $ 1,403 | $ 64 | $ 1,595 | $ (192) |
| Natural Gas Transmission | 1,310 | 1,317 | (7) | 1,161 | 156 |
| Field Services | 380 | 187 | 193 | 148 | 39 |
| DENA | (535) | (3,341) | 2,806 | 169 | (3,510) |
| International Energy | 222 | 215 | 7 | 102 | 113 |
| Crescent | 240 | 134 | 106 | 158 | (24) |
| Total reportable segment EBIT | 3,084 | (85) | 3,169 | 3,333 | (3,418) |
| Other | (77) | (272) | 195 | (368) | 96 |
| Total reportable segment and other EBIT | 3,007 | (357) | 3,364 | 2,965 | (3,322) |
| Minority interest expense and other[a] | 114 | 27 | 87 | 38 | (11) |
| Interest expense | (1,349) | (1,380) | 31 | (1,097) | (283) |
| Consolidated earnings (loss) from continuing operations before income taxes | $ 1,772 | $(1,710) | $3,482 | $ 1,906 | $(3,616) |

(a) Includes interest income, foreign currency remeasurement gains and losses, additional minority interest expense not allocated to the segment results and inter-segment eliminations.

The amounts discussed below include intercompany transactions that are eliminated in the Consolidated Financial Statements.

**Franchised Electric**

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | Variance 2004 vs 2003 | 2002 | Variance 2003 vs 2002 |
| | | | (in millions) | | |
| Operating revenues | $ 5,069 | $ 4,875 | $ 194 | $ 4,888 | $ (13) |
| Operating expenses | 3,613 | 3,525 | 88 | 3,329 | 196 |
| Gains on sales of other assets, net | 3 | 6 | (3) | — | 6 |
| Operating income | 1,459 | 1,356 | 103 | 1,559 | (203) |
| Other income, net of expenses | 8 | 47 | (39) | 36 | 11 |
| EBIT | $ 1,467 | $ 1,403 | $ 64 | $ 1,595 | $(192) |
| Sales, Gigawatt-hours (GWh) | 82,708 | 82,828 | (120) | 83,783 | (955) |

The following table shows the percentage changes in GWh sales and average number of customers for Franchised Electric for the past two years.

| Increase (decrease) over prior year | 2004 | 2003 | 2002 |
|---|---|---|---|
| Residential sales[a] | 5.1% | (2.3)% | 5.2% |
| General service sales[a] | 3.5% | 0.4% | 2.4% |
| Industrial sales[a] | 1.8% | (5.7)% | (2.4)% |
| Wholesale sales | (26.1)% | 5.1% | 35.4% |
| Total Franchised Electric sales[b] | (0.1)% | (1.1)% | 5.1% |
| Average number of customers | 1.7% | 2.0% | 2.4% |

(a) Major components of Franchised Electric's retail sales.
(b) Consists of all components of Franchised Electric's sales, including retail sales, and wholesale sales to incorporated municipalities and to public and private utilities and power marketers.

*Year Ended December 31, 2004 as Compared to December 31, 2003*

*Operating Revenues.* The increase was driven primarily by:

- A $138 million increase in billed and unbilled fuel revenues driven by increased fuel rates for retail customers, due primarily to increased coal costs
- A $68 million increase in GWh sales to retail customers, due to favorable weather during the period
- A $33 million increase due to continued growth in the number of residential and general service customers in Franchised Electric's service territory
- A $30 million increase due to a rate decrement ordered by the PSCSC and recorded during the third quarter of 2003, partially offset by
- A $50 million decrease in wholesale power revenues, due primarily to lower sales volumes due to limited generation availability resulting from a shortage of coal and increased outages at certain Franchised Electric generation facilities, and
- An $18 million decrease due to sharing of profits from wholesale power sales with customers in North Carolina in 2004.

*Operating Expenses.* The increase was driven primarily by:

- Increased fuel expenses of $127 million, due primarily to increased coal costs and increased sales to retail customers
- Increased nuclear and fossil outage costs of $24 million, driven by increased scope and duration of 2004 nuclear outages compared to 2003 and seven planned maintenance/turbine outages across the fossil fleet in 2004 as compared to two planned maintenance/turbine outages in 2003
- Increased depreciation expense of $16 million, primarily due to additional capital spending and assets placed in service
- Increased donations of $14 million, due to sharing of profits from wholesale power sales with charitable, educational and economic development programs in North Carolina and South Carolina as agreed to with the state utility commission, partially offset by
- Decreased severance expenses of $78 million due to workforce reductions in 2003, and

- Decreased operating and maintenance expenses of $9 million, primarily due to a charge in 2003 for right-of-way maintenance costs, partially offset by increased governance costs in 2004.

*Other Income, net of expenses.* The decrease was driven primarily by:

- A $25 million decrease in the allowance for funds used during construction (AFUDC), due primarily to large maintenance capital projects that were completed and placed in service in 2003, reducing the basis on which AFUDC is calculated, and
- A $15 million decrease in the return on deferred costs related to the purchase of capacity from the joint owners of the Catawba Nuclear Station.

*EBIT.* The increase in 2004 EBIT resulted primarily from increased sales to retail customers due to favorable weather in 2004, continued growth in the number of residential and general service customers in 2004, and severance and right-of-way maintenance charges coupled with the one year rate decrement ordered by the PSCSC during 2003. These changes were partially offset by lower sales to wholesale customers, sharing of profits from wholesale power sales, increased fossil and nuclear outages and increased depreciation expense.

*Matters Impacting Future Franchised Electric Results*

Franchised Electric continues to increase its customer base, maintain low costs and deliver high-quality customer service in the Piedmont Carolinas. The residential and general service sectors are expected to continue to grow. As noted above, wholesale power revenues declined during 2004 due to coal inventory shortages resulting from delivery constraints. Coal deliveries have since improved and Franchised Electric expects to have increased wholesale opportunities as coal inventories increase. Franchised Electric's EBIT growth rate over the next three years is expected to be in the zero to two percent range. Franchised Electric will continue to provide strong cash flows to Duke Energy. Changes in weather, wholesale power market prices, generation availability and changes to the regulatory environment could impact future financial results for Franchised Electric. In addition, Franchised Electric's results will be affected by its flexibility to vary the amortization expenses associated with the North Carolina clean air legislation. Franchised Electric's amortization expense related to this clean air legislation totals $326 million from inception, with $211 million recorded in 2004 and $115 million recorded in 2003.

*Year Ended December 31, 2003 as Compared to December 31, 2002*

*Operating Revenues.* The decrease was driven primarily by:

- An $80 million decrease from lower GWh sales to retail customers due to mild weather, particularly during the summer months of 2003
- A $30 million decrease due to a one year rate decrement ordered by the PSCSC during the third quarter of 2003
- A $28 million decrease in sales to industrial customers, which continued to decline due to the sluggish economy in North Carolina and South Carolina, partially offset by
- An $87 million increase from wholesale power sales, as a result of favorable market conditions. The primary driver was higher prices for natural gas, which increased both the market price and demand for wholesale power, coupled with availability of low cost generation (primarily coal-fired generation for Franchised Electric), and
- A $38 million increase due to continued growth in the number of residential and general service customers in Franchised Electric's service territory.

*Operating Expenses.* The increase was driven primarily by:

- Increased depreciation and amortization expense of $137 million, primarily driven by amortization expense related to North Carolina's clean air legislation, which totaled $115 million
- Increased severance expenses of $42 million due to additional workforce reductions in 2003
- Charges in 2003 of $40 million for right-of-way maintenance costs, partially offset by
- Insurance recoveries in 2002 of $25 million related to injuries and damages claims
- Decreased storm costs of $59 million, with $30 million incurred in 2003 compared to $89 million associated with an ice storm in December 2002, and
- Decreased purchased power expense of $12 million, driven by lower demand from retail customers due to the milder weather.

*EBIT.* EBIT for 2003 decreased $192 million, compared to 2002, due primarily to unfavorable weather, the one year South Carolina rate decrement and lower sales to industrial customers, coupled with increased depreciation and amortization expense, severance expenses and right-of-way maintenance costs. These changes were partially offset by increased wholesale power sales, continued growth in the number of residential and general service customers, and lower storm and purchased power expenses.

**Natural Gas Transmission**

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | Variance 2004 vs 2003 | 2002 | Variance 2003 vs 2002 |
| | | | (in millions) | | |
| Operating revenues | $3,290 | $3,197 | $ 93 | $2,464 | $733 |
| Operating expenses | 2,033 | 1,969 | 64 | 1,420 | 549 |
| Gains on sales of other assets, net | 17 | 7 | 10 | — | 7 |
| Operating income | 1,274 | 1,235 | 39 | 1,044 | 191 |
| Other income, net of expenses | 58 | 125 | (67) | 148 | (23) |
| Minority interest expense | 22 | 43 | (21) | 31 | 12 |
| EBIT | $1,310 | $1,317 | $ (7) | $1,161 | $156 |
| Proportional throughput, TBtu[a] | 3,332 | 3,362 | (30) | 3,160 | 202 |

(a) Trillion British thermal units. Revenues are not significantly impacted by pipeline throughput fluctuations since revenues are primarily composed of demand charges.

*Year Ended December 31, 2004 as Compared to December 31, 2003*

*Operating Revenues.* The increase was driven primarily by:

- A $171 million increase due to foreign exchange rates favorably impacting revenues from the Canadian operations as a result of the strengthening Canadian dollar (partially offset by currency impacts to expenses)
- A $62 million increase from recovery of higher natural gas commodity costs, resulting from higher natural gas prices that are passed through to customers without a mark-up at Union Gas. This revenues increase is offset in expenses.
- A $40 million increase from completed and operational pipeline expansion projects in the United States, partially offset by
- A $95 million decrease as a result of the sale of Empire State Pipeline in February 2003 and Pacific Natural Gas (PNG) in December 2003, and
- An $80 million decrease in gas distribution revenues at Union Gas resulting from lower gas usage in the power market due to unfavorable weather.

*Operating Expenses.* The increase was driven primarily by:

- A $124 million increase caused by foreign exchange impacts (offset by currency impacts to revenues)
- A $62 million increase related to increased natural gas prices at Union Gas. This amount is offset in revenues
- A $52 million increase resulting from the favorable resolution in 2003 of various contingencies primarily related to a capital project and outstanding ad valorem and franchise tax issues from prior state audits
- A $17 million increase associated with the pipeline expansion projects placed in service
- A $14 million increase in depreciation primarily due to an increase in the depreciation rate and the addition of two major projects in the Western Canadian operations, partially offset by
- An $80 million decrease as a result of operations sold in 2003 as discussed above
- A $63 million decrease in the cost of gas sold for distribution at Union Gas, due primarily to reduced volumes
- A $29 million decrease due to severance costs in 2003, and
- A $23 million decrease primarily related to the 2004 resolution of ad valorem tax issues in various states.

*Other Income, net of expenses.* The decrease was driven primarily by:

- A $90 million decrease as a result of prior year gains on sales, primarily the gain on the sale of Natural Gas Transmission's interests in Northern Border Partners L.P. in January 2003, Alliance Pipeline and the Aux Sable liquids plants in April 2003, and Foothills Pipe Lines Ltd in August 2003
- A $22 million decrease AFUDC (equity component) due to lower capital spending in 2004

- An $18 million decrease in equity earnings as a result of investments sold in 2003, partially offset by
- A $36 million increase resulting from the 2003 negative settlement of hedges related to foreign currency exposure
- An increase of $16 million in equity earnings of Gulfstream Natural Gas System, LLC, resulting from higher revenues and volumes due to fuel switching during the unusually active hurricane season in Florida in 2004, and
- A $16 million increase from 2004 gains on the sale of equity investments, primarily due to resolution of contingencies related to prior year sales.

*Minority Interest Expenses.* The decrease was driven primarily by the sale of PNG in December 2003, as well as lower earnings on Maritimes & Northeast Pipeline.

*EBIT.* EBIT decreased primarily as a result of gains from sales of equity investments recorded in the prior year and foregone earnings from the investments sold. Those decreases were mostly offset by earnings from expansion projects and foreign exchange EBIT impacts from the strengthening Canadian currency.

*Matters Impacting Future Natural Gas Transmission Results*

Natural Gas Transmission plans to continue earnings growth through capital efficient expansions in existing markets, optimization of existing systems, and organizational efficiencies and cost control. Natural Gas Transmission expects modest annual EBIT growth over the next three years from its 2004 EBIT, generally consistent with growth in demand. Demand for natural gas is expected to grow two to three percent in DEGT's key markets. The average contract life for the U.S. pipelines is eight years. Changes in the Canadian dollar, weather, throughput and the ability to renew service contracts would impact future financial results at Natural Gas Transmission.

In February 2005, Duke Energy executed an agreement with ConocoPhillips whereby Duke Energy has agreed to transfer a 19.7% interest in DEFS to ConocoPhillips for direct and indirect monetary and non-monetary consideration of approximately $1.1 billion. Upon closing of this transaction, DEFS expects to transfer its Canadian assets to Duke Energy's Natural Gas Transmission segment. Also as part of this transaction, Natural Gas Transmission expects to receive assets in Alberta, Canada from ConocoPhillips. This transaction, which is subject to customary U.S. and Canadian regulatory approval, is expected to close in the latter half of 2005.

*Year Ended December 31, 2003 as Compared to December 31, 2002*

*Operating Revenues.* This increase was driven primarily by:

- A $466 million increase in transportation, storage and distribution revenue in January and February 2003 from assets acquired or consolidated as a part of the Westcoast acquisition in March 2002 (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions")
- A $177 million increase due to foreign exchange favorably impacting revenues from the Canadian operations as a result of the strengthening Canadian dollar (partially offset by currency impacts to expenses)
- An $81 million increase from recovery of natural gas commodity costs that are passed through to customers without a mark-up at Union Gas. This amount is offset by a corresponding increase in expenses.
- A $31 million increase from completed and operational business expansion projects in the U.S., partially offset by
- A $58 million decrease from operations sold in 2003 and the fourth quarter of 2002.

*Operating Expenses.* This increase was driven primarily by:

- A $319 million increase in transportation, storage, and distribution expenses in January and February 2003 from assets acquired or consolidated as a part of the Westcoast acquisition in March 2002
- A $132 million increase caused by foreign exchange impacts (partially offset by currency impacts to revenues)
- An $81 million increase related to increased natural gas prices at Union Gas. This amount is offset by a corresponding increase in revenues.
- A $20 million increase from 2003 severance charges related to workforce reductions, partially offset by
- A $38 million decrease from operations sold in the fourth quarter of 2002 and in 2003.

For the year ended December 31, 2003, Natural Gas Transmission's operating expenses increased approximately 39% when compared to the same period in 2002, while operating revenues increased approximately 30%. The difference was due to the Westcoast operations that were acquired in March 2002. The operating expenses, as a percentage of operating revenues, of the acquired Westcoast natural gas distribution business, are greater than the previously owned natural gas transmission business. Gas commodity costs related to the Westcoast distribution business are recovered from customers by increasing revenues by the amount of gas commodity costs expensed (i.e. flowed through to customers with no incremental profit).

*Other Income, net of expenses.* This decrease was driven primarily by:

- A $36 million decrease from negative foreign exchange impacts in 2003, due to the settlement of hedges related to foreign currency exposure
- A $33 million decrease in equity earnings associated with the sold investments
- A $28 million decrease due to a construction fee received in 2002 from an affiliate related to the successful completion of Gulfstream, 50% owned by Duke Energy which went into service in May 2002, partially offset by
- A $58 million increase in gains from the sale of various equity investments in 2003, and
- A $17 million increase in AFUDC related to additional capital projects.

*Minority Interest Expense.* Minority interest expense increased in 2003 compared to 2002. This resulted from the recognition of a full year of minority interest expense in 2003, versus only ten months during 2002, from less than wholly owned subsidiaries acquired in the March 2002 acquisition of Westcoast.

*EBIT.* EBIT increased in 2003 compared to 2002, due primarily to incremental EBIT related to assets acquired or consolidated as part of the March 2002 acquisition of Westcoast, gains on asset sales, and business expansion projects in the U.S. These items were partially offset by earnings in 2002 from operations that were sold in the fourth quarter of 2002 and during 2003, and 2003 severance charges in excess of 2002 amounts.

**Field Services**

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | Variance 2004 vs 2003 | 2002 | Variance 2003 vs 2002 |
| | | | (in millions) | | |
| Operating revenues | $10,104 | $8,595 | $1,509 | $5,952 | $2,643 |
| Operating expenses | 9,531 | 8,360 | 1,171 | 5,817 | 2,543 |
| Gains (Losses) on sales of other assets, net | 2 | (4) | 6 | — | (4) |
| Operating income | 575 | 231 | 344 | 135 | 96 |
| Other income, net of expenses | 37 | 67 | (30) | 60 | 7 |
| Minority interest expense | 232 | 111 | 121 | 47 | 64 |
| EBIT | $ 380 | $ 187 | $ 193 | $ 148 | $ 39 |
| *Natural gas gathered and processed/transported, TBtu/d*[a] | 7.3 | 7.4 | (0.1) | 7.9 | (0.5) |
| NGL production, MBbl/d[b] | 363 | 353 | 10 | 379 | (26) |
| Average natural gas price per MMBtu[c] | $ 6.14 | $ 5.39 | $ 0.75 | $ 3.22 | $ 2.17 |
| Average NGL price per gallon[d] | $ 0.68 | $ 0.53 | $ 0.15 | $ 0.38 | $ 0.15 |

(a) Trillion British thermal units per day
(b) Thousand barrels per day
(c) Million British thermal units
(d) Does not reflect results of commodity hedges

*Year Ended December 31, 2004 as Compared to December 31, 2003*

*Operating Revenues.* The increase was primarily driven by:

- A $870 million increase due primarily to a $0.15 per gallon increase in average NGL prices
- A $590 million increase due primarily to a $0.75 per MMBtu increase in average natural gas prices
- A $51 million increase from trading and marketing net margin, due primarily to natural gas asset based trading and marketing price volatility
- A $45 million increase attributable to a $10.29 per barrel increase in average condensate prices to $41.37 during 2004 from $31.08 during 2003

- A $35 million increase related to higher transportation, storage and processing fees which was primarily due to higher fees from processing contracts, partially offset by
- A $44 million decrease related to the impact of cash flow hedging, which reduced revenues by approximately $242 million for the year ended December 31, 2004 and by $198 million for the year ended December 31, 2003, as compared to what revenue would have been without any hedging, and
- A $30 million decrease related to lower NGL and raw natural gas sales volume, partially offset by an increase in wholesale propane marketing activity primarily due to higher propane prices, and the acquisition of gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips ("COP Acquisition"). Although production volumes increased as a result of processing economics and the COP Acquisition, sales volumes decreased as a result of producers marketing their NGLs on their own behalf.

*Operating Expenses.* The increase was driven primarily by:

- A $1,175 million increase due to higher average costs of raw natural gas supply which was due primarily to an increase in average NGL and natural gas prices
- A $18 million increase related to impairment charges associated with a planned shut down of a specific plant and a disposal of certain assets
- A $20 million increase related primarily to an increase in wholesale propane marketing activity and the acquisition of gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips partially offset by lower purchased raw natural gas supply volume, partially offset by
- A $25 million decrease in operating, and general and administrative expenses, primarily due to severance charges and other employee related expenditures in 2003 not experienced in 2004, lower repairs and maintenance, and environmental expenses in 2004, partially offset by an increase related to Field Services' Sarbanes-Oxley compliance costs.

*Other Income, Net of Expenses.* The decrease was driven primarily by:

- A $23 million decrease due to impairment charges in 2004 related to management's assessment of the recoverability of certain equity method investments
- A $13 million decrease due to the gains on sales of equity method investments in 2003, partially offset by
- A $7 million increase in equity earnings primarily due to increased earnings from equity method investments.

*Minority Interest Expense.* Minority interest expense increased in 2004 compared to 2003 due to increased earnings from DEFS, Duke Energy's joint venture with ConocoPhillips. The increase was not proportionate to the increase in Field Services' earnings, as the Field Services segment includes the results of incremental hedging activities contracted at the Duke Energy corporate level that are not included in DEFS' results.

*EBIT.* The increase in EBIT in 2004 compared to 2003 resulted primarily from the favorable effects of commodity prices and improved results from trading and marketing activities, partially offset by NGL and raw natural gas sales volume declines and impairments. The full impact from the effects of commodity prices were not realized as some sales volumes were previously hedged at prices different than actual market prices at settlement.

*Matters Impacting Future Field Services Results*

Field Services has developed significant size and scope in natural gas gathering and processing and NGL marketing and plans to focus on operational excellence and organic growth. Field Services' revenues and expenses are significantly dependent on prevailing commodity prices for NGLs and natural gas, and past and current trends in price changes of these commodities may not be indicative of future trends. Field Services anticipates that current price levels will continue to stimulate drilling and help to offset declining raw natural gas supplies. Although the prevailing price of natural gas has less short term significance to its operating results than the price of NGLs, in the long term, the growth and sustainability of Field Services' business depends on natural gas prices being at levels sufficient to provide incentives and capital for producers to increase natural gas exploration and production.

In February 2005, Duke Energy executed an agreement with ConocoPhillips whereby Duke Energy has agreed to transfer a 19.7 percent interest in DEFS to ConocoPhillips for direct and indirect monetary and non-monetary consideration of approximately $1.1 billion. In connection with this transaction, DEFS expects to transfer its Canadian assets to Duke Energy's Natural Gas Transmission segment and receive certain U.S. Midstream assets or cash from ConocoPhillips. Upon completion of this transaction, DEFS will be owned 50 percent by Duke Energy and 50 percent by ConocoPhillips. As a result, Duke Energy expects to account for its investment in DEFS using the equity method subsequent to closing of the transaction. This transaction, which is subject to customary U.S. and Canadian regulatory approval, is expected to close in the latter half of 2005. This transaction is estimated to result in a pretax gain to Field Services of approximately $600 million. Additionally, in February 2005, DEFS sold its general partnership in TEPPCO for approximately $1.1 billion and Duke Energy sold its limited partnership interest in TEPPCO for approximately $100 million to Enterprise GP Holdings L.P., an unrelated third party. These transactions closed in the first quarter of 2005 and are estimated to result in a pretax gain to Field Services of approximately $900 million (net of approximately $330 million of minority interest).

As a result, Duke Energy expects to deconsolidate its investment in DEFS subsequent to the closing of the sale of its 19.7% interest to ConocoPhillips. During the first quarter of 2005 Duke Energy has discontinued hedge accounting for certain 2005 and 2006 contracts held by Duke Energy related to Field Services' commodity risk, which were previously accounted for as cash flow hedges. As a result of the discontinuation of hedge accounting treatment, approximately $140 million of pretax deferred losses in Accumulated Other Comprehensive Income (AOCI) related to these contracts have been charged against earnings by Duke Energy in the first quarter of 2005, which will impact Field Services' segment EBIT. On a prospective basis, these contracts will be accounted for under the MTM Model, which will impact Other EBIT.

Future revenues, gas purchases and EBIT will continue to be sensitive to commodity prices that have historically been cyclical and volatile. Field Services equity NGL position for 2005 was approximately 64% hedged as of December 31, 2004 at an average crude price equivalent of $38 per barrel. After considering the impacts of hedging, Field Services exposure to a one cent per gallon change in the average price of NGLs is $5 million for 2005. This figure does not include the effects of discontinued hedge accounting for certain 2005 and 2006 contracts, previously accounted for as cash flow hedges. During the first quarter of 2005, these contracts began to be accounted for under the MTM Model and, as a result, Duke Energy's earnings for 2005 and 2006 will be subject to more volatility.

Field services operating, and general and administrative costs are expected to increase in 2005, primarily due to asset integrity work and financial process improvements planned during the year. This increase is not expected to have a material effect on Field Services' facility operating costs in 2005.

There are many important factors that could cause actual results to differ materially from the expectations expressed. Management can provide no assurances regarding the impact of future commodity prices or drilling activity.

*Year Ended December 31, 2003 as Compared to December 31, 2002*

*Operating Revenues.* The increase was driven primarily by:

- A $2,200 million increase due primarily to a $2.17 per MMBtu increase in average natural gas prices
- A $1,180 million increase due primarily to a $0.15 per gallon increase in average NGL prices, partially offset by
- A $120 million decrease related to lower throughput of raw natural gas supply
- A $395 million decrease related to lower NGL production, and
- A $179 million decrease due to the impacts of cash flow hedging which reduced revenues by approximately $198 million for the year ended December 31, 2003 and by $19 million for the year ended December 31, 2002, as compared to what revenue would have been without any hedging.

*Operating Expenses.* The increase was primarily driven by:

- A $2,920 million increase due to higher costs of raw natural gas and NGL supply
- A $37 million increase related to other factors, including severance charges in 2003 and other employee related expenditures, partially offset by
- A $455 million decrease due to lower throughput volumes, and
- A $53 million decrease in 2003 operating expenses was due to 2002 charges related to Field Services internal review of balance sheet accounts ($37 million at Duke Energy's 70% share), which may be related to corrections of accounting errors in periods prior to 2002. These adjustments were made in the following five categories: operating expense accruals; gas inventory valuations; gas imbalances; joint venture and investment account reconciliations; and other balance sheet accounts and were immaterial to Duke Energy's reported results.

*Minority Interest Expense.* Minority interest expense at Field Services increased in 2003 compared to 2002 due to increased earnings from DEFS. The increase in minority interest expense was not proportionate to the increase in Field Services' earnings as the Field Services segment includes the results of incremental hedging activities contracted at the Duke Energy corporate level that are not included in DEFS results.

*EBIT.* EBIT for 2003 increased compared to 2002 as a result of better pricing and other factors discussed above.

**DENA**

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | Variance 2004 vs 2003 | 2002 | Variance 2003 vs 2002 |
| | | | (in millions) | | |
| Operating revenues | $ 2,361 | $ 4,321 | $(1,960) | $ 1,552 | $ 2,769 |
| Operating expenses | 2,690 | 7,767 | (5,077) | 1,507 | 6,260 |
| Losses on sales of other assets, net | (248) | (208) | (40) | — | (208) |
| Operating (loss) income | (577) | (3,654) | 3,077 | 45 | (3,699) |
| Other income, net of expenses | 12 | 206 | (194) | 81 | 125 |
| Minority interest benefit | (30) | (107) | 77 | (43) | (64) |
| EBIT | $ (535) | $ (3,341) | $ 2,806 | $ 169 | $(3,510) |
| Actual plant production, GWh(a)(b) | 21,884 | 24,046 | (2,162) | 24,962 | (916) |
| Net proportional megawatt capacity in operation | 9,890 | 15,820 | (5,930) | 14,157 | 1,663 |

(a) Includes plant production from plants accounted for under the equity method
(b) Excludes discontinued operations

*Year Ended December 31, 2004 as Compared to December 31, 2003*

*Operating Revenues.* The decrease was driven primarily by:

- A $1,691 million decrease from lower natural gas sales volumes, due primarily to the continued wind down of DETM's operations. This decrease was partially offset by approximately $73 million from higher average natural gas prices realized in the current year
- A $309 million reduction in power generation revenues, due primarily to lower average power prices realized from hedging activities and lower volumes due primarily to the sale of the Southeast Plants
- $25 million in lower net trading margins. In 2004, DENA recognized $25 million negative net trading margins, contracts that were being accounted for as normal purchases and normal sales.

*Operating Expenses.* The decrease was driven primarily by:

- A $3,157 million decrease from 2003 impairments and other related charges, including $2,903 million of impairments, primarily related to DENA's Southeast Plants and its partially completed western plants, disqualification of certain hedges that were related to the impaired plants and goodwill impairment related to the trading and marketing business of $254 million
- A $1,707 million decrease from lower natural gas purchase volumes, due primarily to the continued wind down of DETM's operations. This decrease was partially offset by approximately $90 million from higher average natural gas prices realized in the current year
- $184 million of lower general and administrative expense, primarily due to the impact of workforce reductions and associated office costs, travel and other benefits, reduced consulting costs and lower bad debt expense. A 2003 $28 million Commodity Futures Trading Commission (CFTC) settlement ($17 million net of minority interest expense) and 2003 severance costs of $10 million also contributed to a favorable variance in general and administrative expense
- A $113 million ($108 million net of minority interest expense) decrease in operating expenses from a gain related to the settlement of the Enron bankruptcy proceedings in April 2004
- $74 million of lower depreciation expense, primarily due to the sale of the Southeast Plants
- A $27 million decrease in operations and maintenance expense, due primarily to the sale of the Southeast Plants and reduced costs from renegotiated outsourcing agreements, partially offset by two plants entering into commercial operation late in the second quarter of 2003, partially offset by
- A $23 million reduction in plant fuel costs due primarily to lower volumes as a result of the sale of the Southeast Plants, and
- A $105 million increase in operating expenses from a charge related to the California and Western U.S. energy markets settlement in June 2004 (see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies").

*Losses on Sales of Other Assets, net.* Losses on sales of other assets for the year ended December 31, 2004 were due primarily to an approximate $360 million pre-tax loss associated with the sale of DENA's Southeast Plants and approximately $65 million of pre-tax losses associated with the sales and terminations of DETM contracts. Partially offsetting these losses in 2004 were approximately $180 million of pre-tax gains associated with the sales of two DENA partially completed western plants (Luna and Moapa). (See Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions.".) Losses on sales of other assets for 2003 were $208 million due primarily to an $18 million pre-tax loss on the sale of the 25% net interest in the Vermillion facility, a $66 million pre-tax loss on the sale of turbines and $127 million of DETM pre-tax charges related to the sale of contracts.

*Other Income, net of expenses.* The decrease in other income, net of expenses was due primarily to the $178 million pre-tax gain in 2003 from the sale of DENA's 50% interest in Ref-Fuel and the associated foregone equity earnings of $22 million.

*Minority Interest Benefit.* Minority interest benefit decreased due primarily to more favorable 2004 results at DETM as compared to 2003 as a result of the DETM wind-down of operations.

*EBIT.* EBIT increased primarily as a result of the decreased losses from impairments and other related charges, lower plant depreciation and operating expenses from the 2004 sale of the Southeast Plants and lower general and administrative expense. These increases were partially offset by reduced gross margin from lower net sales, net trading margins and values realized from hedge positions, in addition to increased losses on sales of assets, as outlined above.

*Matters Impacting Future DENA Results*

Duke Energy believes merchant energy will play a vital role in meeting the United States' energy demand. A key objective for 2005 is to position DENA to be a successful merchant operator. During 2004, DENA's business model changed to focus on selling fixed capacity contracts in addition to volume based sales and purchases. Duke Energy is pursuing various options to create a sustainable business model for DENA, including consideration of potential business partners. A desirable business model would include fuel and geographic diversity, sufficient size and scope for a substantial market presence and would enable DENA to better withstand the cyclical nature of the industry. Depending on the option selected, there is a risk that material impairments could be recorded, including the potential disqualification of certain contracts and the recognition of unrealized loss associated with DENA power forward sales contracts designated under the normal purchases and normal sales exemption which totaled approximately $900 million as of December 31, 2004. This unrealized loss represents the difference in the normal purchases and normal sales contract prices compared to the forward market prices of power and is partially offset by unrealized gains on natural gas positions of approximately $800 million. (For more information see Commodity Price Risk discussion under Quantitative and Qualitative Disclosures About Market Risk,).

For 2005, DENA expects to significantly reduce its EBIT loss through additional cost savings, and higher gross margins. DENA's marketing efforts in 2005 will focus on contracting capacity and energy production from its plants.

*Year Ended December 31, 2003 as Compared to December 31, 2002*

*Operating Revenues.* The increase was driven primarily by:

- A $3,025 million increase related to the January 1, 2003 adoption of the final consensus on EITF Issue No. 02-03. See earlier discussion under "Consolidated Operating Revenues"
- An increase in net trading margin driven by less unfavorable market changes in correlation and volatility in 2003 as compared to 2002, partially offset by a $76 million increase in 2002 from the appreciation of the fair value of the mark-to-market portfolio as a result of applying improved and standardized valuation modeling techniques to all North American regions, partially offset by
- A $346 million reduction in overall power revenues, due primarily to $299 million decrease resulting from lower power prices and a $47 million decrease due to volumes delivered due to decreased demand.

*Operating Expenses and Impairments.* The increase was driven primarily by:

- A $3,025 million increase due primarily to the adoption of the final consensus on EITF Issue No. 02-03, as described earlier
- A $2,928 million increase due to asset impairments and other related charges related to current market conditions and strategic actions taken by management. For 2003 these charges totaled $3,157 million and related to $2,903 million of impairments, primarily on DENA's Southeast Plants and its partially completed western plants, and disqualification of certain hedges that were related to the impaired assets; and goodwill impairment related to the trading and marketing business of $254 million. These amounts were offset by $229 million of charges taken in 2002 comprised of provisions for the termination of certain turbines on order and the write-down of other uninstalled turbines of $121 million, the write-off of site development costs (primarily in California)

of $31 million, partial impairment of a merchant plant of $31 million, a charge of $24 million for the write-off of an information technology system and demobilization costs related to the deferral of three partially completed western plants $22 million.

- A $32 million increase in overall gas costs due primarily to higher gas prices
- A $62 million increase in other plant related operations, maintenance, and depreciation due primarily to increased costs associated with projects that entered into commercial operation during 2002 and 2003, and
- A $117 million increase in other general and administrative expenses due primarily to a CFTC settlement in 2003 of $28 million ($17 million at Duke Energy's 60% share) and the release of incentive accruals in 2002 of $89 million.

*Losses on Sales of Other Assets, net.* Losses on sales of other assets for 2003 were $208 million due primarily to an $18 million loss on the sale of the 25% net interest in the Vermillion facility, a $66 million loss on the sale of turbines and DETM charges related to the sale of contracts of $127 million.

*Other Income, net of expenses.* Other income, net of expenses increased in 2003, compared to 2002. The increase was driven primarily by:

- A $178 million increase due to a gain on the sale of DENA's 50% ownership interest in Ref-Fuel to Highstar Renewable Fuels LLC in 2003, partially offset by
- A $33 million decrease due to 2002 settlements received on disputed items at two generating facilities and interest income related to a note receivable associated with the sale of an interest in a generating facility in 2002, and
- Remaining decrease due primarily to lower equity earnings from Duke/UAE Ref Fuel.

*Minority Interest Benefit.* Minority interest benefit increased in 2003 compared to 2002, due to increased losses at DETM.

*EBIT.* EBIT for 2003 decreased compared to 2002. The decrease was due primarily to those factors discussed above: plant impairments, disqualification of certain hedges, the wind down of DETM, the write-off of goodwill, narrowed spark spreads, and increases in 2002 related to the appreciation of the fair value of the mark-to-market portfolio.

**International Energy**

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | Variance 2004 vs 2003 | 2002 | Variance 2003 vs 2002 |
| | | | (in millions) | | |
| Operating revenues | $ 619 | $ 597 | $ 22 | $ 743 | $ (146) |
| Operating expenses | 462 | 426 | 36 | 716 | (290) |
| Losses on sales of other assets, net | (3) | — | (3) | — | — |
| Operating income | 154 | 171 | (17) | 27 | 144 |
| Other income, net of expenses | 78 | 57 | 21 | 85 | (28) |
| Minority interest expense | 10 | 13 | (3) | 10 | 3 |
| EBIT | $ 222 | 215 | 7 | 102 | 113 |
| Sales, GWh | 17,776 | 16,374 | 1,402 | 18,350 | (1,976) |
| Net proportional megawatt capacity in operation[a] | 4,139 | 4,121 | 18 | 3,917 | 204 |

(a) Excludes discontinued operations

*Year Ended December 31, 2004 as Compared to December 31, 2003*

*Operating Revenues.* The increase was driven primarily by:

- A $32 million increase due to the fourth quarter 2003 completion of the 160 MW Planta Arizona expansion in Guatemala
- A $22 million increase in volumes due to higher electricity dispatch in Ecuador as a result of unplanned outages at competing generators
- A $20 million increase in Brazil resulting from higher contracted sales prices of $26 million which were positively impacted by inflation adjustments primarily offset by the impact of a 2003 regulatory audit revenue adjustment
- A $12 million increase due to higher electricity prices caused by low water availability in Peru

- A $12 million increase due to favorable exchange rates primarily in Brazil, partially offset by
- A $48 million decrease in Guatemala and El Salvador due to decreased cross border power marketing activity resulting from unfavorable market conditions, and
- A $33 million decrease in natural gas sales due to the termination of a natural gas sales contract from the liquefied natural gas business in 2003.

*Operating Expenses.* The increase was driven primarily by:

- A $23 million increase due to the fourth quarter 2003 completion of the 160 megawatt (MW) Planta Arizona expansion in Guatemala as discussed above
- A $21 million increase in electricity generation costs resulting from higher levels of dispatch in Ecuador as described above
- An $18 million increase due to a reserve reduction in 2003 related to the early termination of a natural gas sales contract from the liquefied natural gas business
- A $17 million increase in Peru power purchases to satisfy sale contract requirements caused by decreased generation as a result of low water availability
- A $14 million increase due to general and administrative expenses primarily due to higher corporate allocations and Sarbanes-Oxley compliance costs
- A $12 million increase in Brazil due primarily to increased transmission fees and other costs offset by an environmental charge recorded in 2003 and a reduction in the environmental reserves in 2004, partially offset by
- A $42 million decrease in spot market purchases in Guatemala and El Salvador due to decreased cross border power marketing activity
- A $37 million decrease in natural gas sales purchases due to the termination of a natural gas sales contract from the LNG business in 2003 and
- A $13 million charge associated with the disposition of the ownership share in the Compañia de Nitrógeno de Cantarell, S.A. de C.V. (Cantarell) nitrogen facility in Mexico.

*Other Income, net of expenses.* The increase was primarily the result of:

- An $11 million increase due to a 2003 adjustment related to revenue recognition for the Cantarell equity investment, and
- A $6 million increase due to favorable netback pricing at National Methanol Company

*EBIT.* EBIT increased modestly in 2004 compared to 2003. The slight increase was due to the factors described above.

*Matters Impacting Future International Energy Results*

International Energy's current strategy is focused on selectively growing its Latin American power generation business while continuing to maximize the returns and cash flow from its current portfolio.

EBIT results for International Energy are sensitive to changes in hydrology, power supply, power demand and fuel prices. Regulatory matters can also impact EBIT results, as well as impacts from fluctuations in exchange rates, most notably the Brazilian Real.

During 2005, Duke Energy's Brazilian affiliate may participate in the next regulated auction for the sale of power to the distribution companies. The auction process provides for 8 year contracts with delivery commencing in 2008 and 2009. The outcome of these auctions could impact International Energy's EBIT results for the years 2008 and beyond.

International Energy owns a 50% joint venture interest in Compañía de Servicios de Compresión de Campeche, S.A. de C.V. (Campeche). Campeche operates a natural gas compression facility in the Cantarell oil field in the Gulf of Mexico. Campeche project revenues are generated from the gas compression services agreement (GCSA) with the Mexican national oil company (PEMEX). The current five year GCSA expires on October 31, 2006 and PEMEX has the option to renew the GCSA for an additional four years. Campeche has made a renewal offer to PEMEX that has been initially rejected; however, discussions continue with PEMEX regarding renewal of the contract or other possible arrangements. If it is determined that the renewal will not take place or another economically viable arrangement is not found, the value of International Energy's equity investment in Campeche would decline and such investment would be written down to its resulting fair value. International Energy's estimated maximum exposure to this risk is potential impairment or other charges of $70 million.

Certain of International Energy's long-term sales contracts and long-term debt in Brazil contain inflation adjustment clauses. While this is favorable to revenue in the long run, as International Energy's contract prices are adjusted, there is an unfavorable impact on interest expense resulting from revaluation of International Energy's outstanding local currency debt. In general, interest rates were lower in 2004 than in 2003 and the resulting impact on contract revenues and interest expense in 2004 was not as great as in 2003.

*Year Ended December 31, 2003 as Compared to December 31, 2002*

*Operating Revenues.* The decrease was driven primarily by:

- A $91 million nonrecurring favorable impact on 2002 revenues as a result of a Brazilian regulatory ruling in March 2002 that affected all Brazilian energy market participants and finalized the methodology to calculate revenues and expenses related to the 2001 electricity rationing, which is offset in operating expenses
- A change in methodology in Peru to reflect a netting of the volumes transferred to/from the electricity grid in 2003 resulting in a $57 million revenue reduction, which is offset in expense
- Lower revenues of $35 million in El Salvador as a result of a power sales contract not being renewed by a counterparty
- Lower LNG sales of $33 million, due primarily to the termination of a gas sales contract
- Unfavorable exchange rate impacts resulting in a decrease of $10 million in Brazil and Argentina, partially offset by
- An increase of $35 million related primarily to favorable recontracting terms on electricity sales contracts in Brazil
- An increase of $25 million as a result of the completion of the 160 MW expansion in Guatemala, and
- Increases to revenues and receivables for adjustments of $11 million as a result of a regulatory audit in Brazil.

*Operating Expenses.* The decrease was driven primarily by:

- A $91 million nonrecurring favorable impact on 2002 operating expenses as a result of a Brazilian regulatory ruling in March 2002 that affected all Brazilian energy market participants and finalized the methodology to calculate revenues and expenses related to the 2001 electricity rationing, which is offset in operating revenues
- A $75 million write-down in 2002 for the cancellation of capital projects in Brazil and Bolivia
- A change in methodology in Peru to reflect a netting of the volumes transferred to/from the electricity grid in 2003 resulting in a $57 million expense reduction, which is offset in revenue
- A $26 million charge and reserve for environmental settlements in Brazil
- Lower expenses in the LNG business due to a $40 million charge recorded in 2002 for estimated probable losses due the early termination of a natural gas sales contract and $31 million in lower gas purchases
- Lower expenses of $19 million in El Salvador as a result of reduced contract sales volumes
- Cost savings of $17 million from lower International Energy corporate expenses, partially offset by
- Higher operating expenses of $22 million due to the completion of the 160 MW expansion in Guatemala.

*Other Income, net of expenses.* The decrease was primarily the result of:

- A $43 million decrease in equity investment income in Mexico due to a change in revenue recognition, increased repair costs, lower revenue due to downtime, and currency translation, partially offset by
- An $11 million increase in equity investment income at National Methanol Company due to favorable product prices.

*EBIT.* The increase was due primarily to the absence of $75 million in charges for project cancellations that occurred in 2002, favorable contract terms on the renewal of the initial contracts in Brazil, and increased volumes in Central America due to the completion of expansion projects. Other principal drivers included net increases of $40 million from the LNG business, $17 million due to lower administrative expenses, and $11 million on the equity investment income for National Methanol Company, offset by changes in revenue recognition and operating results in Mexico, as noted above.

**Crescent**

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | Variance 2004 vs 2003 | 2002 | Variance 2003 vs 2002 |
| | | | (in millions) | | |
| Operating revenues | $437 | $284 | $153 | $226 | $ 58 |
| Operating expenses | 393 | 231 | 162 | 177 | 54 |
| Gains on sales of investments in commercial and multi-family real estate | 192 | 84 | 108 | 106 | (22) |
| Operating income | 236 | 137 | 99 | 155 | (18) |
| Other income, net of expenses | 3 | — | 3 | 1 | (1) |
| Minority interest (benefit) expense | (1) | 3 | (4) | (2) | 5 |
| EBIT | $240 | $134 | $106 | $158 | $(24) |

*Year Ended December 31, 2004 as Compared to December 31, 2003*

*Operating Revenues.* The increase was driven primarily by a $160 million increase in residential developed lot sales, due to increased sales at the LandMar division in northeastern and central Florida, the Palmetto Bluff project in Bluffton, South Carolina, The Sanctuary project near Charlotte, North Carolina, the Lake James projects in northwestern North Carolina and the Lake Keowee projects in northwestern South Carolina.

*Operating Expenses.* The increase was driven primarily by a $101 million increase in the cost of residential developed lot sales, due to increased developed lot sales at the projects noted above, $50 million in impairments and other related charges (net of $12 million minority interest as discussed below) related to Twin Creeks, Texas and Payson, Arizona residential development projects and a $26 million increase in corporate administrative expense as a result of increased incentive compensation tied to increased operating results. (See Note 12 to the Consolidated Financial Statements, "Impairments, Severance, and Other Related Charges" for further discussion of Crescent's impairments.)

*Gains on Sales of Investments in Commercial and Multi-Family Real Estate.* The increase was driven primarily by:

- A $31 million increase in commercial project sales, resulting primarily from the sale of a commercial project in the Washington, D.C. area in March 2004
- A $63 million increase in real estate land sales due primarily to the sale of the Alexandria and Arlington land tracts in the Washington, D.C. area in 2004, and
- A $16 million increase in land management or "legacy" land sales, due to several large sales closed in the first quarter of 2004.

*Minority Interest (Benefit) Expense.* The increase in minority interest benefit is primarily due to $12 million of benefit related to impairment and bad debt charges at the Payson, Arizona project as noted above offset by an additional $8 million in minority interest expense related to increased earnings from the LandMar division.

*EBIT.* As discussed above, the increase in EBIT was driven primarily by an increase in residential developed lot sales and commercial project sales, the sale of the Washington, D.C. area land tracts and an increase in "legacy" land sales.

*Matters Impacting Future Crescent Results*

While Crescent regularly refreshes its property holdings, 2004 results reflected an opportunistic sale of property in the Washington, DC area which resulted in higher than normal gains during 2004. Crescent expects segment EBIT from continuing operations and discontinued operations to return to a more normal level of approximately $150 million in 2005. When property management or other significant accounting involvement is not retained by Crescent after the sale of an operating property, the transaction is recorded in discontinued operations.

*Year Ended December 31, 2003 as Compared to December 31, 2002*

*Operating Revenues.* The increase was driven primarily by increased revenues of $69 million from residential developed lot sales offset by a $5 million decrease in commercial rents. Residential developed lot sales increased in 2003 primarily due to sales at the Palmetto Bluff project in Bluffton, South Carolina of $51 million and increased sales in an existing project in Florida of $28 million. The decrease in commercial rents was due to a smaller portfolio of commercial properties in 2003 as a result of decreased development activities in the commercial sector.

*Operating Expenses.* The cost of residential developed lot sales increased $50 million as a result of increased sales as discussed above.

*Gains on Sales of Investments in Commercial and Multi-Family Real Estate.* The decrease was due to a $40 million decrease in legacy land sales offset by a $17 million increase in commercial land sales. The decrease in legacy land sales was due to a declining inventory of large, contiguous tracts in North and South Carolina, as well as a decrease in demand by large tract purchasers. The increase in commercial land sales was due to the initial sales of land at our Potomac Yard project in the Washington, DC area.

*EBIT.* The decrease was primarily the result of decreased land management sales partially offset by increased earnings from commercial land sales and residential developed lot sales.

**Other**

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | Variance 2004 vs 2003 | 2002 | Variance 2003 vs 2002 |
| | | | (in millions) | | |
| Operating revenues | $1,144 | $1,628 | $(484) | $ 303 | $1,325 |
| Operating expenses | 1,257 | 1,933 | (676) | 655 | 1,278 |
| Gains on sales of other assets, net | 4 | — | 4 | 32 | (32) |
| Operating income | (109) | (305) | 196 | (320) | 15 |
| Other income, net of expenses | 32 | 33 | (1) | (48) | 81 |
| EBIT | $ (77) | $ (272) | $ 195 | $(368) | $ 96 |

*Year Ended December 31, 2004 as Compared to December 31, 2003*

*Operating Revenues.* Operating revenues for 2004 decreased $484 million, compared to 2003. The decrease was driven primarily by a $337 million decrease in revenues related to decreased sales volumes as a result of the continued wind-down of DEM and a $162 million decrease due to the sale of Energy Delivery Services (EDS) in December 2003.

*Operating Expenses.* The decrease was driven primarily by:

- A $140 million decrease due primarily to a $51 million write-off in 2003 related to a corporate risk management information system that was abandoned, lower governance costs in 2004 due to cost reductions and allocation of certain costs previously designated as corporate to business units, and severance costs in 2003
- A $555 million decrease as a result of the continued wind-down of DEM and the sale of EDS in December 2003
- A $64 million decrease in 2004 as a result of the correction of an accounting error in prior periods related to reserves at Bison attributable to property losses at several Duke Energy subsidiaries
- A $21 million gain related to the settlement of the Enron bankruptcy proceedings in April 2004, and
- A $17 million decrease in general and administrative expense due to lower activity as a result of the decision in 2003 to exit the areas of refined products and NGLs at DEM. In addition, the absence of 2003 losses of $32 million from adverse market movements against some commodity positions positively affected the overall year over year increase.

*Gains on Sales of Other Assets, net.* Gains on sales of other assets for 2004 increased due primarily to a $13 million gain on the sale of DEM's 15% investment in Caribbean Nitrogen Company (an ammonia plant in Trinidad).

*EBIT.* EBIT increased in 2004 compared to 2003. The increase in EBIT was primarily driven by the wind-down of DEM, the reversal of insurance reserves at Bison, and other reductions in operating expense.

*Matters Impacting Future Other Results*

Other is expected to remain mostly comprised of certain unallocated corporate costs, DukeNet, D/FD, and Bison. DEM continues to wind-down its position in ammonia, coal, hydrocarbon and refined products. D/FD will continue to decrease its earnings as the partnership winds down by the end of 2005.

Duke Energy expects to deconsolidate its investment in DEFS subsequent to the closing of the transfer of its 19.7% interest to ConocoPhillips. During the first quarter of 2005 Duke Energy has discontinued hedge accounting for certain 2005 and 2006 contracts held by Duke Energy related to Field Services' commodity risk, which were previously accounted for as cash flow hedges. As a result of discontinuation of hedge accounting treatment, approximately $140 million of pretax deferred losses in AOCI related to these contracts have been reclassified into earnings by Duke Energy in the first quarter of 2005, which will impact Field Services' segment EBIT. On a prospective basis, these contracts will be accounted for under the MTM Model, which will impact Other EBIT. As a result of these contracts being accounted for under the MTM Model, future earnings for Other in 2005 and 2006 will be subject to increased volatility.

*Year Ended December 31, 2003 as Compared to December 31, 2002*

*Operating Revenues.* The increase was driven primarily by:

- A $1,300 million increase at DEM in connection with the January 1, 2003 adoption of the final consensus on EITF Issue No. 02-03. See earlier discussion under "Consolidated Operating Revenues"
- A $70 million increase in revenues at EDS, as a result of EDS beginning operations in May 2002 and thus not recognizing a full year of operations in the prior year. EDS was sold in December 2003, partially offset by
- A $172 million decrease due to the sale of Duke Engineering & Services, Inc. (DE&S) and DukeSolutions, Inc. (DukeSolutions) in 2002.

*Operating Expenses.* The increase was driven primarily by:

- A $1,300 million increase at DEM, due primarily to the adoption of the final consensus on EITF Issue No. 02-03
- A $72 million increase at EDS, as a result of EDS beginning operations in May 2002 and thus not recognizing a full year of operations in the prior year. EDS was sold in December 2003.
- A $51 million increase for a 2003 write-off related to a corporate risk management information system that was abandoned, partially offset by
- A $164 million decrease due to the sale of DE&S and DukeSolutions in 2002, and
- A $21 million decrease in DEM's general and administrative costs due to the wind-down of its business.

*Gains on Sales of Other Assets, net.* Gains on sales of other assets decreased in 2003 compared to 2002 due primarily to a 2002 net gain of $33 million on the sale of Duke Energy's remaining water operations.

*Other Income, net of expenses.* Other income, net of expenses increased in 2003, compared to 2002, due primarily to increased earnings related to D/FD.

*EBIT.* EBIT increased in 2003 compared to 2002. The increase in EBIT was primarily driven by the increase in other income, offset by the decrease due to the sale of assets.

**Other Impacts on Earnings Available for Common Stockholders**

Interest expense decreased $31 million in 2004 compared to 2003. The decrease was due primarily to:

- A $127 million decrease from net debt reduction and refinancing activities
- A $16 million write-off in 2003 as a result of an order by the PSCSC to write off regulatory assets related to debt issuance costs through interest expense, partially offset by
- $40 million of lower capitalized interest due to decreased construction activity
- $26 million of expenses related to financial instruments with characteristics of both liabilities and equity whose related distributions are now classified as interest expense instead of minority interest expense. Those instruments were classified as debt as of July 1, 2003, in accordance with SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"
- A $20 million increase associated with Canadian exchange rates, and
- $17 million higher interest costs in Brazil, due to Duke Energy's Brazilian debt being indexed annually to inflation and unfavorable impact of exchange rates.

Duke Energy anticipates interest expense to be approximately $1.1 billion in 2005. The projected reduction in interest expense from 2004 reflects the impact of Duke Energy's net debt reductions in 2004.

Interest expense increased $283 million in 2003 as compared to 2002. The increase was due primarily to:

- $136 million decrease in capitalized interest, resulting from lower plant construction activity in 2003

- $48 million of expenses related to certain financial instruments with characteristics of both liabilities and equity whose related distributions were classified as interest expense in 2003 instead of minority interest expense, and
- $99 million remaining increase was due primarily to higher debt balances, resulting mainly from debt assumed in, and issued with respect to, the acquisition of Westcoast, slightly offset by lower borrowing costs.

Minority interest expense increased $134 million in 2004 as compared to 2003, and decreased $55 million in 2003 as compared to 2002. Through June 30, 2003, minority interest expense included expense related to regular distributions on trust preferred securities of Duke Energy and its subsidiaries. As of July 1, 2003, those distributions were accounted for as interest expense on a prospective basis in accordance with the adoption of SFAS No. 150. As a result of this accounting change, minority interest expense decreased $55 million for 2004 and $75 million for 2003.

Minority interest expense as shown and discussed in the preceding business segment EBIT sections includes only minority interest expense related to EBIT of Duke Energy's joint ventures. It does not include minority interest expense related to interest and taxes of the joint ventures. Total minority interest expense related to the joint ventures (including the portion related to interest and taxes) increased $189 million in 2004 as compared to 2003, and increased $20 million in 2003 as compared to 2002. The 2004 change was driven by increased earnings at Field Services and improved results at DENA as a result of the continued wind-down of DETM. The 2003 change was driven by increased earnings at DEFS, and Natural Gas Transmission, offset by decreased earnings at DETM.

Income tax expense increased $1,247 million for the year ended December 31, 2004, compared to the same period in 2003, due primarily to the $3,482 million increase in earnings from continuing operations and the $45 million taxes recorded in 2004 on the repatriation of foreign earnings that is expected to occur in 2005 associated with the American Jobs Creation Act of 2004. These increases were partially offset by the $52 million reduction of state and federal income tax reserves and the $48 million of tax benefit from the change in state tax rates related to deferred taxes as a result of a reorganization of certain subsidiaries in 2004. Income tax expense decreased $1,318 million in 2003, compared to 2002, due primarily to the large impairment charges recorded in 2003. (See Note 6 to the Consolidated Financial Statements, "Income Taxes," for additional information.)

Income (loss) from discontinued operations was $258 million for 2004, ($158) million for 2003, and ($261) million for 2002. These amounts represent results of operations and gains (losses) on dispositions related primarily to International Energy's Asia-Pacific Business and European Business, Duke Capital Partners, LLC (DCP), Field Services, DENA, Crescent and DEM. (See Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale.")

The 2004 amount is primarily comprised of a $273 million after-tax gain resulting from the sale of International Energy's Asia-Pacific Business. The 2003 amount is primarily comprised of a $223 million after tax charge for International Energy's impairment charges incurred as a result of classifying its Asia-Pacific assets as held for sale and exiting the European market. The 2002 amount is primarily comprised of $194 million charge for the impairment of goodwill for International Energy's European Business.

During 2003, Duke Energy recorded a net-of-tax and minority interest cumulative effect adjustment for a change in accounting principles of $162 million, or $0.18 per basic share, as a reduction in earnings. The change in accounting principles included an after-tax and minority interest charge of $151 million, or $0.17 per basic share, related to the implementation of EITF and an after-tax charge of $11 million, or $0.01 per basic share, related to the implementation of SFAS No. 143, "Accounting for Asset Retirement Obligations."

In connection with the TEPPCO and DEFS transactions discussed above, Duke Energy has announced plans to periodically repurchase up to an aggregate $2.5 billion of common stock over the next three years.

### CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Duke Energy's operations change and accounting guidance evolves. Duke Energy has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information about Duke Energy's environment becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Duke Energy discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the audit committee, as appropriate. Duke Energy's critical accounting policies and estimates are listed below.

**Risk Management Accounting**

Duke Energy uses two comprehensive accounting models for its risk management activities in reporting its consolidated financial position and results of operations: the MTM Model and the Accrual Model. As further discussed in Note 1 to the Consolidated Financial Statements, the MTM Model is applied to trading and undesignated non-trading derivative contracts, and the Accrual Model is applied to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, as well as to non-derivative contracts used for commodity risk management purposes. For the three years ended December 31, 2004, the determination as to which model was appropriate was primarily based on accounting guidance issued by the Financial Accounting Standards Board (FASB) and the EITF. Effective January 1, 2003, Duke Energy adopted EITF Issue No. 02-03. While the implementation of such guidance changed the accounting model used for certain of Duke Energy's transactions, especially non-derivative energy trading contracts, the overall application of the models remained the same.

Under the MTM Model, an asset or liability is recognized at fair value on the Consolidated Balance Sheets and the change in the fair value of that asset or liability is recognized in the Consolidated Statements of Operations during the current period. While DENA is the primary business segment that uses this accounting model, the Franchised Electric, International Energy, and Field Services segments, as well as Other, also have certain transactions subject to this model. For the years ended December 31, 2004 and 2003, Duke Energy applied the MTM Model to its derivative contracts, unless subject to hedge accounting or the normal purchase and normal sale exemption (as described below). For the year ended December 31, 2002, Duke Energy also applied the MTM Model to energy trading contracts, as defined by EITF Issue No 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", which was superseded by EITF Issue No. 02-03.

The MTM Model is applied within the context of an overall valuation framework. All new and existing transactions are valued using approved valuation techniques and market data, and discounted using a London Interbank Offered Rate (LIBOR) based interest rate. When available, quoted market prices are used to measure a contract's fair value. However, market quotations for certain energy contracts may not be available for illiquid periods or locations. If no active trading market exists for a commodity or for a contract's duration, holders of these contracts must calculate fair value using internally developed valuation techniques or models. Key components used in these valuation techniques include price curves, volatility, correlation, interest rates and tenor. While volatility and correlation are the most subjective components, the price curve is generally the most significant component affecting the ultimate fair value for a contract subject to the MTM Model, especially after implementation of EITF Issue No. 02-03 due to the discontinuation of the MTM Model for certain energy trading contracts, such as transportation agreements. Prices for illiquid periods or locations are established by extrapolating prices for correlated products, locations or periods. These relationships are routinely re-evaluated based on available market data, and changes in price relationships are reflected in price curves prospectively. Consideration may also be given to the analysis of market fundamentals when developing illiquid prices. A deviation in any of the components affecting fair value may significantly affect overall fair value.

Valuation adjustments for performance and market risk, and administration costs are used to arrive at the fair value of the contract and the gain or loss ultimately recognized in the Consolidated Statements of Operations. While Duke Energy uses common industry practices to develop its valuation techniques, changes in Duke Energy's pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. However, due to the nature and number of variables involved in estimating fair values, and the interrelationships among these variables, sensitivity analysis of the changes in any individual variable is not considered to be relevant or meaningful.

Validation of a contract's calculated fair value is performed by an internal group independent of Duke Energy's trading areas. This group performs pricing model validation, back testing and stress testing of valuation techniques, prices and other variables. Validation of a contract's fair value may be done by comparison to actual market activity and negotiation of collateral requirements with third parties.

For certain derivative instruments Duke Energy applies either hedge accounting or the normal purchase and normal sales exemption in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The use of hedge accounting and the normal purchase and normal sales exemption provide effectively for the use of the Accrual Model. Under this model, there is generally no recognition in the Consolidated Statements of Operations for changes in the fair value of a contract until the service is provided or the associated delivery period occurs (settlement).

Hedge accounting treatment is used when Duke Energy contracts to buy or sell a commodity such as natural gas at a fixed price for future delivery corresponding with anticipated physical sales or purchase of natural gas (cash flow hedge). In addition, hedge accounting treatment is used when Duke Energy holds firm commitments or asset positions and enters into transactions that "hedge" the risk that the price of a commodity, such as natural gas or electricity, may change between the contract's inception and the physical delivery date of the commodity (fair value hedge). To the extent that the fair value of the hedge instrument offsets the transaction being hedged, there is no impact to the Consolidated Statements of Operations prior to settlement of the hedge. However, as not all of Duke Energy's hedges relate to the exact location being hedged, a certain degree of hedge ineffectiveness may be recognized in the Consolidated Statements of Operations.

The normal purchases and normal sales exemption, as provided in SFAS No. 133 as amended and interpreted by Derivative Implementation Group (DIG) Issue C15, "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity," and amended by SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," indicates that no recognition of the contract's fair value in the Consolidated Financial Statements is required until settlement of the contract (in Duke Energy's case, the delivery of power). Previously, Duke Energy applied this exemption for certain contracts involving the sale of power in future periods. SFAS No. 149 includes certain modifications and changes to the applicability of the normal purchase and normal sales scope exception for contracts to deliver electricity. As a result, Duke Energy reevaluated its policy for accounting for forward power sale contracts and determined that substantially all forward contracts to sell power entered into after July 1, 2003 will be designated as cash flow hedges. To the extent that the hedge is perfectly effective, income statement recognition for the contract will be the same under either model.

In addition to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, the Accrual Model also encompasses non-derivative contracts used for commodity risk management purposes. For these non-derivative contracts, there is no recognition in the Consolidated Statements of Operations until the service is provided or delivery occurs.

For additional information regarding risk management activities, see Quantitative and Qualitative Disclosures about Market Risk. The Quantitative and Qualitative Disclosures about Market Risk include daily earnings at risk information related to commodity derivatives recorded using the MTM Model and an operating income sensitivity analysis related to hypothetical changes in certain commodity prices recorded using the Accrual Model.

**Regulatory Accounting**

Duke Energy accounts for certain of its regulated operations (primarily Franchised Electric and Natural Gas Transmission) under the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." As a result, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes, recent rate orders to other regulated entities, and the status of any pending or potential deregulation legislation. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery. This assessment reflects the current political and regulatory climate at the state, provincial and federal levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs would be required to be recognized in operating income. Total regulatory assets were $2,108 million as of December 31, 2004 and $2,016 million as of December 31, 2003. Total regulatory liabilities were $1,744 million as of December 31, 2004 and $1,788 million as of December 31, 2003. (See Note 4 to the Consolidated Financial Statements, "Regulatory Matters.")

**Long-Lived Asset Impairments and Assets Held For Sale**

Duke Energy evaluates the carrying value of long-lived assets, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. For long-lived assets, an impairment would exist when the carrying value exceeds the sum of estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, the asset's carrying value is adjusted to its estimated fair value. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used for developing estimates of future cash flows.

Duke Energy uses the best information available to estimate fair value of its long-lived assets and may use more than one source. Judgment is exercised to estimate the future cash flows, the useful lives of long-lived assets and to determine management's intent to use the assets. The sum of undiscounted cash flows is primarily dependent on forecasted commodity prices for sales of power, natural gas or NGL, costs of fuel over periods of time consistent with the useful lives of the assets or changes in the real estate market. Management's intent to use or dispose of assets is subject to re-evaluation and can change over time.

A change in Duke Energy's plans regarding, or probability assessments of, holding or selling an asset could have a significant impact on the estimated future cash flows. Duke Energy considers various factors when determining if impairment tests are warranted, including but not limited to:

- Significant adverse changes in legal factors or in the business climate;

- A current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- Significant adverse changes in the extent or manner in which an asset is used or in its physical condition or a change in business strategy;
- A significant change in the market value of an asset; and
- A current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

Judgment is also involved in determining the timing of meeting the criteria for classification as an asset held for sale under SFAS No. 144.

During 2004, Duke Energy recorded impairments on several of its long-lived assets. (For additional discussion of these impairments, see Note 12 to the Consolidated Financial Statements, "Impairment and Other Related Charges.")

Duke Energy may dispose of certain other assets in addition to the assets classified as held for sale at December 31, 2004. Accordingly, based in part on current market conditions in the merchant energy industry, it is reasonably possible that Duke Energy's current estimate of fair value of its long-lived assets being considered for sale at December 31, 2004 and its other long-lived assets, could change and that change may impact the consolidated results of operations. In addition, Duke Energy could decide to dispose of additional assets in future periods, at prices that could be less than the book value of the assets.

**Impairment of Goodwill**

Duke Energy evaluates the impairment of goodwill under SFAS No. 142, "Goodwill and Other Intangible Assets." The majority of Duke Energy's goodwill at December 31, 2004 relates to the acquisition of Westcoast in March 2002. The remainder relates to Field Services, International Energy's Latin American operations and Crescent. As required by SFAS No. 142, Duke Energy performs an annual goodwill impairment test and updates the test if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Key assumptions used in the analysis include, but are not limited to, the use of an appropriate discount rate, estimated future cash flows and estimated run rates of general and administrative costs. In estimating cash flows, Duke Energy incorporates current market information as well as historical factors and fundamental analysis as well as other factors into its forecasted commodity prices. As a result of the 2004 impairment test required by SFAS No. 142, Duke Energy did not record any impairment on its goodwill. In the third quarter of 2003, Duke Energy recorded a $254 million goodwill impairment charge to write off all of DENA's goodwill, most of which related to certain aspects of DENA's trading and marketing business. This impairment charge reflected the reduction in scope and scale of DETM's business and the continued deterioration of market conditions affecting DENA during 2003. In 2002, Duke Energy recorded a goodwill impairment charge of $194 million related to International Energy's European Business, which was sold in 2003. Duke Energy used a discounted cash flow analysis utilizing the key assumptions described above to perform the analysis.

Management continues to remain alert for any indicators that the fair value of a reporting unit could be below book value and will assess goodwill for impairment as appropriate.

As of the acquisition date, Duke Energy allocates goodwill to a reporting unit. Duke Energy defines a reporting unit as an operating segment or one level below.

**Revenue Recognition**

*Unbilled and Estimated Revenues.* Revenues on sales of electricity, primarily at Franchised Electric, are recognized when the service is provided. Unbilled revenues are estimated by applying an average revenue/kilowatt hour for all customer classes to the number of estimated kilowatt hours delivered but not billed. Differences between actuals and estimates are immaterial and are a result of customer mix.

Revenues on sales of natural gas, natural gas transportation, storage and distribution as well as sales of petroleum products, primarily at Natural Gas Transmission and Field Services, are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. These estimates are generally based on contract data, regulatory information, estimated distribution usage based on historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month.

*Trading and Marketing Revenues.* The recognition of income in the Consolidated Statements of Operations for derivative activity is primarily dependent on whether the Accrual Model or MTM Model is applied. Prior to January 1, 2003, Duke Energy applied the MTM Model to certain derivative contracts and certain contracts classified as energy trading pursuant to EITF Issue 98-10. With the implementation of EITF Issue 02-03, use of the MTM Model has been restricted to contracts classified as derivatives pursuant to SFAS No. 133. Contracts classified previously as energy trading that do not meet the definition of a derivative are subject to the Accrual Model. While the MTM Model is the default method of accounting for all SFAS No. 133 derivatives, SFAS No. 133 allows for the use of the Accrual Model for derivatives designated as hedges and certain scope exceptions, including the normal purchase and normal sale exception. Duke Energy designates a derivative as a hedge or a normal purchase or normal sale contract in accordance with internal hedge guidelines and the requirements provided by SFAS No. 133. (For further information regarding the Accrual Model or MTM Model, see Risk Management Accounting above. For further information regarding the presentation of gains and losses or revenue and expense in the Consolidated Statements of Operations, see Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies".)

**Pension and Other Post-Retirement Benefits**

Duke Energy and its subsidiaries maintain a non-contributory defined benefit retirement plan. It covers most U.S. employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits. Duke Energy and most of its subsidiaries also provide some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

Westcoast and its subsidiaries maintain contributory and non-contributory defined benefit (DB) and defined contribution (DC) retirement plans covering substantially all employees. The DB plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC plans, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. Westcoast also provides health care and life insurance benefits for retired employees on a non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. Effective December 31, 2003, a new plan was implemented for all non bargaining employees and the majority of bargaining employees. The new plan will apply to employees retiring on and after January 1, 2006. The new plan is predominantly a defined contribution plan as compared to the existing defined benefit program.

Duke Energy accounts for its defined benefit pension plans using SFAS No. 87, "Employers' Accounting for Pensions." Under SFAS No. 87, pension income/expense is recognized on an accrual basis over employees' approximate service periods. Other post-retirement benefits are accounted for using SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." (See Note 21 to the Consolidated Financial Statements, "Employee Benefit Plan".)

Funding requirements for defined benefit plans are determined by government regulations, not SFAS No. 87. Duke Energy made voluntary contributions of $250 million in 2004 and $181 million in 2003 to its U.S. defined benefit retirement plan. No contributions to the Duke Energy plan were necessary in 2002. No contributions are expected for the U.S. plan in 2005. Duke Energy made contributions to the Westcoast DB plans of approximately $28 million in 2004, $11 million in 2003 and $9 million in 2002. Duke Energy anticipates that it will make contributions of approximately $33 million to the Westcoast DB plans in 2005. Duke Energy made contributions to the Westcoast DC plans of approximately $3 million in 2004, $3 million in 2003 and $2 million in 2002. Duke Energy anticipates that it will make contributions of approximately $3 million to the Westcoast DC plans in 2005.

The calculation of pension expense, other post-retirement expense and Duke Energy's pension and other post-retirement liabilities require the use of assumptions. Changes in these assumptions can result in different expense and reported liability amounts, and future actual experience can differ from the assumptions. Duke Energy believes that the most critical assumptions for pension and other post-retirement benefits are the expected long-term rate of return on plan assets and the assumed discount rate. Additionally, the health care trend rate assumption is critical for other post-retirement benefits.

Duke Energy recognized pre-tax pension income of $1 million and pre-tax other post-retirement benefits expense of $58 million in 2004. Westcoast recognized pre-tax pension expense of $14 million and pre-tax other post-retirement benefits expense of $8 million in 2004. In 2005, Duke Energy's U.S. pension expense is expected to be approximately $23 million due to lower than expected asset returns from 2000 through 2002 being amortized into expense over a five year period elected as allowed under SFAS No. 87. Duke Energy's other U.S. and Westcoast plans do not expect material changes from the expense of 2004.

For both pension and other post-retirement plans, Duke Energy assumed that its U.S. plan's assets would generate a long-term rate of return of 8.5% as of September 30, 2004. The assets for Duke Energy's U.S. pension and other post retirement plans are maintained by a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation target was set after considering the investment objective and the risk profile with respect to the trust. U.S. equities are held for their high expected return. Non-U.S. equities, debt securities, and real estate are held for diversification. Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments. Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to its targeted allocation when considered appropriate.

The expected long-term rate of return of 8.5% for the Duke Energy U.S. assets was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers. The weighted average returns expected by asset classes were 4.2% for U.S. equities, 1.9% for Non U.S. equities, 2.2% for fixed income securities, and 0.2% for real estate. A premium of 0.4% was added for the higher returns expected for the plan's use of active asset managers.

If Duke Energy had used a long-term rate of 8.0% in 2004, pre-tax pension expense would have been approximately $14 million. If Duke Energy had used a long-term rate of 9.0% pre-tax pension income would have been higher by approximately $14 million. If Duke Energy had used a long-term rate of 8.0% in 2004, pre-tax other post-retirement expense would have been higher by approximately $1 million. If Duke Energy had used a long-term rate of 9.0% pre-tax other post retirement expense would have been lower by approximately $1 million.

The expected long-term rate of return for the Westcoast plans assets was 7.50% as of September 30, 2004. The Westcoast plans assets for registered pension plans are maintained by a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation target was set after considering the investment objective and the risk profile with respect to the trust. Canadian equities are held for their high expected return. Non-Canadian equities are held for their high expected return as well as diversification relative to Canadian equities and debt securities. Debt securities are also held for diversification.

The expected long-term rate of return of 7.50% for the Westcoast assets was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers. The weighted average returns expected by asset classes were 2.0% for Canadian equities, 1.9% for U.S. equities, 1.9% for Europe, Australasia and Far East equities, and 1.7% for fixed income securities. If the Westcoast plan had used a long-term rate of 7.0% in 2004, pre-tax pension expense would have been higher by $2 million. If the Westcoast plans had used a long-term rate of 8.0% in 2004, pre-tax pension expense would have been lower by $2 million. The Westcoast other post-retirement plan does not hold any assets.

Duke Energy discounted its future U.S. pension and other post-retirement obligations using a rate of 6.00% as of September 30, 2004 and 2003, compared to 6.75% as of September 30, 2002. Duke Energy determines the appropriate discount based on the current rates earned on long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan. For 2004, the discount rate used to calculate pension and other post-retirement expense was 6.00%. Lowering the discount rate by 0.25% (from 6.00% to 5.75%) would have increased Duke Energy's 2004 pre-tax pension income by approximately $3 million. Increasing the discount rate by 0.25% (from 6.00% to 6.25%) would have increased Duke Energy's 2004 pre-tax pension expense by approximately $3 million. Lowering the discount rate by 0.25% (from 6.00% to 5.75%) would have increased Duke Energy's 2004 pre-tax other post retirement expense by approximately $1 million. Increasing the discount rate by 0.25% (from 6.00% to 6.25%) would have decreased Duke Energy's 2004 pre-tax other post retirement expense by approximately $1 million.

Westcoast discounted its future pension and other post-retirement obligations using a rate of 6.25% as of September 30, 2004 compared to 6.00% as of September 30, 2003 and 6.50% as of September 30, 2002. For Westcoast the discount rate used to determine the pension and other post-retirement obligations is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan. For 2004, the discount rate used to calculate pension expense was 6.00%. Lowering the discount rate by 0.25% (from 6.00% to 5.75%) would have increased Duke Energy's 2004 pre-tax pension expense by approximately $2 million. Increasing the discount rate by 0.25 % (from 6.00% to 6.25%) would have decreased Duke Energy's 2004 pre-tax pension expense by approximately $2 million. Lowering the discount rate by 0.25% (from 6.00% to 5.75%) would have increased Duke Energy's 2004 pre-tax other post-retirement expense by less than $1 million. Increasing the discount rate by 0.25 % (from 6.00% to 6.25%) would have decreased Duke Energy's 2004 pre-tax other post-retirement expense by less than $1 million.

Duke Energy's U.S. post-retirement plan uses a health care trend rate which reflects the near and long-term expectation of increases in medical costs. As of September 30, 2004, the health care trend rates were 9.50%, which grades to 6.00% by 2009 for employees who are not eligible for Medicare and 12.5%, which grades to 6.00% by 2012 for employees who are eligible for Medicare. If Duke Energy had used a health care trend rate one percentage point higher, pre-tax other post-retirement expense would have been higher by $3 million. If Duke Energy had used a health care trend rate one percentage point lower, pre-tax other post-retirement expense would have been lower by $3 million.

The Westcoast post-retirement plans use a health care trend rate which reflects the near and long-term expectation of increases in medical costs. As of September 30, 2004, the health care trend rates were 9.00%, which grades to 5.00% by 2008. If Duke Energy had used a health care trend rate one percentage point higher, pre-tax other post-retirement expense would have been higher by $1 million. If Duke Energy had used a health care trend rate one percentage point lower, pre-tax other post-retirement expense would have been lower by less than $1 million.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in Duke Energy's pension and post-retirement plans will impact Duke Energy's future pension expense and liabilities. Management cannot predict with certainty what these factors will be in the future.

## LIQUIDITY AND CAPITAL RESOURCES

### Known Trends and Uncertainties

Duke Energy will rely primarily upon cash flows from operations and borrowings to fund its liquidity and capital requirements for 2005. Also, Duke Energy expects cash flows from asset sales related to Duke Energy transferring a 19.7% interest in DEFS to ConocoPhillips as well as the sale by Field Services of TEPPCO and Duke Energy's sale of its limited partner interests in TEPPCO Partners L.P., as discussed below. The net cash from these transactions along with current cash, cash equivalents and short-term investment balances of approximately $1.9 billion and future cash generated from operations may be utilized by Duke Energy to periodically repurchase up to an aggregate of $2.5 billion of common stock over the next three years. A material adverse change in operations or available financing may impact Duke Energy's ability to fund its current liquidity and capital resource requirements. The relatively stable operating cash flows of the Franchised Electric and Natural Gas Transmission businesses currently compose a substantial portion of Duke Energy's cash flow from operations and it is anticipated that they will continue to do so for the next several years.

Duke Energy currently anticipates net cash provided by operating activities in 2005 to be approximately $2.7 billion, including approximately $300 million of residential real estate capital expenditures. Net cash provided by operating activities in 2005 assumes a mid-year closing of the sale of 19.7% of Duke Energy's interest in DEFS to ConocoPhillips, resulting in a change to equity method accounting treatment for Duke Energy's remaining ownership interest in DEFS as any future cash distributions from DEFS to Duke Energy, subsequent to the closing of the sale transaction, will be included in operating activities in the Consolidated Statements of Cash Flows. Anticipated cash provided by operating activities for 2005 includes the impact of realizing approximately $450 million of net operating losses, which resulted principally from the carryover of unutilized 2004 income tax losses from the sale of DENA's Southeast Plants and the partially completed Moapa and Luna plants in 2004. Achievement of these projected amounts is subject to a number of factors, including, but not limited to, regulatory constraints, economic trends, and market volatility.

Duke Energy projects 2005 capital and investment expenditures of approximately $2.5 billion, including approximately $300 million of residential real estate capital expenditures. Duke Energy continues to focus on reducing risk and restructuring its business for future success and will invest principally in its strongest business sectors with an overall focus on positive net cash generation. Based on this goal, approximately 70% of total projected 2005 capital expenditures are projected to be allocated to Natural Gas Transmission and Franchised Electric. Total projected capital and investment expenditures include approximately $1.4 billion for maintenance and upgrades of existing plants, pipelines, and infrastructure to serve load growth. Additionally, Duke Energy anticipates approximately $470 million in capital and investment expenditures for Crescent, including $300 million of residential real estate capital expenditures. Expenditures at Crescent and Natural Gas Transmission constitute the majority of the expansion capital planned in 2005 by Duke Energy. Duke Energy is also focused on pursuing various options to create a sustainable business model at DENA, including consideration of potential business partners. See earlier discussion in Introduction section for more information.

In February 2005, DEFS sold its wholly-owned subsidiary TEPPCO for approximately $1.1 billion and Duke Energy sold its limited partner interest in TEPPCO Partners, L.P. for approximately $100 million, in each case to EPCO, an unrelated third party. These transactions closed in the first quarter of 2005 and are estimated to result in a pretax gain to Duke Energy of approximately $900 million (net of approximately $330 million of minority interest).

Additionally, in February 2005, Duke Energy executed an agreement with ConocoPhillips whereby Duke Energy has agreed to transfer a 19.7% interest in DEFS to ConocoPhillips for direct and indirect monetary and non-monetary consideration of approximately $1.1 billion. The consideration is expected to consist of the current Canadian operations of DEFS, the transfer of certain Canadian assets from ConocoPhillips to Duke Energy and the transfer of certain U.S. Midstream assets, or cash, from ConocoPhillips to DEFS, and the payment of cash from ConocoPhillips to Duke Energy of at least $500 million. Upon completion of this transaction, DEFS will be owned 50% by Duke Energy and 50% by ConocoPhillips. As a result, Duke Energy expects to account for its investment in DEFS using the equity method subsequent to closing of the transaction. This transaction, which is subject to customary U.S. and Canadian regulatory approvals, is expected to close in the latter half of 2005.

As a result of the transactions discussed above, Duke Energy anticipates its debt to total capitalization ratio to be below 50% by the end of 2005.

In 2005, Duke Energy expects to continue to reduce debt principally through the payment of contractual debt maturities and to begin a stock repurchase program. The amount of debt reduction and repurchase of common stock is subject to certain factors including the use of existing cash, cash equivalents and short-term investments of $1.9 billion at December 31, 2004, the receipt of cash proceeds from the TEPPCO sale and DEFS restructuring and other market-driven investment opportunities.

Duke Energy monitors compliance with all debt covenants and restrictions, and does not currently believe that it will be in violation or breach of its debt covenants. However, circumstances could arise that may alter that view. If and when management had a belief that such potential breach could exist, appropriate action would be taken to mitigate any such issue. Duke Energy also maintains an active dialogue with the credit rating agencies, and believes that the current credit ratings have stabilized. However, in February 2005, Moody's Investor Service (Moody's) changed the outlook for Duke Capital and DEFS to Negative, as a result of Duke Energy agreeing to transfer a 19.7% interest in DEFS to ConocoPhillips, Field Services' selling TEPPCO, Duke Energy selling its limited partner interests in TEPPCO Partners, L.P. and the $2.5 billion stock repurchase announcement. In addition, Moody's placed the credit ratings of Maritimes & Northeast Pipeline LLC and Maritimes & Northeast Pipeline LP under Review for Possible Downgrade in February 2005, due to concerns over downward revisions in gas reserve estimates for the Sable Offshore Energy Projects.

**Operating Cash Flows**

Net cash provided by operating activities was $4,139 million in 2004 compared to $3,396 million in 2003, an increase of $743 million. The increase in cash provided by operating activities was due primarily to higher cash settlements from trading and hedging activities, increased cash earnings related to Field Services, and increased cash flows in 2004 from changes in working capital related primarily to a cash refund received related to income taxes, which were partially offset by $86 million of increased pension plan contributions in 2004. Duke Energy made a voluntary contribution of $250 million to its U.S. defined benefit pension plan (U.S. plan) and a $28 million voluntary contribution to its Westcoast retirement plans (Westcoast plans in 2004). Duke Energy anticipates it will make no contributions to the U.S. plan and $33 million of contributions to the Westcoast plans in 2005.

Net cash provided by operating activities was $3,396 million in 2003 compared to $4,199 million in 2002, a decrease of $803 million. The decrease in cash provided by operating activities was due primarily to lower cash settlements from trading and hedging activities, and less cash flow in 2003 from changes in working capital, principally accounts payable and accounts receivable. Additionally, in 2003, Duke Energy made a voluntary contribution of $181 million to its U.S. plan; no contributions were made in 2002. Duke Energy also made contributions to the Westcoast plans of approximately $11 million in 2003 and $9 million in 2002.

In June 2002, the state of North Carolina passed new clean-air legislation that freezes electric utility rates from June 20, 2002, the effective date of the statute, to December 31, 2007 (rate-freeze period), subject to certain conditions, in order for certain North Carolina electric utilities, including Duke Energy, to make significant reductions in emissions of sulfur dioxide and nitrogen oxides from the state's coal-fired power plants. The legislation permits Duke Energy the flexibility to vary the amortization schedule for expensing compliance costs. During the rate-freeze period, Duke Energy is expected to recover a minimum of 70% of the total estimated costs of compliance. As part of this legislation Duke Energy will spend an estimated total of $1.5 billion over the entire program, ending in 2011, to install pollution controls in its coal-fired plants. Cash outflows associated with this legislation were approximately $107 million in 2004. (See Note 4 to the Consolidated Financial Statements, "Regulatory Matters".) Duke Energy anticipates cash outflows associated with this legislation to be approximately $285 million in 2005. As these cash outflows are funded by operating revenues from regulated electric customers, they are operating cash outflows, not capital and investment expenditures.

### Investing Cash Flows

Cash used in investing activities was $764 million in 2004 compared to $668 million in 2003, an increase of $96 million. Cash used in investing activities was $668 million in 2003 compared to $6,954 million in 2002, a decrease of $6,286 million. The primary use of cash related to investing activities is capital and investment expenditures, detailed by business segment in the following table.

**Capital and Investment Expenditures by Business Segment (a)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | | (in millions) | |
| Franchised Electric | $1,020 | $ 997 | $1,269 |
| Natural Gas Transmission | 533 | 766 | 2,878 |
| Field Services | 213 | 211 | 309 |
| DENA | 22 | 277 | 2,013 |
| International Energy | 28 | 71 | 412 |
| Crescent[b] | 568 | 290 | 275 |
| Other[c] | 39 | (21) | 136 |
| Cash acquired in acquisitions | — | — | (77) |
| Total consolidated | $2,423 | $2,591 | $7,215 |

(a) Amounts include the acquisition of Westcoast in 2002
(b) Amounts include capital expenditures for residential real estate included in operating cash flows of $322 million in 2004, $196 million in 2003 and $179 million in 2002
(c) Amounts include deferral of the consolidation of 50% of the profit earned by D/FD for the construction of DENA's merchant generation plants, which is associated with Duke Energy's share of ownership

Capital and investment expenditures, including Crescent's residential real estate investments, decreased $168 million in 2004 compared to 2003. The decrease was due primarily to decreased investments in generating facilities at DENA due to the continuing downturn in the merchant energy portion of its business that began in 2002, and decreased investments at Gas Transmission due to the completion of infrastructure projects in western Canada and New England in 2003.

The increase in cash used in 2004 when compared to 2003 was also impacted by a $292 million increase in proceeds from the sales of commercial and multi-family real estate at Crescent, due primarily to sales of the Potomac Yard retail center and the Alexandria land tract in 2004.

These decreases in cash used were partially offset by a $424 million decrease in net proceeds received from the sales of equity investments and other assets, primarily related to sales in 2003 of DENA's 50% ownership interest in Ref-Fuel; Natural Gas Transmission's sale of its wholly owned Empire State Pipeline and its investments in the Alliance Pipeline and Vector Pipeline, LP (Vector); Field Services' sale of certain gathering pipelines and gas processing plants; Duke Energy's sale of its TEPPCO Class B units; DEM's sale of DE Hydrocarbons, LLC and the monetization of various investments at DCP. These were partially offset by the sale of International Energy's Asia-Pacific Business and DENA's sale of its Southeast Plants and its Moapa and Luna partially completed facilities, and its Vermillion facilities, in 2004.

Capital and investment expenditures, including Crescent residential real estate investments, decreased $4,624 million in 2003 compared to 2002. The decrease was due primarily to the 2002 acquisition of Westcoast for $1,707 million, net of cash acquired, and lower investments in generating facilities at DENA, resulting from the downturn in the merchant energy portion of its business, the most significant of which were: a $621 million decrease due to 2002 expenditures on the Moapa, Grays Harbor, and Luna partially completed facilities; a $380 million decrease in expenditures for the Marshall, Sandersville, and Moss Landing facilities; and a $434 million decrease in turbine purchases. Capital and investment expenditures also decreased in 2003 due to lower plant construction costs at Franchised Electric, primarily due to an approximate $250 million decrease in expenditures related to environmental equipment at its coal-fired plants and the Mill Creek combustion turbine plant, which was completed in 2003; a $268 million decrease in plant construction costs at International Energy, primarily in Australia; a $226 million decrease in investments in Natural Gas Transmission's 50% interest in Gulfstream; and a reduction in Other investments, primarily related to DCP.

The decrease in cash used in investing activities in 2003 when compared to 2002 was also impacted by an increase in proceeds from the sale of equity investments and other assets, and sales of and collections on notes receivable of $1,450 million. The increased proceeds were primarily due to the sale of DENA's 50% ownership interest in Ref-Fuel; Natural Gas Transmission's sale of its wholly owned Empire State Pipeline, sale of its investment in the Alliance Pipeline and the associated Aux Sable liquids plant, Foothills Pipe Lines, Ltd, and Vector; Field Services' sale of certain gathering pipelines and gas processing plants, Duke Energy's sale of its TEPPCO Partners, L.P. Class B units; DEM's sale of DE Hydrocarbons LLC; International Energy's sale of its 85.7% majority interest in P.T. Puncakjaya Power and its European Business; and the monetization of various investments at DCP.

**Financing Cash Flows and Liquidity**

Duke Energy's consolidated capital structure as of December 31, 2004, including short-term debt, was 51% debt, 45% common equity and 4% minority interests. As a result of Duke Energy transferring a 19.7% interest in DEFS to ConocoPhillips, Field Services selling TEPPCO, Duke Energy selling its limited partner interest in TEPPCO Partners, L.P. and the announced $2.5 billion stock repurchase program, Duke Energy anticipates its debt to total capitalization ratio to be below 50% by the end of 2005. The fixed charges coverage ratio, calculated using Securities and Exchange Commission (SEC) guidelines, was 2.3 times for 2004 and 2.2 times for 2002. Earnings were inadequate to cover fixed charges by $1,707 million for the year ended December 31, 2003 as a result of approximately $3.5 billion in non-cash impairment charges incurred in 2003.

Net cash used in financing activities increased $621 million for the year ended December 31, 2004, compared to 2003. This change was due primarily to approximately $1.9 billion of higher net paydowns of long-term debt, commercial paper and notes payable in 2004 as compared to 2003, offset by approximately $1.4 billion of higher proceeds from common stock issuances during 2004, driven by the settlement of the forward purchase contract component of Duke Energy's Equity Units in May and November 2004. Total debt reductions of approximately $4.6 billion in 2004 consisted of $3.9 billion in cash redemptions (see Note 15 to the Consolidated Financial Statements, "Debt and Credit Facilities") and approximately $840 million of debt retired (as a non-cash financing activity) as part of the sale of International Energy's Asia-Pacific Business, which were partially offset by minimal issuances of long-term debt. The $840 million does not include the approximately $50 million of Asia-Pacific debt which was placed in trust and fully funded in connection with the closing of the sale transaction and repaid in September 2004. The assets held in the consolidated trust were received from Alinta, Ltd. as part of the sale of the Asia-Pacific Business.

From 2002 to 2003 cash flows from financing activities decreased $5,503 million to net cash used in financing activities of $2,657 in 2003 from net cash provided by financing activities of $2,846 million in 2002. This change was due primarily to the net reduction of outstanding long-term debt, trust preferred securities, and notes payable and commercial paper during 2003 as compared to the same period in 2002 when Duke Energy acquired Westcoast and financed other business expansion projects. The change was also due to a reduction in the issuance of common stock in 2003 compared to 2002, when Duke Energy issued 54.5 million shares of common stock in a public offering, the proceeds of which were used to repay commercial paper that had been issued to fund a portion of the consideration for the Westcoast acquisition. This change in cash flows from financing activities was aligned with Duke Energy's strategy to reduce outstanding debt and strengthen the balance sheet.

During 2004, cash from operations, the sale of non-strategic assets and the settlement of the forward stock purchase components of Duke Energy's Equity Units in May and November 2004, were more than adequate for funding capital expenditures, dividend payments and planned debt reductions.

With cash, cash equivalents and short-term investments on hand at December 31, 2004 of $1.9 billion and a more stable business environment, Duke Energy has financial flexibility to buy back common stock, invest incrementally or pay down additional debt. Duke Energy is evaluating these options and will determine the best economic decision to meet the needs of shareholders and the long-term financial strength of Duke Energy. In connection with the TEPPCO and DEFS transactions discussed above, Duke Energy has announced plans to periodically repurchase up to an aggregate $2.5 billion of common stock over the next three years.

*Significant Financing Activities.* In February 2004, Duke Capital remarketed $875 million of senior notes due in 2006, underlying its 8.25% Equity Units and reset the interest rate from 5.87% to 4.302%. As this action was contemplated in the original Equity Units issuance, the transaction had no immediate accounting implications. Subsequently, Duke Capital exchanged $475 million of the remarketed senior notes for $200 million of 4.37% senior unsecured notes due in 2009 and $288 million of 5.5% senior unsecured notes due in 2014. In accordance with EITF Issue No. 96-19, "Debtors Accounting for a Modification or Exchange of Debt Instruments," the $475 million of remarketed senior notes issued earlier at 4.302% was extinguished. This exchange transaction resulted in an approximate $11 million loss, which was included in Interest Expense in the Consolidated Statements of Operations for the year ended December 31, 2004. Proceeds from the remarketed notes were used to purchase U.S. Treasury securities that were held by the collateral agent and, upon maturity, were used to satisfy the forward stock purchase contract component of the 8.25% Equity Units in May 2004.

In March 2004, Duke Energy redeemed the entire issue of its 7.20% debt due to an affiliate in 2037 for approximately $350 million, in connection with the redemption of its Duke Energy Capital Trust I 7.20% Cumulative Quarterly Income Preferred Securities due in 2037.

As the securities were redeemed at par, security holders received $25 per each note held, plus accrued and unpaid distributions to the redemption date.

In April 2004, approximately $840 million of debt was retired (as a non-cash financing activity) as part of the sale of the Asia-Pacific operations. In September 2004, Duke Energy repaid approximately $50 million of Asia-Pacific debt from assets that were held in a consolidated trust for the specific purpose of retiring the debt. The assets held in the consolidated trust were received from Alinta, Ltd. as part of the sale of the Asia-Pacific Business. Duke Energy completed the sale of the Asia-Pacific assets, which includes substantially all of Duke Energy's assets in Australia and New Zealand, to Alinta Ltd. on April 23, 2004.

In May 2004, Duke Energy issued 22,449,000 shares of its common stock in the settlement of the forward-purchase contract component of its Equity Units issued in March 2001. Under the terms of the contract, the Equity Unit holders were required to purchase common stock at a settlement rate based on the current market price of Duke Energy's common stock at the time of settlement with a floor and a ceiling. The rate was 0.6414 shares of stock per Equity Unit. Duke Energy received $875 million in proceeds as a result of the settlement, which was included in issuances of common stock and common stock related to employee benefit plans on the Consolidated Statement of Cash Flows.

Also in May 2004, Duke Energy redeemed its Series C 6.60% senior notes due in 2038, at a $200 million face value. As the securities were redeemed at par, security holders received $25 per each note held, plus accrued interest to the redemption date.

In June 2004, Duke Energy redeemed the entire issue of its 7.20% debt due to an affiliate in 2039 for approximately $250 million, in connection with the redemption of its Duke Energy Capital Trust II 7.20% Trust Preferred Securities. As the securities were redeemed at par, security holders received $25 per preferred security held, plus accrued and unpaid distributions to the redemption date.

In August 2004, Duke Energy redeemed the entire issue of its 8⅜% debt due to an affiliate in 2029 for $250 million, in connection with the redemption of its Duke Capital Financing Trust III 8⅜% Trust Preferred Securities. As the securities were redeemed at par, security holders received $25 per preferred security held, plus accrued and unpaid distributions to the redemption date.

Additionally, Duke Capital remarketed $750 million of its 4.32% senior notes due in 2006, underlying Duke Energy's 8.00% Equity Units on August 11, 2004. As a result of the remarketing, the interest rate on the notes was reset to 4.331%, effective August 16, 2004. Duke Capital subsequently exchanged $400 million of the 4.331% notes for $408 million of 5.668% notes due in 2014. This transaction resulted in an approximate $6 million loss, which was included in Interest Expense in the Consolidated Statements of Operations for the year end December 31, 2004. Proceeds from the remarketed notes were used to purchase U.S. Treasury securities held by the collateral agent and, upon maturity, were used to satisfy the forward stock purchase contract component of the 8% Equity Units in November 2004.

In October 2004, Duke Energy prepaid a portion of a $994 million floating rate facility at DENA. The payment consisted of $565 million, an associated $35 million working capital facility and accrued interest on the facilities. Additionally, in December 2004, Duke Energy repaid the remaining outstanding balance of $429 million.

In November 2004, Duke Energy issued 18,693,000 shares of its common stock in the settlement of the forward-purchase contract component of its Equity Units issued in November 2001. Under the terms of the contract, the Equity Unit holders were required to purchase stock at the time of settlement rate based on the current market price of Duke Energy's common stock at the time of the settlement with a floor and a ceiling. The rate was 0.6231 shares of stock per Equity Unit. Duke Energy received $750 million in proceeds as a result of the settlement, which was included in issuances of common stock and common stock related to employee benefit plans on the Consolidated Statement of Cash Flows.

During 2004, Duke Capital purchased $202 million of its outstanding notes in the open market. These purchases included $140 million of Duke Capital 5.50% senior notes due March 1, 2014, $52 million of Duke Capital 4.37% senior notes due March 1, 2009, and $10 million of Duke Capital 6.75% senior notes due February 15, 2032. These securities were purchased at the then-current market price plus accrued interest.

*Preferred and Preference Stock of Duke Energy's Subsidiaries.* In June 2004, Westcoast redeemed all remaining outstanding Cumulative Redeemable First Preferred Shares, Series 6. The Series 6 Shares were redeemed for 25.00 per share in Canadian dollars plus all accrued and unpaid dividends to the date of redemption for a total redemption amount of approximately 104 million Canadian dollars.

In October 2004, Westcoast redeemed all remaining outstanding Cumulative Redeemable First Preferred Shares, Series 9. The Series 9 Shares were redeemed for 25.00 per share in Canadian dollars plus all accrued and unpaid dividends to the date of redemption for a total redemption amount of 125 million Canadian dollars.

*Available Credit Facilities and Restrictive Debt Covenants.* As of December 31, 2004, credit facilities capacity was reduced by approximately $560 million compared to December 31, 2003, primarily related to the divested Asia-Pacific Business as discussed in Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale." In addition, Duke Energy and

DEFS renewed and replaced their credit facilities at lower amounts due to the reduced need for credit capacity. In October 2004, Duke Capital added two new credit facilities, including a $120 million bilateral credit facility with an expiration date of July 15, 2009 and a $130 million bilateral credit facility with an expiration date of October 18, 2007. Duke Capital intends to use both of these facilities for issuing letters of credit to support the business activities of its subsidiaries. The issuance of commercial paper, letters of credit and other borrowings reduces the amount available under the credit facilities.

Duke Energy's credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2004, Duke Energy was in compliance with those covenants. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the credit agreements contain material adverse change clauses or any covenants based on credit ratings.

(For information on Duke Energy's credit facilities as of December 31, 2004, see Note 15 to the Consolidated Financial Statements, "Debt and Credit Facilities.")

Duke Energy has approximately $1,300 million of credit facilities which expire in 2005. It is Duke Energy's intent to resyndicate the $1,300 million of expiring credit facilities.

*Credit Ratings.* The most recent change to the credit ratings of Duke Energy, Duke Capital and its subsidiaries occurred in February 2004, when Standard and Poor's (S&P) lowered its long-term ratings of Duke Energy and its subsidiaries (with the exception of Maritimes & Northeast Pipeline, LLC and Maritimes & Northeast Pipeline, LP (collectively, M&N Pipeline) DEFS and DETM) one ratings level. S&P's actions were based upon Duke Energy's weaker than anticipated financial performance in 2003 and the execution risk associated with Duke Energy's 2004 debt reduction plans. Additionally, S&P noted that Duke Energy's continuation of trading and marketing activities around merchant generation will continue to expose Duke Energy to market risk and the need to dedicate material liquidity to support such activities. At the conclusion of S&P's actions, Duke Energy, Duke Capital and its subsidiaries were placed on Stable Outlook, with the exception of DETM, which was changed from Negative Outlook to Stable in July 2004. In addition, S&P changed the outlook of all of Duke Energy and its subsidiaries (with the exception of M&N Pipeline and DEFS) from Stable to Positive in December 2004 and then from Positive to Stable in February 2005. Also, in February 2005, Moody's changed the outlook of Duke Capital and DEFS from Stable to Negative and placed the ratings of M&N Pipeline to under Review for Possible Downgrade. The following table summarizes the March 1, 2005 credit ratings from the agencies retained by Duke Energy to rate its securities, its principal funding subsidiaries and its trading and marketing subsidiary DETM.

**Credit Ratings Summary as of March 1, 2005**

| | Standard and Poor's | Moody's Investor Service | Dominion Bond Rating Service |
|---|---|---|---|
| Duke Energy[a] | BBB | Baa1 | Not applicable |
| Duke Capital LLC[a] | BBB- | Baa3 | Not applicable |
| Duke Energy Field Services[a] | BBB | Baa2 | Not applicable |
| Texas Eastern Transmission, LP[a] | BBB | Baa2 | Not applicable |
| Westcoast Energy Inc.[a] | BBB | Not applicable | A(low) |
| Union Gas Limited[a] | BBB | Not applicable | A |
| Maritimes & Northeast Pipeline, LLC[b] | A | A1 | A |
| Maritimes & Northeast Pipeline, LP[b] | A | A1 | A |
| Duke Energy Trading and Marketing, LLC[c] | BBB- | Not applicable | Not applicable |

*a* Represents senior unsecured credit rating
*b* Represents senior secured credit rating
*c* Represents corporate credit rating

Duke Energy's credit ratings are dependent on, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures and dividends, and a disciplined execution of the stock repurchase program announced in February 2005, while maintaining the strength of its current balance sheet. If, as a result of market conditions or other factors, Duke Energy is unable to maintain its current balance sheet strength, or if its earnings and cash flow outlook materially deteriorates, Duke Energy's credit ratings could be negatively impacted.

Duke Energy and its subsidiaries are required to post collateral under trading and marketing and other contracts. Typically, the amount of the collateral is dependent upon Duke Energy's economic position at points in time during the life of a contract and the credit rating of the subsidiary (or its guarantor, if applicable) obligated under the collateral agreement. Business activity by DENA generates the majority of Duke Energy's collateral requirements. DENA transacts business through DETM or Duke Energy Marketing America, LLC, a wholly owned subsidiary of Duke Capital.

A reduction in DETM's credit rating to below investment grade as of December 31, 2004 would have resulted in Duke Capital posting additional collateral of up to approximately $160 million. Additionally, in the event of a reduction in DETM's credit rating to below investment grade, collateral agreements may require the segregation of cash held as collateral to be placed in escrow. As of December 31, 2004, Duke Capital would have been required to escrow approximately $280 million of such cash collateral held if DETM's credit rating had been reduced to below investment grade. Amounts above reflect Duke Energy's 60% ownership of DETM and the allocation of collateral to DENA for contracts executed by DETM on its behalf.

A reduction in the credit rating of Duke Capital to below investment grade as of December 31, 2004 would have resulted in Duke Capital posting additional collateral of up to approximately $380 million. Additionally, in the event of a reduction in Duke Capital's credit rating to below investment grade, certain interest rate and foreign exchange swap agreements may require settlement payments due to termination of the agreements. As of December 31, 2004, Duke Capital could have been required to pay up to $140 million in such settlement payments if Duke Capital's credit rating had been reduced to below investment grade. Duke Capital would fund any additional collateral requirements through a combination of cash on hand and the use of credit facilities.

If credit ratings for Duke Energy or its affiliates fall below investment grade there is likely to be a negative impact on its working capital and terms of trade that is not possible to quantify fully in addition to the posting of additional collateral and segregation of cash described above.

*Acceleration Clauses.* Duke Energy may be required to repay certain debt should its credit ratings fall to a certain level at S&P or Moody's. As of December 31, 2004, Duke Energy had $17 million of senior unsecured notes which mature serially through 2012 that may be required to be repaid if Duke Energy's senior unsecured debt ratings fall below BBB- at S&P or Baa3 at Moody's, and $28 million of senior unsecured notes which mature serially through 2016 that may be required to be repaid if Duke Energy's senior unsecured debt ratings fall below BBB at S&P or Baa2 at Moody's. As of March 1, 2004, Duke Energy's senior unsecured credit rating was BBB at S&P and Baa1 at Moody's.

*Other Financing Matters.* As of December 31, 2004, Duke Energy and its subsidiaries had effective SEC shelf registrations for up to $2,042 million in gross proceeds from debt and other securities. This represents an increase of approximately $92 million as compared to December 31, 2003, providing future funding flexibility. Of the total amount, $500 million represents available capacity at DEFS. On January 31, 2005 DEFS filed a Form 15 with the SEC to suspend its reporting obligations under the Securities and Exchange Act of 1934. Additionally, as of December 31, 2004, Duke Energy had access to 900 million Canadian dollars (U.S. $747 million) available under the Canadian shelf registrations for issuances in the Canadian market. A shelf registration is effective in Canada for a 25-month period. Of the total amount available under Canadian shelf registrations, 500 million Canadian dollars will expire in November 2005 and 400 million Canadian dollars will expire in July 2006.

Duke Energy's Board of Directors adopted a dividend policy in 2000 that maintains dividends at the current quarterly rate of $0.275 per share, subject to the discretion of the Board of Directors. Duke Energy has paid quarterly cash dividends for 78 consecutive years. Dividends on common and preferred stocks in 2005 are expected to be paid on March 16, June 16, September 16 and December 16, subject to the discretion of the Board of Directors.

Prior to June 2004, Duke Energy's Investor Direct Choice Plan allowed investors to reinvest dividends in common stock and to purchase common stock directly from Duke Energy. In June 2004, Duke Energy changed the method of dividend reinvestment to open market purchases, reducing the issuances of common stock under the plan in 2004 to $36 million. Issuances under this plan were $111 million in 2003 and $105 million in 2002.

Duke Energy also sponsors an employee savings plan that covers substantially all U.S. employees. In April 2004, Duke Energy stopped issuing shares under the plan and the plan began making open market purchases with cash provided by Duke Energy, reducing the issuances of common stock under the plan to $51 million in 2004. Issuances of common stock under these plans were $156 million in 2003 and $188 million in 2002. Duke Energy also issues authorized but unissued shares of its common stock to meet other employee benefit requirements. Issuances of common stock to meet other employee benefit requirements were approximately $12 million for 2004, approximately $20 million for 2003 and approximately $50 million for 2002. (For additional information on stock-based compensation and employee benefit plans, see Note 20 to the Consolidated Financial Statements, "Stock-Based Compensation" and Note 21 to the Consolidated Financial Statements, "Employee Benefit Plan.")

## Off-Balance Sheet Arrangements

Duke Energy and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. These arrangements are largely entered into by Duke Capital. (See Note 18 to the Consolidated Financial Statements, "Guarantees and Indemnifications," for further details of the guarantee arrangements.)

Most of the guarantee arrangements entered into by Duke Energy enhance the credit standing of certain subsidiaries, non-consolidated entities or less than wholly-owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of Duke Energy or Duke Capital having to honor its contingencies is largely dependent upon the future operations of the subsidiaries, investees and other third parties, or the occurrence of certain future events.

Issuance of these guarantee arrangements is not required for the majority of Duke Energy's operations. Thus, if Duke Energy discontinued issuing these guarantee arrangements, there would not be a material impact to the consolidated results of operations, cash flows or financial position.

Duke Energy does not have any material off-balance sheet financing entities or structures, except for normal operating lease arrangements and guarantee arrangements. (For additional information on these commitments, see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies" and Note 18 to the Consolidated Financial Statements, "Guarantees and Indemnifications.")

### Contractual Obligations

Duke Energy enters into contracts that require payment of cash at certain specified periods, based on certain specified minimum quantities and prices. The following table summarizes Duke Energy's contractual cash obligations for each of the periods presented. The table below excludes all amounts classified as current liabilities on the Consolidated Balance Sheets, other than current maturities of long-term debt. It is expected that the majority of current liabilities on the Consolidated Balance Sheets will be paid in cash in 2005.

**Contractual Obligations as of December 31, 2004**

| | Payments Due By Period | | | | |
|---|---|---|---|---|---|
| | Total | Less than 1 year (2005) | 2-3 Years (2006 & 2007) | 4-5 Years (2008 & 2009) | More than 5 Years (Beyond 2009) |
| | | | (in millions) | | |
| Long-term debt[(a)] | $29,558 | $2,850 | $ 4,694 | $4,108 | $17,906 |
| Capital leases[(a)] | 195 | 119 | 28 | 30 | 18 |
| Operating leases[(b)] | 530 | 94 | 137 | 92 | 207 |
| Purchase Obligations: | | | | | |
| Firm capacity payments[(c)] | 2,047 | 380 | 419 | 290 | 958 |
| Energy commodity contracts[(d)] | 11,746 | 4,948 | 4,321 | 1,412 | 1,065 |
| Other purchase obligations[(e)] | 1,973 | 800 | 369 | 136 | 668 |
| Other long-term liabilities on the Consolidated Balance Sheets[(f)] | 716 | 182 | 275 | 259 | — |
| Total contractual cash obligations | $46,765 | $9,373 | $10,243 | $6,327 | $20,822 |

(a) See Note 15 to the Consolidated Financial Statements, "Debt and Credit Facilities". Amount also includes interest payments over life of debt.
(b) See Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies".
(c) Includes firm capacity payments that provide Duke Energy with uninterrupted firm access to natural gas transportation and storage, electricity transmission capacity, refining capacity and the option to convert natural gas to electricity at third-party owned facilities (tolling arrangements) in some natural gas and power locations throughout North America. Also includes firm capacity payments under electric power agreements entered into to meet Franchised Electric's native load requirements.
(d) Includes contractual obligations to purchase physical quantities of electricity, natural gas, NGLs, coal and nuclear fuel. Amount includes certain normal purchases, energy derivatives and hedges per SFAS No. 133. For contracts where the price paid is based on an index, the amount is based on forward market prices at December 31, 2004. For certain of these amounts, Duke Energy may settle on a net cash basis since Duke Energy has entered into payment netting agreements with counterparties that permit Duke Energy to offset receivables and payables with such counterparties. A significant portion of these amounts pertain to DENA's physical purchase commitments of electricity. Since DENA primarily markets electricity, consideration should be given to DENA's forward sales of electricity, which exceed their forward purchases, when assessing the potential implications of these physical purchase commitments.
(e) Includes purchase commitments for outsourcing of certain real estate services, contracts for software, telephone, data and consulting or advisory services. Amount also includes contractual obligations for engineering, procurement and construction costs for nuclear plant refurbishments, environmental projects on fossil facilities, pipeline and real estate projects, and major maintenance of certain merchant plants. Amount excludes certain open purchase orders for services that are provided on demand, and the timing of the purchase can not be determined.
(f) Includes expected retirement plan contributions for 2005 (see Note 21 to the Consolidated Financial Statements, "Employee Benefit Plan,") certain estimated executive benefits, Department of Energy assessment fee (see Note 4 to the Consolidated Financial Statements, "Regulatory Matters,") and asset retirement obligations and contributions to the Nuclear Decommissioning Trust Funds (see Note 7 to the Consolidated Financial Statements, "Asset Retirement Obligations.")

Duke Energy has not determined these amounts beyond 2009. Since the majority of asset retirement obligations will settle beyond 2009, they are excluded. Amount excludes reserves for litigation, environmental remediation, asbestos-related injuries and damages claims and self-insurance claims (see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies") because Duke Energy is uncertain as to the timing of when cash payments will be required. Additionally, amount excludes annual insurance premiums that are necessary to operate the business, including nuclear insurance (see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies,") funding of other post-employment benefits (see Note 21 to the Consolidated Financial Statements, "Employee Benefit Plan") and regulatory credits (see Note 4 to the Consolidated Financial Statements, "Regulatory Matters") because the amount and timing of the cash payments are uncertain. Also amount excludes Deferred Income Taxes and Investment Tax Credits on the Consolidated Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year. Liabilities Associated with Assets Held for Sale (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale") are also excluded as Duke Energy expects these liabilities will be assumed by the buyer upon sale of the assets.

## Quantitative and Qualitative Disclosures About Market Risk

### Risk and Accounting Policies

Duke Energy is exposed to market risks associated with commodity prices, credit exposure, interest rates, equity prices and foreign currency exchange rates. Management has established comprehensive risk management policies to monitor and manage these market risks. Duke Energy's Chief Executive Officer and Chief Financial Officer are responsible for the overall approval of market risk management policies and the delegation of approval and authorization levels. The Executive Committee which is composed of senior executives, receives periodic updates from the Chief Risk Officer (CRO) and other members of management, on market risk positions, corporate exposures, credit exposures and overall risk management activities. The CRO is responsible for the overall governance of managing credit risk and commodity price risk, including monitoring exposure limits.

See Critical Accounting Policies—Risk Management Accounting and Revenue Recognition—Trading and Marketing Revenues for further discussion of the accounting for derivative contracts.

### Commodity Price Risk

Duke Energy is exposed to the impact of market fluctuations in the prices of natural gas, electricity, NGLs and other energy-related products marketed and purchased as a result of its ownership of energy related assets, remaining proprietary trading contracts, and interests in structured contracts classified as undesignated. Duke Energy employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity derivatives, including forward contracts, futures, swaps and options. (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies" and Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments.")

Validation of a contract's fair value is performed by an internal group independent of Duke Energy's trading areas. While Duke Energy uses common industry practices to develop its valuation techniques, changes in Duke Energy's pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition.

*Hedging Strategies.* Duke Energy closely monitors the risks associated with these commodity price changes on its future operations and, where appropriate, uses various commodity instruments such as electricity, natural gas, crude oil and NGL forward contracts to mitigate the effect of such fluctuations on operations. Duke Energy's primary use of energy commodity derivatives is to hedge the output and production of assets and other contractual positions it owns.

To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the Consolidated Statements of Operations until delivery or settlement occurs. Accordingly, assumptions and valuation techniques for these contracts have no impact on reported earnings prior to settlement. Several factors influence the effectiveness of a hedge contract, including counterparty credit risk and using contracts with different commodities or unmatched terms. Hedge effectiveness is monitored regularly and measured each month. (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies" and Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments.")

In addition to the hedge contracts described above and recorded on the Consolidated Balance Sheets, Duke Energy enters into other contracts that qualify for the normal purchases and sales exemption described in Paragraph 10 of SFAS No. 133 and DIG Issue No. C15. For contracts qualifying for the scope exception, no recognition of the contract's fair value in the Consolidated Financial Statements is required until settlement of the contract unless the contract is designated as the hedged item in a fair value hedge. Normal purchases and sales contracts are generally subject to collateral requirements under the same credit risk reduction guidelines used for other contracts. Duke Energy has applied this scope exception for certain contracts involving the purchase and sale of electricity at fixed prices in future periods. As discussed in Critical Accounting Policies and Estimates for risk management activities, Duke Energy determined that substantially all forward contracts to sell power entered into after July 1, 2003 will be designated as cash flow hedges. Income statement recognition for the contracts will be the same regardless of whether the contracts are accounted for as cash flow hedges or as normal purchases and sales, unless designated as the hedged item in a fair value hedge, assuming no hedge ineffectiveness. The unrealized loss associated with DENA power forward sales contracts designated under the normal purchases and normal sales exemption as of December 31, 2004 and 2003 was approximately $900 million and $700 million, respectively. This unrealized loss represents the difference in the normal purchases and normal sales contract prices compared to the forward market prices of power, and is partially offset by unrealized gains on natural gas positions of approximately $800 million and $400 million at December 31, 2004 and 2003, respectively, which are recorded on the Consolidated Balance Sheet in Unrealized Gains and Losses on Mark-to-Market and Hedging Transactions. However, a key objective for Duke Energy in 2005 is to position DENA to be a successful merchant operator. Duke Energy is pursuing various options to create a sustainable business model for DENA, including consideration of potential business partners. Depending on the option selected, there is a risk that material impairments or other losses could be recorded, including the potential disqualification of DENA's power forward sales contracts designated under the normal purchases and normal sales exemption. This would result in the recognition of all unrealized losses associated with these forward contracts. (For more information, see discussion in Overview of Business Strategy in Introduction section of Management's Discussion and Analysis).

Income recognition and realization related to normal purchases and normal sales contracts generally coincide with the physical delivery of power. However, Duke Energy's decision to sell DENA's Southeast Plants and reduce DENA's interest in partially completed plants required the reassessment of all associated derivatives, including normal purchases and normal sales. This required a change from the application of the Accrual Model to the MTM Model for these contracts and resulted in recording substantial unrealized losses that had not previously been recognized in the Consolidated Financial Statements. Future decisions about Duke Energy's ownership of assets may result in additional contracts related to commodity price risk being recognized in the Consolidated Financial Statements through a charge or credit to earnings.

Based on a sensitivity analysis as of December 31, 2004, it was estimated that a difference of one cent and ten cents per gallon in the average price of NGLs in 2005 would have a corresponding effect on operating income of approximately $5 million and $48 million respectively (at Duke Energy's 70% ownership), after considering the effect of Duke Energy's commodity hedge positions. Comparatively, the same sensitivity analysis as of December 31, 2003 estimated that operating income would have changed by approximately $6 million and $62 million for a one cent and ten cents per gallon difference in the average price of NGLs in 2004, respectively. The effect on operating income for 2005 or 2004 was also not expected to be material as of December 31, 2004 or 2003 for exposures to other commodities' price changes. These hypothetical calculations consider existing hedge positions and estimated production levels, but do not consider other potential effects that might result from such changes in commodity prices.

As a result of the high probability of Duke Energy deconsolidating its investment in DEFS, during the first quarter of 2005 Duke Energy has discontinued hedge accounting for certain 2005 and 2006 contracts held by Duke Energy related to Field Services' commodity risk, which were previously accounted for as cash flow hedges. As a result, approximately $140 million of pretax deferred losses in AOCI related to these contracts have been charged against earnings by Duke Energy in the first quarter of 2005. On a prospective basis, these contracts will be accounted for under the MTM Model and Duke Energy's future earnings for 2005 and 2006 will be subject to more volatility.

*Trading and Undesignated Contracts.* The risk in the MTM portfolio is measured and monitored on a daily basis utilizing a Value-at-Risk model to determine the potential one-day favorable or unfavorable Daily Earnings at Risk (DER) as described below. DER is monitored daily in comparison to established thresholds. Other measures are also used to limit and monitor risk in the trading portfolio on monthly and annual bases. These measures include limits on the nominal size of positions and periodic loss limits.

DER computations are based on historical simulation, which uses price movements over an eleven day period. The historical simulation emphasizes the most recent market activity, which is considered the most relevant predictor of immediate future market movements for natural gas, electricity and other energy-related products. DER computations use several key assumptions, including a 95% confidence level for the resultant price movement and the holding period specified for the calculation. Duke Energy's DER amounts for commodity derivatives recorded using the MTM Model are shown in the following table.

**Daily Earnings at Risk (in millions)**

| | Period Ending One-Day Impact on Operating Income for 2004 | Estimated Average One-Day Impact on Operating Income for 2004 | Estimated Average One-Day Impact on Operating Income for 2003 | High One-Day Impact on Operating Income for 2004[b] | Low One-Day Impact on Operating Income for 2004 |
|---|---|---|---|---|---|
| Calculated DER[a] | $6 | $16 | $8 | $49 | $5 |

(a) DER measures the MTM portfolio's impact on earnings. While this calculation includes both trading and undesignated contracts, the trading portion, as defined by EITF Issue No. 02-03, is not material.
(b) This occurred on January 16, 2004.

DER is an estimate based on historical price volatility. Actual volatility can exceed assumed results. DER also assumes a normal distribution of price changes; thus, if the actual distribution is not normal, the DER may understate or overstate actual results. DER is used to estimate the risk of the entire portfolio, and for locations that do not have daily trading activity, it may not accurately estimate risk due to limited price information. Stress tests are employed in addition to DER to measure risk where market data information is limited. In the current DER methodology, options are modeled in a manner equivalent to forward contracts which may understate the risk. The increase in estimated average DER for 2004 versus 2003 is primarily attributable to the DENA disqualified hedges included in the DER calculation for the full year in 2004 and only a portion of 2003 due to the timing of associated plant impairments and deferrals which resulted in the hedge disqualification.

During the first quarter of 2005, Duke Energy discontinued hedge accounting for certain contracts held by Duke Energy related to Field Services' commodity risk. Since these contracts will be accounted for under the MTM Model prospectively, Duke Energy's 2005 DER figures are expected to be higher than the period ending 2004 DER and may, on average, be higher than the estimated average 2004 DER.

Duke Energy's exposure to commodity price risk is influenced by a number of factors, including contract size, length, market liquidity, location and unique or specific contract terms. The following table illustrates the movement in the fair value of Duke Energy's trading instruments during 2004.

**Changes in Fair Value of Duke Energy's Trading Contracts During 2004**

| | (in millions) |
|---|---|
| Fair value of contracts outstanding at the beginning of the year | $ 177 |
| Contracts realized or otherwise settled during the year | (116) |
| Other changes in fair values | (7) |
| Fair value of contracts outstanding at the end of the year | $ 54 |

**Fair Value of Duke Energy's Trading Contracts as of December 31, 2004**

| Asset/(Liability) Sources of Fair Value | Maturity in 2005 | Maturity in 2006 | Maturity in 2007 | Maturity in 2008 and Thereafter | Total Fair Value |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| Prices supported by quoted market prices and other external sources | $29 | $13 | $(12) | $(17) | $13 |
| Prices based on models and other valuation methods | 18 | 8 | 7 | 8 | 41 |
| Total | $47 | $21 | $ (5) | $ (9) | $54 |

The "prices supported by quoted market prices and other external sources" category includes Duke Energy's New York Mercantile Exchange (NYMEX) futures positions in natural gas, crude oil, propane, heating oil, and unleaded gasoline. The NYMEX has quoted monthly natural gas prices for the next 72 months and quoted monthly crude oil prices for the next 30 months. The NYMEX has quoted monthly prices for varying periods of 18 months or less for propane, heating oil, and unleaded gasoline. In addition, this category includes Duke Energy's forward positions and options in natural gas, natural gas basis swaps, and power at points for which over-the-counter (OTC) broker quotes are available. On average, OTC quotes for power and natural gas forwards and swaps extend 48 months into the future. OTC quotes for natural gas options extend 12 months into the future, on average. Duke Energy values these positions using internally developed forward market price curves that are validated and recalibrated against OTC broker quotes. This category also includes "strip" transactions whose prices are obtained from external sources and then modeled to daily or monthly prices as appropriate.

The "prices based on models and other valuation methods" category includes (i) the value of options not quoted by an exchange or OTC broker, (ii) the value of transactions for which an internally developed price curve was constructed as a result of the long dated nature of the transaction or the illiquidity of the market point, and (iii) the value of structured transactions. In certain instances structured transactions can be decomposed and modeled by Duke Energy as simple forwards and options based on actively quoted prices. Although the valuation of the individual simple structures may be based on quoted market prices, the effective model price for any given period is a combination of prices from two or more different instruments and such transactions therefore are included in this category due to its complex nature. As a result of the adoption of EITF Issue No. 02-03 in January 2003, all of the contracts in the "prices based on models and other valuation methods" category as of December 31, 2004 are derivatives as defined by SFAS No. 133.

**Credit Risk**

Credit risk represents the loss that Duke Energy would incur if a counterparty fails to perform under its contractual obligations. To reduce credit exposure, Duke Energy seeks to enter into netting agreements with counterparties that permit Duke Energy to offset receivables and payables with such counterparties. Duke Energy attempts to further reduce credit risk with certain counterparties by entering into agreements that enable Duke Energy to obtain collateral or to terminate or reset the terms of transactions after specified time periods or upon the occurrence of credit-related events. Duke Energy may, at times, use credit derivatives or other structures and techniques to provide for third-party credit enhancement of Duke Energy's counterparties' obligations.

Duke Energy's principal customers for power and natural gas marketing and transportation services are industrial end-users, marketers, local distribution companies and utilities located throughout the U.S., Canada and Latin America. Duke Energy has concentrations of receivables from natural gas and electric utilities and their affiliates, as well as industrial customers and marketers throughout these regions. These concentrations of customers may affect Duke Energy's overall credit risk in that risk factors can negatively impact the credit quality of the entire sector. Where exposed to credit risk, Duke Energy analyzes the counterparties' financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of those limits on an ongoing basis.

The following table represents Duke Energy's distribution of unsecured credit exposure with the largest 30 enterprise credit exposures at December 31, 2004. These credit exposures are aggregated by ultimate parent company, include on and off balance sheet exposures, are presented net of collateral, and take into account contractual netting rights.

Distribution of Largest 30 Enterprise Credit Exposures
As of December 31, 2004

| | % of Total |
|---|---|
| Investment Grade—Externally Rated | 69% |
| Non-Investment Grade—Externally Rated | 10% |
| Investment Grade—Internally Rated | 16% |
| Non-Investment Grade—Internally Rated | 5% |
| Total | 100% |

"Externally Rated" represents enterprise relationships that have published ratings from at least one major credit rating agency. "Internally Rated" represents those relationships which have no rating by a major credit rating agency. For those relationships, Duke Energy utilizes appropriate risk rating methodologies and credit scoring models to develop an internal risk rating which is intended to map to an external rating equivalent. The total of the unsecured credit exposure included in the table above represents approximately 33% of the gross fair value of Duke Energy's Receivables and Unrealized Gains on Mark-to-Market and Hedging Transactions on the Consolidated Balance Sheet at December 31, 2004.

Duke Energy had no net exposure to any one customer that represented greater than 10% of the gross fair value of trade accounts receivable and unrealized gains on mark-to-market and hedging transactions at December 31, 2004. Based on Duke Energy's policies for managing credit risk, its exposures and its credit and other reserves, Duke Energy does not anticipate a materially adverse effect on its financial position or results of operations as a result of non-performance by any counterparty.

Duke Energy's industry has historically operated under negotiated credit lines for physical delivery contracts. Duke Energy frequently uses master collateral agreements to mitigate certain credit exposures, primarily in its marketing and trading operations. The collateral agreements provide for a counterparty to post cash or letters of credit to the exposed party for exposure in excess of an established threshold. The threshold amount represents an unsecured credit limit, determined in accordance with the corporate credit policy. The collateral agreement also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions.

Duke Energy also obtains cash or letters of credit from customers to provide credit support outside of collateral agreements, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

Collateral amounts held or posted may be fixed or may vary depending on the terms of the collateral agreement and the nature of the underlying exposure and cover trading, normal purchases and normal sales, and hedging contracts outstanding. Duke Energy may be required to return certain held collateral and post additional collateral should price movements adversely impact the value of open contracts or positions. In many cases, Duke Energy's and its counterparties' publicly disclosed credit ratings impact the amounts of additional collateral to be posted. If Duke Energy or its affiliates have a credit rating downgrade, it could result in reductions in Duke Energy's unsecured thresholds granted by counterparties. Likewise, downgrades in credit ratings of counterparties could require counterparties to post additional collateral to Duke Energy and its affiliates. (See Liquidity and Capital Resources—Financing Cash Flows and Liquidity for additional discussion of downgrades.)

The change in market value of NYMEX-traded futures and options contracts requires daily cash settlement in margin accounts with brokers.

**Interest Rate Risk**

Duke Energy is exposed to risk resulting from changes in interest rates as a result of its issuance of variable-rate debt and commercial paper. Duke Energy manages its interest rate exposure by limiting its variable-rate exposures to percentages of total capitalization and by monitoring the effects of market changes in interest rates. Duke Energy also enters into financial derivative instruments, including, but not limited to, interest rate swaps, swaptions and U.S. Treasury lock agreements to manage and mitigate interest rate risk exposure. (See Notes 1, 8, 15, and 16 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments," "Debt and Credit Facilities," and "Preferred and Preference Stock at Duke Energy.")

Based on a sensitivity analysis as of December 31, 2004, it was estimated that if market interest rates average 1% higher (lower) in 2005 than in 2004, interest expense, net of offsetting impacts in interest income, would increase (decrease) by approximately $8 million. Comparatively, based on a sensitivity analysis as of December 31, 2003, had interest rates averaged 1% higher (lower) in 2004 than in 2003, it was estimated that interest expense, net of offsetting impacts in interest income, would have increased (decreased) by approximately $34 million. These amounts were estimated by considering the impact of the hypothetical interest rates on variable-rate securities outstanding, adjusted for interest rate hedges, short-term investments, cash and cash equivalents outstanding as of December 31, 2004 and 2003. The decrease in interest rate sensitivity was primarily due to a decrease in subsidiary debt and a decrease in outstanding variable-rate commercial paper, net of invested cash. If interest rates changed significantly, management would likely take actions to manage its exposure to the change. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no changes in Duke Energy's financial structure.

**Equity Price Risk**

Duke Energy maintains trust funds, as required by the Nuclear Regulatory Commission (NRC), to fund certain costs of nuclear decommissioning. (See Note 7 to the Consolidated Financial Statements, "Asset Retirement Obligations.") As of December 31, 2004 and 2003, these funds were invested primarily in domestic and international equity securities, fixed-rate, fixed-income securities and cash and cash equivalents. Per NRC and Internal Revenue Service mandates, these funds may be used only for activities related to nuclear decommissioning. Those investments are exposed to price fluctuations in equity markets and changes in interest rates. Because the accounting for nuclear decommissioning recognizes that costs are recovered through Franchised Electric's rates, fluctuations in equity prices or interest rates do not affect consolidated results of operations or cash flows.

Bison, Duke Energy's wholly-owned captive insurance subsidiary, maintains investments to fund various business risks and losses, such as workers compensation, property, business interruption and general liability. Those investments are exposed to price fluctuations in equity markets and changes in interest rates.

Duke Energy's costs of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rate, the rate of increase in health care costs and contributions made to the plans. The market value of Duke Energy's defined benefit retirement plan assets has been affected by changes in the equity market since 2000. As a result, at September 30, 2004 (Duke Energy's measurement date), Duke Energy's pension plan obligation, excluding Westcoast, exceeded the value of the plan assets by $130 million and Duke Energy was therefore required to reduce the minimum pension liability as prescribed by SFAS No. 87 and SFAS No. 132, "Employers' Disclosures about Pensions and Postretirement Benefits," by approximately $39 million to $650 million. The $650 million minimum pension liability was a combination of the $130 million excess obligation and $520 million in pre-paid pension assets as of the measurement date of September 30, 2004. The net pension assets as of December 31, 2004 of $120 million, which reflects a fourth quarter 2004 contribution of $250 million is included in Other Investments and Other Assets on the Consolidated Balance Sheets. The minimum liability was recorded as a reduction to AOCI, net of income taxes, and did not affect net income for 2004. When the fair value of the plan assets exceeds the accumulated benefit obligations on the measurement date, the recorded liability will be reduced and AOCI will be restored in the Consolidated Balance Sheets. Also, Westcoast has a $22 million minimum pension liability recorded as of December 31, 2004.

**Foreign Currency Risk**

Duke Energy is exposed to foreign currency risk from investments in international affiliate businesses owned and operated in foreign countries and from certain commodity-related transactions within domestic operations. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. Dollar and/or local inflation rates, or investments may be hedged through debt denominated or issued in the foreign currency. Duke Energy may also use foreign currency derivatives, where possible, to manage its risk related to foreign currency fluctuations. To monitor its currency exchange rate risks, Duke Energy uses sensitivity analysis, which measures the impact of devaluation of the foreign currencies to which it has exposure.

As of December 31, 2004, Duke Energy's primary foreign currency rate exposures were the Canadian Dollar and the Brazilian Real. A 10% devaluation in the currency exchange rate in all of Duke Energy's exposure currencies would result in an estimated net loss on the translation of local currency earnings of approximately $25 million to Duke Energy's Consolidated Statements of Operations. The Consolidated Balance Sheets would be negatively impacted by approximately $450 million currency translation through the cumulative translation adjustment in AOCI.

**OTHER ISSUES**

*Global Climate Change.* The United Nations-sponsored Kyoto Protocol, which prescribes specific greenhouse gas emission-reduction targets for developed countries, became effective February 16, 2005. Of the countries where Duke Energy has assets, Canada is presently the only one that has a greenhouse gas reduction obligation under the Kyoto Protocol. That obligation is to reduce average greenhouse gas emissions to 6 percent below their 1990 level over the period 2008 to 2012. In anticipation of the Kyoto Protocol's entry into force, the Canadian government has been developing an implementation plan that includes, among other things, an emissions intensity-based greenhouse gas cap-and-trade program for large final emitters (LFE). If an LFE program is ultimately enacted, then all of Duke Energy's Canadian operations would likely be subject to the program beginning in 2008, with compliance options ranging from the purchase of $CO_2$ emission credits to actual emission reductions at the source, or a combination of strategies.

In 2001, President George W. Bush declared that the United States would not ratify the Kyoto Protocol. Instead, the U.S. greenhouse gas policy currently favors voluntary actions, continued research, and technology development over near-term mandatory greenhouse gas reduction requirements. Although several bills have been introduced in Congress that would compel $CO_2$ emission reductions, none have advanced through the legislature and presently there are no federal mandatory greenhouse gas reduction requirements. The likelihood of a federally mandated $CO_2$ emissions reduction program being enacted in the near future, or the specific requirements of any such regime, is highly uncertain. Some states are contemplating or have taken steps to manage greenhouse gas emissions, and while a number of U.S. states in the Northeast and far West are discussing the possibility of implementing regional programs in the future, the outcome of such discussions is very uncertain.

Due to the uncertainty of the Canadian policy and the speculative nature of any U.S. federal and state policies, Duke Energy cannot estimate the potential effect of the Canadian greenhouse gas reduction policy currently under development, or the potential effect of U.S.

greenhouse gas policy on future consolidated results of operations, cash flows or financial position. Duke Energy will continue to assess and respond to the potential implications of greenhouse gas policies applicable to its business operations in the United States and Canada.

(For additional information on other issues related to Duke Energy, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters" and Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies.")

**New Accounting Standards**

The following new accounting standards were issued, but have not yet been adopted by Duke Energy as of December 31, 2004:

*SFAS No. 123 (Revised 2004), "Share-Based Payment".* In December of 2004, the FASB issued SFAS No. 123R, which replaces SFAS No. 123 and supercedes Accounting Principles Board (APB) Opinion No. 25. SFAS No. 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values beginning with the first interim or annual period after June 15, 2005. The pro forma disclosures previously permitted under SFAS No. 123 no longer will be an alternative to financial statement recognition. Under SFAS No. 123R, Duke Energy must determine the appropriate fair value model to be used for valuing share-based payments, the amortization method for compensation cost and the transition method to be used at the date of adoption. The transition methods include prospective and retroactive adoption options. Under the retroactive option, prior periods may be restated either as of the beginning of the year of adoption or for all periods presented. The prospective method requires that compensation expense be recorded for all unvested awards at the beginning of the first quarter of adoption of SFAS No. 123R, while the retroactive methods would record compensation expense for all unvested awards beginning in the first period restated.

The impact on earnings per share (EPS) for 2004, 2003 and 2002 had Duke Energy followed the expensing provisions of SFAS No. 123 is discussed in Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies." Duke Energy continues to assess the transition provisions and has not yet determined the transition method to be used nor has Duke Energy determined if any changes will be made to the valuation method used for share-based compensation awards issued to employees in future periods. The impact to Duke Energy in periods subsequent to adopting SFAS 123R will be dependent upon the nature of any equity-based compensation awards issued to employees, but Duke Energy does not anticipate the adoption of SFAS No. 123R on July 1, 2005 to have any material impact on its consolidated results of operations, cash flows or financial position.

*SFAS No. 153, "Exchanges of Nonmonetary Assets—an amendment of APB Opinion No. 29".* In December of 2004, the FASB issued SFAS No. 153 which amends APB Opinion No. 29, "Accounting for Nonmonetary Transactions," by eliminating the exception to the fair-value principle for exchanges of similar productive assets, which were accounted for under APB Opinion No. 29 based on the book value of the asset surrendered with no gain or loss recognition. SFAS No. 153 also eliminates APB Opinion 29's concept of culmination of an earnings process. The amendment requires that an exchange of nonmonetary assets be accounted for at fair value if the exchange has commercial substance and fair value is determinable within reasonable limits. Commercial substance is assessed by comparing the entity's expected cash flows immediately before and after the exchange. If the difference is significant, the transaction is considered to have commercial substance and should be recognized at fair value. SFAS No. 153 is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The impact to Duke Energy of SFAS No. 153 will depend on the nature and extent of any exchanges of nonmonetary assets after the effective date, but Duke Energy does not currently expect SFAS No. 153 to have a material impact on its consolidated results of operations, cash flows or financial position.

*EITF Issue No. 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, 'Accounting for the Impairment or Disposal of Long-Lived Assets', in Determining Whether to Report Discontinued Operations".* In November of 2004, the EITF reached a consensus with respect to evaluating whether the criteria in SFAS No. 144 have been met for classifying as a discontinued operation a component of an entity that either has been disposed of or is classified as held for sale. To qualify as a discontinued operation, SFAS No. 144 requires that the cash flows of the disposed component be eliminated from the operations of the ongoing entity and that the ongoing entity not have any significant continuing involvement in the operations of the disposed component after the disposal transaction. The consensus in EITF Issue No. 03-13 clarifies that the cash flows of the eliminated component are not considered to be eliminated if the continuing cash flows represent "direct" cash flows, as defined in the consensus. The consensus also requires that the assessment of whether significant continuing involvement exists be made from the perspective of the disposed component. The assessment should consider whether (a) the continuing entity retains an interest in the disposed component sufficient to enable it to exert significant influence over the disposed component's operating and financial policies or (b) the entity and the disposed component are parties to a contract or agreement that gives rise to significant continuing involvement by the ongoing entity. The consensus is to be applied prospectively to a component of an entity that is either disposed or classified as held for sale in fiscal periods beginning after December 15, 2004. The impact to Duke Energy of EITF Issue No. 03-13 will depend on the nature and extent of any long-lived assets disposed of or held for sale after the effective date, but Duke Energy does not currently expect EITF Issue No. 03-13 to have a material impact on its consolidated results of operations, cash flows or financial position.

### Subsequent Events

In February 2005, DEFS sold its wholly-owned subsidiary TEPPCO for approximately $1.1 billion and Duke Energy sold its limited partner interest in TEPPCO Partners, L.P. for approximately $100 million, in each case to EPCO, an unrelated third party.

Additionally, in February 2005, Duke Energy executed an agreement with ConocoPhillips whereby Duke Energy has agreed to transfer a 19.7% interest in DEFS to ConocoPhillips for direct and indirect monetary and non-monetary consideration of approximately $1.1 billion. The consideration is expected to consist of the current Canadian operations of DEFS, the transfer of certain Canadian assets from ConocoPhillips to Duke Energy and the transfer of certain U.S. Midstream assets, or cash, from ConocoPhillips to DEFS, and the payment of cash from ConocoPhillips to Duke Energy of at least $500 million. Upon completion of this transaction, DEFS will be owned 50% by Duke Energy and 50% by ConocoPhillips. As a result, Duke Energy expects to account for its investment in DEFS using the equity method subsequent to closing of the transaction. This transaction, which is subject to customary U.S. and Canadian regulatory approvals, is expected to close in the latter half of 2005.

As a result, Duke Energy expects to deconsolidate its investment in DEFS, subsequent to the closing of the transfer of its 19.7% interest to ConocoPhillips. During the first quarter of 2005 Duke Energy has discontinued hedge accounting for certain 2005 and 2006 contracts held by Duke Energy related to Field Services' commodity risk, which were previously accounted for as cash flow hedges. As a result, approximately $140 million of pretax deferred losses in AOCI related to these contracts have been reclassified into earnings by Duke Energy in the first quarter of 2005. On a prospective basis, these contracts will be accounted for under the MTM Model.

Additionally, in connection with the transactions discussed above, Duke Energy has announced plans to periodically repurchase up to an aggregate of $2.5 billion of common stock over the next three years.

On March 1, 2005, notices were sent to the bondholders of the $100 million PanEnergy 8.625% bonds due in 2025. The bondholders were notified that these securities would be called on April 15, 2005, the earliest date at which these bonds can be redeemed.

On March 9, 2005, Duke Power Company (Duke Power) filed with the North Carolina Utilities Commission a proposed fuel rate increase, for rates effective July 1, 2005 for a twelve-month period. To reduce the impact of the increased cost of fuel, Duke Power is seeking approval in the fuel case proceeding to credit the deferred fuel account by approximately $100 million for previously recorded excess deferred tax liabilities that are recorded as regulatory liabilities. The filing has not yet been approved. No similar action has yet been proposed to the PSCSC.

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

See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk."

## Item 8. Financial Statements and Supplementary Data.

### Management's Annual Report on Internal Control Over Financial Reporting

Duke Energy's management is responsible for establishing and maintaining an adequate system of internal controls over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Duke Energy's management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2004 based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2004.

Management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which immediately follows.

March 16, 2005

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Duke Energy Corporation:

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, that Duke Energy Corporation and subsidiaries (Duke Energy) maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Duke Energy's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of Duke Energy's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that Duke Energy maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, Duke Energy maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2004 of Duke Energy and our report dated March 16, 2005 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding Duke Energy's agreement in February 2005 to sell its interests in TEPPCO to Enterprise GP Holdings L.P. and to transfer a 19.7% interest in Duke Energy Field Services to ConocoPhillips.

DELOITTE & TOUCHE LLP
Charlotte, North Carolina
March 16, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Duke Energy Corporation:

We have audited the accompanying consolidated balance sheets of Duke Energy Corporation and subsidiaries (Duke Energy) as of December 31, 2004 and 2003, and the related consolidated statements of operations, common stockholders' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of Duke Energy's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Duke Energy at December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1, Duke Energy adopted the provisions of Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," as of January 1, 2002. As discussed in Note 1 and Note 7, Duke Energy adopted the provisions of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," as of January 1, 2003. As discussed in Note 1, Duke Energy adopted the provisions of Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," as of July 1, 2003. As discussed in Note 1, Note 15, and Note 16, Duke Energy adopted the provisions of Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," as of July 1, 2003. As discussed in Note 1, Duke Energy adopted the provisions of Emerging Issues Task Force No. 02-03, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," as of January 1, 2003.

As discussed in Note 23, Duke Energy agreed in February 2005 to sell its interests in TEPPCO to Enterprise GP Holdings L.P. and to transfer a 19.7% interest in Duke Energy Field Services to ConocoPhillips.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Duke Energy's internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 16, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of Duke Energy's internal control over financial reporting and an unqualified opinion on the effectiveness of the Duke Energy's internal control over financial reporting.

DELOITTE & TOUCHE LLP
Charlotte, North Carolina
March 16, 2005

DUKE ENERGY CORPORATION

## Consolidated Statements of Operations
## (In millions, except per-share amounts)

| | Years Ended December 31, | | |
|---|---|---|---|
| | 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 |

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION

**Consolidated Balance Sheets**

**(In millions)**

| | December 31, 2004 | December 31, 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 |

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION
**Consolidated Balance Sheets—(Continued)**
**(In millions)**

| | December 31, 2004 | December 31, 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 |

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION

**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 |

*See Notes to Consolidated Financial Statements*

DUKE ENERGY CORPORATION

## 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.

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements**
**For the Years Ended December 31, 2004, 2003 and 2002**

## 1. Summary of Significant Accounting Policies

**Nature of Operations and Basis of Consolidation.** Duke Energy Corporation (collectively with its subsidiaries, Duke Energy), is a leading energy company located in the Americas with a real estate subsidiary. The Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of Duke Energy, all majority-owned subsidiaries where Duke Energy has control, and those variable interest entities where Duke Energy is the primary beneficiary. The Consolidated Financial Statements also reflect Duke Energy's 12.5% undivided interest in Catawba Nuclear Station.

**Use of Estimates.** To conform with generally accepted accounting principles (GAAP) in the United States, management makes estimates and assumptions that affect the amounts reported in the financial statements and notes. Although these estimates are based on management's best available knowledge at the time, actual results could differ.

**Reclassifications.** Certain prior period amounts have been reclassified to conform to current year presentation. Such reclassifications include the reclassification of income from continuing operations to discontinued operations for certain operations (see Note 13).

The accompanying Consolidated Balance Sheet as of December 31, 2003 reflects a reclassification of instruments used in Duke Energy's cash management program from cash and cash equivalents to short-term investments of $763 million. This reclassification is to present certain auction rate securities and other highly-liquid instruments as short-term investments rather than as cash equivalents due to the stated tenor of the maturities of these investments. Corresponding changes were made to the Consolidated Statements of Cash Flows for the years ended December 31, 2003 and 2002, resulting in reductions of $763 million and $493 million, respectively, in amounts presented as Cash and Cash Equivalents. In the Consolidated Statements of Cash Flows, Cash and Cash equivalents of $493 million at December 31, 2002 was also revised to reflect the reclassification of these instruments from Cash and Cash Equivalents to Short-Term Investments (See Note 9 for further information).

The accompanying Consolidated Balance Sheet as of December 31, 2003 reflects an adjustment of Other within noncurrent assets of $1,020 million, Other Deferred Credits and Other Liabilities of $970 million and Other Current Liabilities of $50 million for a gross-up of insurance receivables and related accrued reserves. This adjustment is related to Duke Energy's contingent exposure related to damages for personal injuries alleged to have arisen from the exposure to or use of asbestos as discussed further in Note 17 and the resulting probable reinsurance recoveries related to Duke Energy's insurance policy covering such losses.

**Cash and Cash Equivalents.** All highly liquid investments with original maturities of three months or less at the date of purchase are considered cash equivalents.

**Short-term Investments.** Duke Energy actively invests a portion of its available cash balances in various financial instruments, such as tax-exempt debt securities that frequently have stated maturities of 20 years or more and tax-exempt money market preferred securities. These instruments provide for a high degree of liquidity through features such as daily and seven day notice put options and 7, 28, and 35 day auctions which allow for the redemption of the investments at their face amounts plus earned income. As Duke Energy intends to sell these instruments within one year or less, generally within 30 days from the balance sheet date, they are classified as current assets. Duke Energy has classified all short-term investments that are debt securities as available-for-sale under Statement of Financial Accounting Standards (SFAS) No. 115, "Accounting For Certain Investments in Debt and Equity Securities," and they are carried at fair market value. Investments in money-market preferred securities that do not have stated redemptions are accounted for at their cost, as they do not have readily determinable fair values. Realized gains and losses and dividend and interest income related to these securities, including any amortization of discounts or premiums arising at acquisition, are included in earnings at the time they are earned.

**Inventory.** Inventory consists primarily of materials and supplies; natural gas and natural gas liquid (NGL) products held in storage for transmission, processing and sales commitments; and coal held for electric generation. This inventory is recorded at the lower of cost or market value, primarily using the average cost method.

DUKE ENERGY CORPORATION
## Notes To Consolidated Financial Statements—(Continued)

**Components of Inventory**

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| | (in millions) | |
| Materials and supplies | $445 | $445 |
| Natural gas | 312 | 299 |
| Coal | 104 | 87 |
| Petroleum products | 81 | 110 |
| Total inventory | $942 | $941 |

**Accounting for Risk Management and Hedging Activities and Financial Instruments.** Duke Energy uses a number of different derivative and non-derivative instruments in connection with its commodity price, interest rate and foreign currency risk management activities and its trading activities, including forward contracts, futures, swaps, options and swaptions. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, are recorded on the Consolidated Balance Sheets at their fair value as Unrealized Gains or Unrealized Losses on Mark-to-Market and Hedging Transactions.

Effective January 1, 2003, in connection with the implementation of the remaining provisions of Emerging Issues Task Force (EITF) Issue No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," Duke Energy designated all energy commodity derivatives as either trading or non-trading. Gains and losses for all derivative contracts that do not represent physical delivery contracts are reported on a net basis in the Consolidated Statements of Operations. For each of the Duke Energy's physical delivery contracts that are derivatives, the accounting model and presentation of gains and losses, or revenue and expense in the Consolidated Statements of Operations is shown below.

| Classification of Contract | Duke Energy Accounting Model | Presentation of Gains & Losses or Revenue & Expense |
|---|---|---|
| ***Trading derivatives*** | Mark-to-market[a] | Net basis in Non-regulated Electric, Natural Gas, NGL, and Other |
| ***Non-trading derivatives:*** | | |
| Cash flow hedge | Accrual[b] | Gross basis in the same income statement category as the related hedged item |
| Fair value hedge | Accrual[b] | Gross basis in the same income statement category as the related hedged item |
| Normal purchase or sale | Accrual[b] | Gross basis upon settlement in the corresponding income statement category based on commodity type |
| Undesignated | Mark-to-market[a] | Net basis in the related income statement category for interest rate, currency and commodity derivative. |

(a) An accounting term used by Duke Energy to refer to derivative contracts for which an asset or liability is recognized at fair value and the change in the fair value of that asset or liability is recognized in the Consolidated Statements of Operations. This term is applied to trading and undesignated non-trading derivative contracts. As this term is not explicitly defined within U. S. Generally Accepted Accounting Principles, Duke Energy's application of this term could differ from that of other companies

(b) An accounting term used by Duke Energy to refer to contracts for which there is generally no recognition in the Consolidated Statements of Operations for any changes in fair value until the service is provided, the associated delivery period occurs or there is hedge ineffectiveness. As discussed further below, this term is applied to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, as well as to non-derivative contracts used for commodity risk management purposes. As this term is not explicitly defined within U. S. Generally Accepted Accounting Principles, Duke Energy's application of this term could differ from that of other companies.

Prior to January 1, 2003, unrealized and realized gains and losses on all energy trading contracts, as defined in EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," which included many derivative and non-derivative instruments, were presented on a net basis in Trading and Marketing Net Margin within Non-regulated Electric, Natural Gas, Natural Gas Liquids, and Other in the Consolidated Statements of Operations. While the income statement presentation of gains and losses, or revenues and expenses for each category of non-trading derivatives, as described above, remained consistent from 2002 to 2003, the definition of a trading and non-trading instrument changed from EITF Issue No. 98-10 to EITF Issue No. 02-03. Under EITF Issue No. 98-10, all energy derivative and non-derivative contracts were considered to be trading that were entered into by an entity's energy trad-

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

ing operations, while under EITF Issue No. 02-03 an assessment is performed for each contract, and only those individual derivative contracts that are entered into with the intent of generating profits on short-term differences in price are considered to be trading. As a result, a significant number of derivatives previously classified as trading under EITF Issue No. 98-10 became classified as non-trading as of January 1, 2003. The significant reduction, as of January 1, 2003, in the volume of derivative and non-derivative contracts that were considered to be trading resulted in presentation of gains and losses, or revenues and expenses for many contracts on a gross basis in 2003 that were presented on a net basis in 2002.

Where Duke Energy's derivative instruments are subject to a master netting agreement and the criteria of the Financial Accounting Standards Board (FASB) Interpretation No. 39 (FIN 39), "Offsetting of Amounts Related to Certain Contracts—An Interpretation of Accounting Principles Board (APB) Opinion No. 10 and FASB Statement No. 105," are met, Duke Energy presents its derivative assets and liabilities, and accompanying receivables and payables, on a net basis in the accompanying Consolidated Balance Sheets.

*Cash Flow and Fair Value Hedges.* Qualifying energy commodity and other derivatives may be designated as either a hedge of a forecasted transaction or future cash flows (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). For all hedge contracts, Duke Energy provides formal documentation of the hedge in accordance with SFAS No. 133. In addition, at inception and on a quarterly basis Duke Energy formally assesses whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. Duke Energy documents hedging activity by transaction type (futures/swaps) and risk management strategy (commodity price risk/interest rate risk).

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included in the Consolidated Statements of Common Stockholders' Equity and Comprehensive Income (Loss) as Accumulated Other Comprehensive Income (Loss) (AOCI) until earnings are affected by the hedged item. Duke Energy discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the Mark-to-Market Model of Accounting (MTM Model) prospectively. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the underlying contract is reflected in earnings; unless it is no longer probable that the hedged forecasted transaction will occur at which time associated deferred amounts in AOCI are immediately recognized in current earnings.

For derivatives designated as fair value hedges, Duke Energy recognizes the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings, to the extent effective, in the current period. All derivatives designated and accounted for as hedges are classified in the same category as the item being hedged in the Consolidated Statements of Cash Flows. In addition, all components of each derivative gain or loss are included in the assessment of hedge effectiveness.

*Normal Purchase and Normal Sales.* From July 1, 2001 through June 30, 2003, Duke Energy applied the normal purchase and normal sale scope exception in Derivative Implementation Group (DIG) Issue C15, "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity" to certain forward sale contracts to deliver electricity. In connection with the adoption of SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," on July 1, 2003, Duke Energy has elected to designate substantially all forward contracts to sell power entered into after July 1, 2003 as cash flow hedges. Contracts that were being accounted for under the normal purchases and normal sales exception under SFAS No. 133 as of June 30, 2003 continue to be accounted for under the normal purchase and normal sales exception as long as the requirements for applying the exception are met. If contracts cease to meet this exception, the fair value of the contracts is recognized on the Consolidated Balance Sheets and the contracts are accounted for using the MTM Model unless immediately designated as a cash flow or fair value hedge.

*Valuation.* When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on internally developed valuation techniques or models. For derivatives recognized under the MTM Model, valuation adjustments are also recognized in the Consolidated Statements of Operations.

**Goodwill.** Duke Energy evaluates the impairment of goodwill under the guidance of SFAS No. 142, "Goodwill and Other Intangible Assets." Under this provision, goodwill is subject to an annual test for impairment. Duke Energy has designated August 31 as the date it performs the annual review for goodwill impairment for its reporting units. Under the provisions of SFAS No. 142, Duke Energy performs the annual review for goodwill impairment at the reporting unit level, which Duke Energy has determined to be an operating segment or one level below.

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**Notes To Consolidated Financial Statements—(Continued)**

Impairment testing of goodwill consists of a two-step process. The first step involves a comparison of the implied fair value of a reporting unit with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves a comparison of the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess. Additional impairment tests are performed between the annual reviews if events or changes in circumstances make it more likely than not that the fair value of a reporting unit is below its carrying amount.

Duke Energy uses a discounted cash flow analysis to determine fair value. Key assumptions in the determination of fair value include the use of an appropriate discount rate, estimated future cash flows and an estimated run rate of general and administrative costs. In estimating cash flows, Duke Energy incorporates current market information, historical factors and fundamental analysis, and other factors into its forecasted commodity prices.

During the quarter ended September 30, 2004, the date of the annual goodwill impairment test for Field Services was changed to August 31st from September 30th. August 31st was selected to perform the annual goodwill impairment test because this earlier date allows Field Services to complete the goodwill impairment test within the same quarter as the testing date. In addition, the change in date will be consistent with the annual goodwill impairment test date used by Duke Energy's other business segments. The change in testing goodwill date did not delay, accelerate or avoid an impairment charge. Accordingly, management believes that the accounting change described above is to a date which is preferable under the circumstances.

**Other Long-term Investments.** Other long-term investments, primarily marketable securities held in the Nuclear Decommissioning Trust Funds (NDTF) and the captive insurance investment portfolio, are classified as available-for-sale securities as management does not have the intent and ability to hold the securities to maturity, nor are they bought and held principally for selling them in the near term. The securities are reported at fair value on Duke Energy's Consolidated Balance Sheets. Unrealized and realized gains and losses, net of tax, on the NDTF are reflected in regulatory assets on Duke Energy's Consolidated Balance Sheets as Duke Energy expects to recover all costs for decommissioning its nuclear generation assets through regulated rates. Unrealized holding gains and losses, net of tax, on all other available-for-sale securities are reflected in AOCI in Duke Energy's Consolidated Balance Sheets until they are realized and reflected in net income.

**Property, Plant and Equipment.** Property, plant and equipment are stated at historical cost less accumulated depreciation. Duke Energy capitalizes all construction-related direct labor and material costs, as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of funds used during construction. The cost of renewals and betterments that extend the useful life of property, plant and equipment is also capitalized. The cost of repairs, replacements and major maintenance projects, which do not extend the useful life or increase the expected output of property, plant and equipment, is expensed as it is incurred. Depreciation is generally computed over the asset's estimated useful life using the straight-line method. The composite weighted-average depreciation rates, excluding nuclear fuel, were 3.81% for 2004, 4.15% for 2003 and 4.32% for 2002. Also, see "Deferred Returns and Allowance for Funds Used During Construction (AFUDC)," discussed below.

When Duke Energy retires its regulated property, plant and equipment, it charges the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization. When it sells entire regulated operating units, or retires or sells non-regulated properties, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded as income, unless otherwise required by the applicable regulatory body.

Duke Energy recognizes asset retirement obligations (ARO) in accordance with SFAS No. 143, "Accounting For Asset Retirement Obligations," for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the estimated useful life of the asset.

**Investments in Residential, Commercial, and Multi-Family Real Estate.** Investments in residential, commercial and multifamily real estate are carried at cost, net of any related depreciation, except for any properties meeting the criteria in SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets," to be presented as Assets Held for Sale in the Consolidated Balance Sheets. Proceeds from sales of residential properties are presented within Operating Revenues and the cost of properties sold are included in Operation, Maintenance and Other in the Consolidated Statements of Operations. Cash flows related to the acquisition, development and disposal of residential properties are included in Cash Flows from Operating Activities in the Consolidated Statements of

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

Cash Flows. Gains and losses on sales of commercial and multifamily properties as well as "legacy" land sales are presented as such in the Consolidated Statements of Operations, and cash flows related to these activities are included in Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows.

**Long-Lived Asset Impairments, Assets Held For Sale and Discontinued Operations.** Duke Energy evaluates whether long-lived assets, excluding goodwill, have been impaired when circumstances indicate the carrying value of those assets may not be recoverable. For such long-lived assets, an impairment exists when its carrying value exceeds the sum of estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used for developing estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on these estimated future cash flows, the impairment loss is measured as the excess of the asset's carrying value over its fair value, such that the asset's carrying value is adjusted to its estimated fair value.

Management assesses the fair value of long-lived assets using commonly accepted techniques, and may use more than one source. Sources to determine fair value include, but are not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. Significant changes in market conditions resulting from events such as changes in commodity prices or the condition of an asset, or a change in management's intent to utilize the asset would generally require management to re-assess the cash flows related to the long-lived assets.

Duke Energy uses the criteria in SFAS No. 144 to determine when an asset is classified as "held for sale." Upon classification as "held for sale," the long-lived asset or asset group is measured at the lower of its carrying amount or fair value less cost to sell, depreciation is ceased and the asset or asset group is separately presented on the Consolidated Balance Sheets.

If an asset or asset group held for sale or sold has clearly distinguishable operations and cash flows, and Duke Energy will not have significant continuing involvement in the operations after the disposal and cash flows of the assets sold have been eliminated from Duke Energy's ongoing operations, then the related results of operations for the current and prior periods, including any related impairments, are reflected as Discontinued Operations, net of tax, in the Consolidated Statements of Operations. If an asset held for sale does not qualify for discontinued operations classification, any impairments and gains or losses on sales are recorded in continuing operations as Gains (Losses) on Sales of Other Assets, net, in the Consolidated Statements of Operations. Impairments for all other long-lived assets, other than goodwill, are recorded as Impairment and Other Related Charges in the Consolidated Statements of Operations.

**Captive Insurance Reserves.** Duke Energy has captive insurance subsidiaries which provide insurance coverage to Duke Energy entities as well as certain third parties, on a limited basis, for various business risks and losses, such as workers compensation, property, business interruption and general liability. Liabilities include provisions for estimated losses incurred, but not yet reported (IBNR), as well as provisions for known claims which have been estimated on a claims-incurred basis. IBNR reserve estimates involve the use of assumptions and are primarily based upon historical loss experience, industry data and other actuarial assumptions. Reserve estimates are adjusted in future periods as actual losses differ from historical experience. Intercompany balances and transactions are eliminated in consolidation.

Duke Energy's captive insurance entities also have reinsurance coverage, which provides reimbursement to Duke Energy for certain losses above a per incident retention. Duke Energy's captive insurance entities also have an aggregate stop-loss insurance coverage, which provides reimbursement from third parties to Duke Energy for its paid losses above certain per line of coverage aggregate amounts during a policy year. Duke Energy recognizes a reinsurance receivable for recovery of incurred losses under its captive's reinsurance and stop-loss insurance coverage once realization of the receivable is deemed probable.

During 2004, Duke Energy eliminated intercompany reserves at its captive insurance subsidiaries of approximately $64 million which was a correction of an accounting error related to prior periods.

**Unamortized Debt Premium, Discount and Expense.** Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the terms of the debt issues. Any call premiums or unamortized expenses associated with refinancing higher-cost debt obligations to finance regulated assets and operations are amortized consistent with regulatory treatment of those items, where appropriate. Certain debt costs were expensed on an accelerated basis in 2003 as required by the Public Service Commission of South Carolina (PSCSC) under the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." (See Cost-Based Regulation below for further discussion of SFAS No. 71.)

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

**Environmental Expenditures.** Duke Energy expenses environmental expenditures related to conditions caused by past operations that do not generate current or future revenues. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Liabilities are recorded when environmental assessments and/or cleanups are probable and the costs can be reasonably estimated.

**Cost-Based Regulation.** Duke Energy accounts for certain of its regulated operations under the provisions of SFAS No. 71. The economic effects of regulation can result in a regulated company recording costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Management continually assesses whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery. These regulatory assets and liabilities are primarily classified in the Consolidated Balance Sheets as Regulatory Assets and Deferred Debits, and Deferred Credits and Other Liabilities. Duke Energy periodically evaluates the applicability of SFAS No. 71, and considers factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, companies may have to reduce their asset balances to reflect a market basis less than cost and write-off their associated regulatory assets and liabilities. (For further information see Note 4).

**Guarantees.** Duke Energy accounts for guarantees and related contracts, for which it is the guarantor, under FASB Interpretation No. 45 (FIN 45), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." In accordance with FIN 45, upon issuance or modification of a guarantee on or after January 1, 2003, Duke Energy recognizes a liability at the time of issuance or material modification for the estimated fair value of the obligation it assumes under that guarantee. Fair value is estimated using a probability-weighted approach. Duke Energy reduces the obligation over the term of the guarantee or related contract in a systematic and rational method as risk is reduced under the obligation. Any additional contingent loss for guarantee contracts is accounted for and recognized in accordance with SFAS No. 5, "Accounting for Contingencies."

Duke Energy has entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time, depending on the nature of the claim. Duke Energy's maximum potential exposure under these indemnification agreements can range from a specified to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Duke Energy is unable to estimate the total maximum potential amount of future payments under these indemnification agreements due to several factors, including uncertainty as to whether claims will be made.

**Stock-Based Compensation.** Duke Energy accounts for its stock-based compensation arrangements under the intrinsic value recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and the FIN 44, "Accounting for Certain Transactions Involving Stock Compensation (an Interpretation of APB Opinion No. 25)." Since the exercise price for all options granted under those plans was equal to the market value of the underlying common stock on the date of grant, no compensation cost is recognized in the accompanying Consolidated Statements of Operations. Restricted stock grants, phantom stock awards and certain stock-based performance awards are recorded over the required vesting period as compensation cost, based on the market value on the date of the grant. Other stock-based performance awards are recorded over the vesting period as compensation cost, and are adjusted for increases and decreases in market value up to the measurement date. Compensation expense for awards with pro-rata vesting is recognized in accordance with FIN 28, "Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans."

The following table shows what earnings available for common stockholders, basic earnings per share and diluted earnings per share would have been if Duke Energy had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," to all stock-based compensation awards and reflects the provisions of SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure (an amendment to SFAS No. 123)."

DUKE ENERGY CORPORATION

**Notes To Consolidated Financial Statements—(Continued)**

**Pro Forma Stock-Based Compensation**

| | For the years ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (in millions, except per share amounts) | | |
| Earnings (loss) available for common stockholders, as reported | $1,481 | $(1,338) | $1,021 |
| Add: stock-based compensation expense included in reported net income (loss), net of related tax effects | 16 | 6 | 9 |
| Deduct: total stock-based compensation expense determined under fair value-based method for all awards, net of related tax effects | (27) | (30) | (70) |
| Pro forma earnings (loss) available for common stockholders, net of related tax effects | $1,470 | $(1,362) | $ 960 |
| Earnings (loss) per share | | | |
| Basic—as reported | $ 1.59 | $ (1.48) | $ 1.22 |
| Basic—pro forma | $ 1.58 | $ (1.51) | $ 1.15 |
| Diluted—as reported | $ 1.54 | $ (1.48) | $ 1.22 |
| Diluted—pro forma | $ 1.53 | $ (1.51) | $ 1.15 |

**Revenue Recognition.** Revenues on sales of electricity, primarily at Franchised Electric, are recognized when the service is provided. Unbilled revenues are estimated by applying an average revenue/kilowatt hour for all customer classes to the number of estimated kilowatt hours delivered, but not billed. Differences between actuals and estimates are immaterial.

Revenues on sales of natural gas, natural gas transportation, storage and distribution as well as sales of petroleum products, primarily at Natural Gas Transmission and Field Services, are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered, but not yet billed, are estimated each month. These estimates are generally based on contract data, regulatory information, estimated distribution usage based on historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month.

Crescent LLC (Crescent) sells residential developed lots in North Carolina, South Carolina, Georgia, Florida, Texas and Arizona. Crescent recognizes revenues from the sale of residential developed lots at closing. Profit is recognized under the full accrual method using estimates of average gross profit per lot within a project or phase of a project based on total estimated project costs. Land and land development costs are allocated to land sold based on relative sales values. Crescent recognizes revenues from commercial and multifamily project sales at closing using the full accrual method. Profit is recognized based on the difference between the sales price and the carrying cost of the project. Crescent develops and sells condominium units in Florida, and revenue is recognized under the percentage-of-completion method.

**Nuclear Fuel.** Amortization of nuclear fuel purchases is included in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power. The amortization is recorded using the units-of-production method.

**Deferred Returns and AFUDC.** Deferred returns, recorded in accordance with SFAS No. 71, represent the estimated financing costs associated with funding regulatory assets. Those costs arise primarily from the funding of purchased capacity costs above levels collected in rates. Deferred returns are non-cash items and are primarily recognized as an addition to purchased capacity costs, which are included in Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets, with an offsetting credit to Other Income and Expenses, net. The amount of deferred returns included in Other Income and Expenses, net was ($9) million in 2004, $6 million in 2003 and $24 million in 2002.

AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities, consists of two components, an equity component and an interest component. The equity component is a non-cash item. AFUDC is capitalized as a component of Property, Plant and Equipment Cost, with offsetting credits to the Consolidated Statements of Operations. After construction is completed, Duke Energy is permitted to recover these costs through inclusion in the rate base and in the depreciation provision. The total amount of AFUDC included in the Consolidated Statements of Operations was $39 million in 2004, which consisted of an equity component of $25 million and an interest expense component of $14 million. The total amount of AFUDC included in the Consolidated Statements of Operations was $108 million in 2003, which consisted of an equity component of $74 million and an interest expense component of $34 million. The total amount of AFUDC included in the Consolidated Statements of Operations was $82 million in 2002, which consisted of an equity component of $55 million and an interest expense component of $27 million.

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

**Income Taxes.** Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and foreign jurisdictional returns as required. Deferred income taxes have been provided for temporary differences between the GAAP and tax carrying amounts of assets and liabilities. These differences create taxable or tax-deductible amounts for future periods. Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties.

Management evaluates and records contingent tax liabilities and related interest based on the probability of ultimately sustaining the tax deductions or income positions. Management assesses the probabilities of successfully defending the tax deductions or income positions based upon statutory, judicial or administrative authority.

**Excise and Other Pass-Through Taxes.** Duke Energy presents revenues net of pass-through taxes on the Consolidated Statements of Operations.

**Segment Reporting.** SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," establishes standards for a public company to report financial and descriptive information about its reportable operating segments in annual and interim financial reports. Operating segments are components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker in deciding how to allocate resources and evaluate performance. Two or more operating segments may be aggregated into a single operating segment provided aggregation is consistent with the objective and basic principles of SFAS No. 131, if the segments have similar economic characteristics, and the segments are considered similar under criteria provided by SFAS No. 131. SFAS No. 131 also establishes standards and related disclosures about the way the operating segments were determined, products and services, geographic areas and major customers, differences between the measurements used in reporting segment information and those used in the company's general-purpose financial statements, and changes in the measurement of segment amounts from period to period. The description of Duke Energy's reportable segments, consistent with how business results are reported internally to management and the disclosure of segment information in accordance with SFAS No. 131, are presented in Note 3.

**Foreign Currency Translation.** The local currencies of Duke Energy's foreign operations have been determined to be their functional currencies, except for certain foreign operations whose functional currency has been determined to be the U.S. Dollar, based on an assessment of the economic circumstances of the foreign operation, in accordance with SFAS No. 52, "Foreign Currency Translation." Assets and liabilities of foreign operations, except for those whose functional currency is the U.S. Dollar, are translated into U.S. Dollars at current exchange rates. Translation adjustments resulting from fluctuations in exchange rates are included as a separate component of AOCI. Revenue and expense accounts of these operations are translated at average exchange rates prevailing during the year. Transaction gains and losses, which were not material for all periods presented, are included in the results of operations of the period in which they occur. Deferred taxes are not provided on translation gains and losses where Duke Energy expects earnings of a foreign operation to be permanently reinvested. Gains and losses relating to derivatives designated as hedges of the foreign currency exposure of a net investment in foreign operations are reported in foreign currency translation as a separate component of AOCI.

**Cumulative Effect of Changes in Accounting Principles.** As of January 1, 2003, Duke Energy adopted the remaining provisions of EITF Issue No. 02-03 and SFAS No. 143. 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 of $162 million, or $0.18 per basic share, as a reduction in earnings.

In October 2002, the EITF reached a final consensus on EITF Issue No. 02-03. Primarily, the final consensus provided for (1) the rescission of the consensus reached on EITF Issue No. 98-10, (2) the reporting of gains and losses on all derivative instruments considered to be held for trading purposes to be shown on a net basis in the income statement, and (3) gains and losses on non-derivative energy trading contracts to be similarly presented on a gross or net basis, in connection with the guidance in EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent."

As a result of the consensus on EITF Issue No. 02-03, Duke Energy recorded a cumulative effect adjustment of $151 million (net of tax and minority interest) in the first quarter 2003 as a reduction to earnings. The recorded value on January 1, 2003 of all non-derivative energy trading contracts that existed on October 25, 2002 were written-off and inventories that were recorded at fair values were adjusted to historical cost. Adopting the final consensus on EITF Issue No. 02-03 did not require a change to prior periods and, therefore, Duke Energy did not change the 2002 classification of operating revenue and operating expense amounts.

In June 2001, the FASB issued SFAS No. 143, which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. For

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

obligations related to non-regulated operations, a cumulative effect adjustment of $11 million (net of tax and minority interest) was recorded in the first quarter of 2003, as a reduction in earnings.

**New Accounting Standards.** The following new accounting standards were adopted by Duke Energy during the year ended December 31, 2004 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

*FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities."* In January 2003, the FASB issued FIN 46 which requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. FIN 46 defines a variable interest entity as an entity in which the equity investors do not have substantive voting rights and there is not sufficient equity at risk for the entity to finance its activities without additional subordinated financial support. The primary beneficiary absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity's activities. In December 2003, the FASB issued FIN 46 (Revised December 2003) (FIN 46R), "Consolidation of Variable Interest Entities—An Interpretation of ARB No. 51," which supercedes and amends the provisions of FIN 46. While FIN 46R retains many of the concepts and provisions of FIN 46, it also provides additional guidance and additional scope exceptions, and incorporates FASB Staff Positions related to the application of FIN 46.

The provisions of FIN 46 applied immediately to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003, while the provisions of FIN 46R were required to be applied to those entities, except for special purpose entities, by the end of the first reporting period ending after March 15, 2004 (March 31, 2004 for Duke Energy). For variable interest entities created, or interests in variable interest entities obtained, on or before January 31, 2003, FIN 46 or FIN 46R was required to be applied to special-purpose entities by the end of the first reporting period ending after December 15, 2003 (December 31, 2003 for Duke Energy), and was required to be applied to all other non-special purpose entities by the end of the first reporting period ending after March 15, 2004 (March 31, 2004 for Duke Energy).

Duke Energy has not identified any material variable interest entities created, or interests in variable entities obtained, after January 31, 2003, which require consolidation or disclosure under FIN 46R. Under the provisions of FIN 46R, effective March 31, 2004, Duke Energy has consolidated certain non-special purpose operating entities, previously accounted for under the equity method of accounting. These entities, which are substantive entities, had total assets of approximately $230 million as of December 31, 2004. In addition, as of December 31, 2004 and 2003, Duke Energy has recorded Net Property, Plant and Equipment of $112 million and $112 million, respectively, and Long-term Debt of $168 million and $157 million, respectively, on the Consolidated Balance Sheets, associated with a variable interest entity that is consolidated by Duke Energy. Duke Energy leases a natural gas processing plant from this entity, and retains all rights and obligations associated with the operations of this plant. This variable interest entity was consolidated on Duke Energy's Consolidated Financial Statements prior to March 31, 2004 (the effective date of FIN46R) primarily due to Duke Energy's guarantee of the residual value of the assets. The impact of consolidating these entities on Duke Energy's consolidated financial statements was not material. Duke Energy adopted the provisions of FIN 46R on December 31, 2003, related to its special-purpose entities consisting of its remaining trust subsidiaries that issued trust preferred securities. Since Duke Energy is not the primary beneficiary of those trust subsidiaries, those entities have been deconsolidated in the accompanying Consolidated Financial Statements. Interest paid to the subsidiary trust is classified as Interest Expense in the accompanying Consolidated Statements of Operations for periods after December 31, 2003. The preferred securities issued by these trusts were repaid during 2004. Additionally, Duke Energy previously had a significant variable interest in, but was not the primary beneficiary of Duke COGEMA Stone & Webster LLC (DCS). However, due to certain contract clarifications pursuant to a contract amendment entered into in April 2004, Duke Energy no longer holds a significant variable interest in DCS.

Various changes and clarifications to the provisions of FIN 46 have been made by the FASB since its original issuance in January 2003. While not anticipated at this time, any additional clarifying guidance or further changes to these complex rules could have an impact on Duke Energy's Consolidated Financial Statements.

*SFAS No. 132 (Revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits."* In December 2003, the FASB revised the provisions of SFAS No. 132 to include additional disclosures related to defined-benefit pension plans and other defined-benefit post-retirement plans, such as the following:

- The long-term rate of return on plan assets, along with a narrative discussion on the basis for selecting the rate of return used
- Information about plan assets for each major asset category (i.e. equity securities, debt securities, real estate, etc.) along with the targeted allocation percentage of plan assets for each category and the actual allocation percentages at the measurement date
- The amount of benefit payments expected to be paid in each of the next five years and the following five-year period in the aggregate

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**Notes To Consolidated Financial Statements—(Continued)**

- The current best estimate of the range of contributions expected to be made in the following year
- The accumulated benefit obligation for defined-benefit pension plans
- Disclosure of the measurement date utilized.

Additionally, interim reports require additional disclosures related to the components of net periodic pension costs and the amounts paid or expected to be paid to the plan in the current fiscal year, if materially different than amounts previously disclosed. The provisions of SFAS No. 132R do not change the measurement or recognition provisions of defined-benefit pension and post-retirement plans as required by previous accounting standards. The provisions of SFAS No. 132R were applied by Duke Energy effective December 31, 2003 with the interim period disclosures applied beginning with the quarter ended March 31, 2004, except for the disclosure provisions of estimated future benefit payments which were effective for Duke Energy for the year ended December 31, 2004. (See Note 21 for the additional related disclosures).

*FASB Staff Position (FSP) FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003."* In May 2004, the FASB staff issued FSP FAS 106-2, which superseded FSP FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." FSP FAS 106-2 provides accounting guidance for the effects of the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Modernization Act). The Modernization Act introduced a prescription drug benefit under Medicare, as well as a federal subsidy to sponsors of retiree health care benefit plans that include prescription drug benefits. FSP FAS 106-2 requires a sponsor to determine if its prescription drug benefits are actuarially equivalent to the drug benefit provided under Medicare Part D as of the date of enactment of the Modernization Act, and if it is therefore entitled to receive the subsidy. If a sponsor determines that its prescription drug benefits are actuarially equivalent to the Medicare Part D benefit, the sponsor should recognize the expected subsidy in the measurement of the accumulated postretirement benefit obligation (APBO) under SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." Any resulting reduction in the APBO is to be accounted for as an actuarial experience gain. The subsidy's reduction, if any, of the sponsor's share of future costs under its prescription drug plan is to be reflected in current-period service cost.

The provisions of FSP FAS 106-2 were effective for the first interim period beginning after June 15, 2004. Duke Energy adopted FSP FAS 106-2 retroactively to the date of enactment of the Modernization Act, December 8, 2003, as allowed by the FSP. (See Note 21 for discussion of the effects of adopting this FSP).

*FSP No. FAS 109-1, "Application of FASB Statement No. 109, 'Accounting for Income Taxes,' to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004".* On October 22, 2004, the President signed the American Jobs Creation Act of 2004 (the Act). The Act provides a deduction for income from qualified domestic production activities, which will be phased in from 2005 through 2010.

Under the guidance in FSP No. FAS 109-1, which was issued in December 2004, the deduction will be treated as a "special deduction" as described in FASB Statement No. 109. As such, for Duke Energy, the special deduction had no material impact on deferred tax assets and liabilities existing at the enactment date. Rather, the impact of this deduction will be reported in the periods in which the deductions are claimed on the tax returns.

*FSP FAS 109-2, "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004".* In addition to the qualified domestic production activities deduction discussed above, the Act creates a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85 percent dividends received deduction for certain dividends from controlled foreign corporations. FSP FAS 109-2, which was issued in December 2004, states that a company is allowed time beyond the financial reporting period of enactment to evaluate the effect of the Act on its plan for reinvestment or repatriation of foreign earnings, as it applies to the application of SFAS No. 109. Although the deduction is subject to a number of limitations and some uncertainty remains as to how to interpret numerous provisions in the Act, Duke Energy believes that it has the information necessary to make an informed decision on the impact of the Act on its repatriation plans. Based on that decision, Duke Energy plans to repatriate approximately $500 million in extraordinary dividends, as defined in the Act, and accordingly has recorded a corresponding tax liability of $45 million as of December 31, 2004. However, Duke Energy has not provided for U.S. deferred income taxes or foreign withholding tax on basis differences in our non-U.S. subsidiaries that result primarily from undistributed earnings of $150 million, which Duke Energy intends to reinvest indefinitely. Determination of the deferred tax liability on these basis differences is not practicable because such liability, if any, is dependent on circumstances existing if and when remittance occurs.

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**Notes To Consolidated Financial Statements—(Continued)**

*EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments."* In March 2004, the EITF reached a consensus on Issue No. 03-1, which provides guidance on assessing whether impairments are other-than-temporary for marketable debt and equity securities accounted for under SFAS No. 115, and non-marketable equity securities accounted for under the cost method. The consensus also requires certain disclosures about unrealized losses that have not been recognized in earnings as other-than-temporary impairments. The disclosure provisions were effective for all periods ending after December 15, 2003. The other-than-temporary impairment application guidance was to be effective for reporting periods beginning after June 15, 2004.

In September 2004, the FASB issued FSP No. EITF Issue 03-1-1, "Effective Date of Paragraphs 10-20 of EITF Issue No. 03-1, 'The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments", which delays indefinitely the application of guidance provisions of EITF Issue No. 03-1 until further application guidance can be considered by the FASB. The FSP did not delay the effective date for the disclosure provisions of EITF No. 03-1. Duke Energy continues to monitor this issue; however, based upon developments to date Duke Energy does not expect the final guidance to have a material impact on its consolidated results of operations, financial position or cash flows.

*EITF Issue No. 04-08, "The Effect of Contingently Convertible Debt on Diluted Earnings per Share."* In September 2004, the EITF reached a consensus on Issue No. 04-8. The consensus requires that the potential common stock related to contingently convertible securities (Co-Cos) with market price contingencies be included in diluted earnings per share calculations using the if-converted method specified in SFAS No. 128, "Earnings per Share," whether the market price contingencies have been met or not. Co-Cos generally require conversion into a company's common stock if certain specified events occur, such as a specified market price for the company's common stock. Prior to the issuance of EITF Issue No. 04-08, Co-Cos were treated as contingently issuable shares under SFAS No. 128, and therefore, the contingencies, must have been met in order for the potential common shares to be included in diluted EPS. Therefore, Co-Cos were only included in diluted EPS during periods in which the contingencies had been met. The consensus is effective for fiscal years ended after December 15, 2004 and is required to be applied retroactively to all periods in which any Co-Cos were outstanding, resulting in restatement of diluted EPS if the impact of the Co-Cos was dilutive.

As discussed in Note 15, Duke Energy issued $770 million par value of contingently convertible notes in May of 2003, bearing an interest rate of 1.75% per annum that contain several contingencies, including a market price contingency that, if met, may require conversion of the notes into Duke Energy common stock. Conversion may be required, at the option of the holder, if any one of the contingencies is met. Therefore, as discussed in Note 19, Duke Energy has included potential common shares of 32.6 million in the calculation of diluted EPS for the periods in which the $770 million contingently convertible notes have been outstanding and for which the impact of conversion was dilutive.

The following accounting standards were adopted by Duke Energy during the year ended December 31, 2003 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

*SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities."* In April 2003, the FASB issued SFAS No. 149, which amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities, including the qualifications for the normal purchases and normal sales exception, under SFAS No. 133. This amendment reflects decisions made by the FASB and the DIG process in connection with issues raised about the application of SFAS No. 133. Generally, the provisions of SFAS No. 149 were to be applied prospectively for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after September 30, 2003. The provisions of SFAS No. 149 which resulted from the DIG process and became effective in quarters beginning before June 15, 2003 continue to be applied based on their original effective dates. Duke Energy adopted the provisions of SFAS No. 149 on July 1, 2003. Certain modifications and changes to the applicability of the normal purchase and normal sales scope exception for contracts to deliver electricity led Duke Energy to re-evaluate its accounting policy for forward sales contracts. As a result, Duke Energy elected to designate substantially all forward contracts to sell power entered into after July 1, 2003 as cash flow hedges on a prospective basis. Contracts that were being accounted for under the normal purchases and normal sales exception under SFAS No. 133 as of June 30, 2003 will continue to be accounted for under such exception, including any modifications to those contracts, as long as the requirements for applying the normal purchases and normal sales exception are met.

*SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity."* In May 2003, the FASB issued SFAS No. 150 which establishes standards for classification and measurement of certain financial instruments with characteristics of both liabilities and equities. Under SFAS No. 150, those instruments are required to be classified as liabilities in the statement of financial position. The financial instruments affected include mandatorily redeemable stock, certain financial instruments that require or may require the issuer to buy back some of its shares in exchange for cash or other assets, and certain obligations that can be

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**Notes To Consolidated Financial Statements—(Continued)**

settled with shares of stock. SFAS No. 150 is effective for all financial instruments entered into or modified after May 31, 2003, and has been applied to Duke Energy's existing financial instruments beginning July 1, 2003.

Duke Energy's financial statements do not include any effects for the application of SFAS No. 150 to non-controlling interests in certain limited-life entities, which are required to be liquidated or dissolved on a certain date, based on the decision of the FASB in November 2003 to defer these provisions indefinitely with the issuance of FASB Staff Position 150-3, "Effective Date, Disclosures, and Transition for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Non-controlling Interests under FASB Statement No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." Duke Energy has a controlling interest in a limited-life entity in Bolivia, which is required to be liquidated 99 years after formation. A non-controlling interest in the entity is held by third parties. Upon termination or liquidation of the entity in 2094, the remaining assets of the entity are to be sold, the liabilities liquidated and any remaining cash distributed to the owners based upon their ownership percentages. As of December 31, 2004 the carrying value of the entity's non-controlling interest of approximately $48 million approximates its fair value. Duke Energy continues to evaluate the potential significance of these aspects of SFAS No. 150, but does not anticipate this will have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position. SFAS No. 150 continues to be interpreted by the FASB and it is possible that significant future changes could be made by the FASB. Therefore, Duke Energy is not able to conclude whether such future changes would materially affect the amounts already recorded and disclosed under the provisions of SFAS No. 150.

*EITF Issue No. 01-08, "Determining Whether an Arrangement Contains a Lease."* In May 2003, the EITF reached consensus in EITF Issue No. 01-08 to clarify the requirements of identifying whether an arrangement should be accounted for as a lease at its inception. The guidance in the consensus is designed to broaden the scope of arrangements accounted for as leases. EITF Issue No. 01-08 requires both parties to an arrangement to determine whether a service contract or similar arrangement is or includes a lease within the scope of SFAS No. 13, "Accounting for Leases." Duke Energy has historically provided and leased storage capacity to outside parties, as well as entered into pipeline and electricity capacity agreements, both as the lessee and as a lessor. The accounting requirements under the consensus may impact the timing of revenue and expense recognition, and amounts previously reported as revenues may be required to be reported as rental or lease income. Should capital lease treatment be necessary, purchasers of transportation, electricity capacity and storage services are required to recognize assets on their balance sheets. The consensus is being applied prospectively to arrangements agreed to, modified, or acquired on or after July 1, 2003. Previous arrangements that would be leases or would contain a lease according to the consensus will continue to be accounted for under historical accounting. The adoption of EITF Issue No. 01-08 did not have a material effect on Duke Energy's consolidated results of operations, cash flows or financial position.

*EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes."* In July 2003, the EITF reached consensus in EITF Issue No. 03-11 that determining whether realized gains and losses on derivative contracts not held for trading purposes should be reported on a net or gross basis is a matter of judgment that depends on relevant facts and circumstances and the economic substance of the transaction. In analyzing those facts and circumstances, EITF Issue No. 99-19, "Reporting Revenue Gross as a Principle versus Net as an Agent," and APB Opinion No. 29, "Accounting for Nonmonetary Transactions," should be considered. EITF Issue No. 03-11 was effective for transactions or arrangements entered into after September 30, 2003. The adoption of EITF Issue No. 03-11 did not have a material effect on Duke Energy's consolidated results of operations, cash flows or financial position.

The following new accounting standards were issued, but have not yet been adopted by Duke Energy as of December 31, 2004:

*SFAS No. 123 (Revised 2004), "Share-Based Payment".* In December of 2004, the FASB issued SFAS No. 123R, which replaces SFAS No. 123 and supercedes APB Opinion 25. SFAS No. 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values beginning with the first interim or annual period after June 15, 2005. The pro forma disclosures previously permitted under SFAS No. 123 no longer will be an alternative to financial statement recognition. Under SFAS No. 123R, Duke Energy must determine the appropriate fair value model to be used for valuing share-based payments, the amortization method for compensation cost and the transition method to be used at the date of adoption. The transition methods include prospective and retroactive adoption options. Under the retroactive option, prior periods may be restated either as of the beginning of the year of adoption or for all periods presented. The prospective method requires that compensation expense be recorded for all unvested awards at the beginning of the first quarter of adoption of SFAS 123R, while the retroactive methods would record compensation expense for all unvested awards beginning in the first period restated.

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**Notes To Consolidated Financial Statements—(Continued)**

The impact on EPS for 2004, 2003 and 2002 had Duke Energy followed the expensing provisions of SFAS No. 123 is discussed above in the Pro Forma Stock-Based Compensation table. Duke Energy continues to assess the transition provisions and has not yet determined the transition method to be used nor has Duke Energy determined if any changes will be made to the valuation method used for share-based compensation awards issued to employees in future periods. The impact to Duke Energy in periods subsequent to adopting SFAS No. 123R will be dependent upon the nature of any equity-based compensation awards issued to employees, but Duke Energy does not anticipate the adoption of SFAS No. 123R on July 1, 2005 to have any material impact on its consolidated results of operations, cash flows or financial position.

*SFAS No. 153, "Exchanges of Nonmonetary Assets—an amendment of APB Opinion No. 29".* In December of 2004, the FASB issued SFAS No. 153 which amends APB Opinion No. 29 by eliminating the exception to the fair-value principle for exchanges of similar productive assets, which were accounted for under APB Opinion No. 29 based on the book value of the asset surrendered with no gain or loss recognition. SFAS No. 153 also eliminates APB Opinion 29's concept of culmination of an earnings process. The amendment requires that an exchange of nonmonetary assets be accounted for at fair value if the exchange has commercial substance and fair value is determinable within reasonable limits. Commercial substance is assessed by comparing the entity's expected cash flows immediately before and after the exchange. If the difference is significant, the transaction is considered to have commercial substance and should be recognized at fair value. SFAS No. 153 is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The impact to Duke Energy of SFAS No. 153 will depend on the nature and extent of any exchanges of nonmonetary assets after the effective date, but Duke Energy does not currently expect SFAS No. 153 to have a material impact on its consolidated results of operations, cash flows or financial position.

*EITF Issue No. 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations".* In November of 2004, the EITF reached a consensus with respect to evaluating whether the criteria in SFAS No. 144 have been met for classifying as a discontinued operation a component of an entity that either has been disposed of or is classified as held for sale. To qualify as a discontinued operation, SFAS No. 144 requires that the cash flows of the disposed component be eliminated from the operations of the ongoing entity and that the ongoing entity not have any significant continuing involvement in the operations of the disposed component after the disposal transaction. The consensus in EITF Issue No. 03-13 clarifies that the cash flows of the eliminated component are not considered to be eliminated if the continuing cash flows represent "direct" cash flows, as defined in the consensus. The consensus also requires that the assessment of whether significant continuing involvement exists be made from the perspective of the disposed component. The assessment should consider whether (a) the continuing entity retains an interest in the disposed component sufficient to enable it to exert significant influence over the disposed component's operating and financial policies or (b) the entity and the disposed component are parties to a contract or agreement that gives rise to significant continuing involvement by the ongoing entity. The consensus is to be applied prospectively to a component of an entity that is either disposed or classified as held for sale in fiscal periods beginning after December 15, 2004. The impact to Duke Energy of EITF Issue No. 03-13 will depend on the nature and extent of any long-lived assets disposed of or held for sale after the effective date, but Duke Energy does not currently expect EITF Issue No. 03-13 to have a material impact on its consolidated results of operations, cash flows or financial position.

## 2. Acquisitions and Dispositions

**Acquisitions.** Duke Energy consolidates assets and liabilities from acquisitions as of the purchase date, and includes earnings from acquisitions in consolidated earnings after the purchase date. Assets acquired and liabilities assumed are recorded at estimated fair values on the date of acquisition. The purchase price minus the estimated fair value of the acquired assets and liabilities meeting the definition of a business as defined in EITF Issue No. 98-3, "Determining Whether a Nonmonetary Transaction Involves Receipt of Productive Assets or of a Business" is recorded as goodwill. The allocation of the purchase price may be adjusted if additional information on known contingencies existing at the date of acquisition becomes available within one year after the acquisition, and longer for certain income tax items.

In the second quarter of 2004, Field Services acquired gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips for a total purchase price of approximately $80 million, consisting of $74 million in cash and the assumption of approximately $6 million of liabilities. As the acquired assets were not considered businesses under the guidance in EITF Issue No. 98-3, no goodwill was recognized in connection with this transaction.

DUKE ENERGY CORPORATION

**Notes To Consolidated Financial Statements—(Continued)**

In the third quarter of 2004, Field Services acquired additional interest in three separate entities (for which Duke Energy Field Services LLC (DEFS) owned less than 100%, but had been consolidating) for a total purchase price of $4 million, and the exchange of some Field Services' assets. Two of these acquisitions, Mobile Bay Processing Partners (MBPP) and Gulf Coast NGL Pipeline, LLC (GC), resulted in 100% ownership by Field Services. The MBPP transaction involved MBPP transferring certain long-lived assets to El Paso Corporation for El Paso Corporation's interest in MBPP. As a result of this non-monetary transaction, the assets transferred were written-down to their estimated fair value which resulted in Duke Energy recognizing a pretax impairment of approximately $13 million, which was approximately $4 million net of minority interest, which is discussed in Note 12. An additional 12% interest in Dauphin Island Gathering Partners (DIGP) was also purchased for $2 million, which resulted in 84% ownership by Field Services. MBPP owns processing assets in the Onshore Gulf of Mexico. GC owns a 16.67% interest in two equity investments. DIGP owns gathering and transmission assets in the Offshore Gulf of Mexico.

The pro forma results of operations for these acquisitions do not materially differ from reported results.

On March 14, 2002, Duke Energy acquired Westcoast Energy Inc. (Westcoast) for approximately $8 billion, including the assumption of $4.7 billion of debt. In the transaction, a Duke Energy subsidiary acquired all of the outstanding common shares of Westcoast in exchange for approximately $1.7 billion in cash (net of cash acquired) and approximately 49.9 million shares of Duke Energy common stock (including exchangeable shares of a Duke Energy Canadian subsidiary that are substantially equivalent to and exchangeable on a one-for-one basis for Duke Energy common stock). The value of the Duke Energy common stock issued was approximately $1.7 billion and was determined based on the average market price of Duke Energy's common shares over the two-day period before and after the terms of the transaction became fixed, in accordance with EITF No. 99-12, "Determination of the Measurement Date for the Market Price of Acquirer Securities Issued in a Purchase Business Combination." Under prorating provisions of the acquisition agreement that ensured that approximately 50% of the total consideration was paid in cash and 50% in stock, each common share of Westcoast entitled the holder to elect to receive 43.80 in Canadian dollars, or either 0.7711 of a share of Duke Energy common stock or of an exchangeable share of a Duke Energy Canadian subsidiary, or a combination thereof. The cash portion of the consideration was funded with the proceeds from the issuance of $750 million in mandatory convertible securities (Equity Units) in November 2001, along with incremental commercial paper. The commercial paper was repaid using the proceeds from the October 2002 public offering of Duke Energy Common Stock.

The acquisition of Westcoast was consistent with Duke Energy's natural gas pipeline strategy to expand its footprint between key supply and market areas in North America. During its evaluation, Duke Energy identified revenue enhancement opportunities through expansion projects and business integration, cost reduction initiatives, and the divestiture of several non-strategic business lines and assets. These initiatives, when combined with the ongoing earnings contributions from Westcoast's pipelines and distribution businesses, supported a purchase price in excess of the fair value of Westcoast's assets, which resulted in the recognition of goodwill. The Westcoast acquisition was accounted for using the purchase method, and goodwill to the Natural Gas Transmission segment of approximately $2.3 billion was recorded in the transaction, of which approximately $57 million was expected to be deductible for income tax purposes. Of the $57 million, $52 million was allocated for tax purposes to Empire State Pipeline which was sold in February 2003.

During 2003, Duke Energy recorded additional purchase price adjustments as information regarding the assets acquired became available, including adjustments related to the sale of Empire State Pipeline and adjustments recorded to reflect the revised tax basis of certain acquired assets, with an offsetting increase to goodwill attributable to the acquisition.

DUKE ENERGY CORPORATION

**Notes To Consolidated Financial Statements—(Continued)**

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed as of the acquisition date, including the adjustments described above.

**Purchase Price Allocation for Westcoast Acquisition**

| | (in millions) |
|---|---|
| Current assets | $ 2,050 |
| Investments and other assets | 1,207 |
| Goodwill | 2,269 |
| Property, plant and equipment | 4,991 |
| Regulatory assets and deferred debits | 809 |
| Total assets acquired | 11,326 |
| Current liabilities | 1,655 |
| Long-term debt | 4,132 |
| Deferred credits and other liabilities | 1,678 |
| Minority interests | 560 |
| Total liabilities assumed | 8,025 |
| Net assets acquired | $ 3,301 |

The following unaudited pro forma consolidated financial results are presented as if the acquisition had taken place at the beginning of the period presented.

**Consolidated Pro Forma Results for Duke Energy, including Westcoast (unaudited)**

| | For the year ended December 31, 2002 |
|---|---|
| | (in millions, except per share amounts) |
| **Income Statement Data** | |
| Operating revenues | $16,216 |
| Net income | 1,071 |
| Preferred and preference stock dividends | 13 |
| Earnings available to common stockholders | $ 1,058 |
| **Common Stock Data** | |
| Weighted-average shares outstanding | 846 |
| Earnings per share | |
| Basic | $ 1.25 |
| Diluted | $ 1.25 |

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

**Dispositions.** The following table details proceeds from the sale of Duke Energy's assets and businesses for 2004, 2003 and 2002.

**Proceeds from Sales of Assets and Businesses**

| | For the years ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (in millions) | | |
| Sales of discontinued operations (see Note 13)[a] | $1,364 | $ 693 | $ 45 |
| Sales which were recorded as purchase price adjustments to the Westcoast acquisition (see above disclosure)[b] | — | 243 | 53 |
| Sales of other assets and businesses[c] | 1,058 | 1,190 | 214 |
| Cash disposed of in sales | — | (16) | — |
| Net proceeds, including debt assumed by buyers and note receivable from buyer | 2,422 | 2,110 | 312 |
| Non-cash debt assumed by buyers and note received from sale of assets | (888) | (387) | — |
| Proceeds included in the Consolidated Statements of Cash Flows[d] | $1,534 | $1,723 | $312 |

(a) 2004 includes approximately $840 million of debt assumed by buyer; 2003 includes $259 million of debt assumed by buyer
(b) 2003 includes $58 million of debt assumed by buyer
(c) 2004 includes $48 million note receivable from buyer; 2003 includes $70 million of debt assumed by buyer
(d) Excludes investing activities related to sales and collections of notes receivable of $8 million for 2004, $243 million for 2003 and $204 million for 2002, and proceeds from sales of Crescent's commercial and multi-family real estate of $606 million for 2004, $314 million for 2003, and $169 million for 2002

For the year ended December 31, 2004, the sale of other assets and businesses (which excludes assets held for sale as of December 31, 2004 and discontinued operations, both of which are discussed in Note 13, and sales by Crescent which are discussed separately below) resulted in approximately $1,010 million in cash proceeds plus a $48 million note receivable from the buyers, and net pre-tax losses of $225 million recorded in (Losses) Gains on Sales of Other Assets, net and pre-tax losses of $4 million recorded in (Losses) Gains on Sales and Impairments of Equity Investments on the Consolidated Statements of Operations. (Losses) Gains on Sales and Impairments of Equity Investments includes a $23 million impairment charge, which is discussed in Note 13. Significant sales of other assets in 2004 are detailed as follows:

- Natural Gas Transmission's asset sales totaled $25 million in net proceeds. Those sales resulted in total pre-tax gains of approximately $33 million, of which $17 million was recorded in (Losses) Gains on Sales of Other Assets, net and $16 million was recorded in (Losses) Gains on Sales and Impairments of Equity Investments in the Consolidated Statements of Operations. Significant sales included the sale of storage gas related to the Canadian distribution operations, the sale of Natural Gas Transmission's interest in the Millennium Pipeline, and the sale of land.
- Field Services asset sales totaled $13 million in net proceeds. Those sales resulted in gains of $2 million which were recorded in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statements of Operations. These sales consisted of multiple small sales.
- Duke Energy North America's (DENA's) asset sales totaled approximately $798 million in net proceeds and a $48 million note receivable. Those sales resulted in pre-tax losses of $248 million which were recorded in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statements of Operations. Significant sales included:
  - DENA's eight natural gas-fired merchant power plants in the southeastern United States: Hot Spring (Arkansas); Murray and Sandersville (Georgia); Marshall (Kentucky); Hinds, Southaven, Enterprise and New Albany (Mississippi); and certain other power and gas contracts (collectively, the Southeast Plants). Duke Energy decided to sell the Southeast Plants in 2003, and recorded an impairment charge of $1.3 billion in 2003 since the assets' carrying values exceeded their estimated fair values (see Note 12). The sale of those assets to KGen Partners LLC (KGen) obtained all required regulatory approvals and consents and closed on August 5, 2004. This transaction resulted in a pre-tax loss of approximately $360 million recorded in (Losses) Gains on Sales of Other Assets, net in the 2004 Consolidated Statement of Operations. Nearly all of the loss was recognized in the first quarter of 2004 to reduce the assets' carrying values to their estimated fair values, and approximately $4 million of the loss was recognized in the third quarter of 2004 upon closing. The fair value of the plants used for recording the loss in the first quarter was based on

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

the sales price of approximately $475 million, as announced on May 4, 2004. The actual sales price consisted of $420 million of cash and a $48 million note receivable from KGen, which bears variable interest at the London Interbank Offered Rate (LIBOR) plus 13.625% per annum, compounded quarterly. The note is secured by a fourth lien on (i) substantially all of KGen's assets and (ii) stock of KGen LLC (KGen's owner), each subject to certain permitted liens and a first lien on cash in certain KGen accounts. The note matures with a balloon payment of all principal and interest due no later than 7 years and 6 months after the closing date.

Duke Capital LLC (Duke Capital) retains certain guarantees related to the sold assets. In conjunction with the sale, Duke Capital arranged a letter of credit with a face amount of $120 million in favor of Georgia Power Company, to secure obligations of a KGen subsidiary under a seven-year power sales agreement, commencing in May 2005, under which KGen will provide power from one of the plants to Georgia Power. Duke Capital is the primary obligor to the letter of credit provider, but KGen has an obligation to reimburse Duke Capital for any payments made by it under the letter of credit, as well as expenses incurred by Duke Capital in connection with the letter of credit. DENA will continue to provide services under a long-term operating agreement for one of the plants. As a result of DENA's significant continuing involvement in the operations of the plants, this transaction did not qualify for discontinued operations presentation, as prescribed by SFAS No. 144. However, this continuing involvement does not prohibit sale accounting under SFAS No. 66, "Accounting for Sales of Real Estate."

- Some turbines and surplus equipment. This sale was anticipated in 2003 and therefore a loss of $66 million was recorded in (Losses) Gains on Sales of Other Assets, net in the 2003 Consolidated Statement of Operations.
- Some Duke Energy Trading and Marketing, LLC (DETM) contracts. DETM held a net liability position in those contracts and, as part of the sale, DETM paid a third party an amount approximating the carrying value of the contracts. The net cash payments of $99 million related to the sale of these assets are included in Cash Flows from Operating Activities. This resulted in a net loss of $65 million recorded in (Losses) Gains on Sales of Other Assets, net in the 2004 Consolidated Statement of Operations.
- A 25% undivided interest in DENA's Vermillion facility. This sale was anticipated in 2003 and therefore losses of $18 million were recorded in (Losses) Gains on Sales of Other Assets, net in the 2003 Consolidated Statement of Operations. Duke Energy still owns the remaining 75% interest in the Vermillion facility.
- The partially completed Moapa facility to Nevada Power Company. This sale resulted in $186 million in net proceeds and a pre-tax gain of approximately $140 million recorded in (Losses) Gains on Sales of Other Assets, net in the 2004 Consolidated Statement of Operations. An impairment charge for $515 million was recorded for this facility in 2003. This asset was not reported in Discontinued Operations in the Consolidated Statement of Operations as, among other considerations, it never entered into operations and had no associated historical operating revenues or significant costs.
- The partially completed Luna facility to PNM Resources, Tucson Electric Power and Phelps Dodge Corporation. This sale resulted in net proceeds of $40 million and a pre-tax gain of $40 million recorded in (Losses) Gains on Sales of Other Assets, net in the 2004 Consolidated Statements of Operations. An impairment charge for $270 million was recorded for this facility in 2003. This asset was not reported in Discontinued Operations in the Consolidated Statement of Operations as, among other considerations, it never entered into operations and had no associated historical operating revenues or significant costs.
- On December 27, 2004, Duke Energy reached an agreement to sell its Grays Harbor partially completed facility to an affiliate of Invenergy LLC for $21 million plus other contingent considerations. Total sales proceeds and tax benefits for this transaction, excluding any potential contingent consideration, will be approximately $116 million. The sale is expected to be completed in the first or second quarter of 2005 and an approximate gain of $20 million will be reported in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statement of Operations. This asset is not reported in Discontinued Operations in the Consolidated Statement of Operations as, among other considerations, it never entered into operations and had no associated historical operating revenues or significant costs. An impairment charge for $362 million was recorded for this facility in 2003. Effective December 31, 2004, Duke Energy terminated its capital lease associated with the dedicated pipeline which would have transported natural gas to the plant. This termination substantially offsets the expected proceeds and tax benefits from the sale of the partially completed Grays Harbor facility and resulted in a $20 million charge in 2004.
- International Energy completed the sale of its 30% equity interest in Compañia de Nitrógeno de Cantarell, S.A. de C.V. (Cantarell) a nitrogen production and delivery facility in the Bay of Campeche, Gulf of Mexico on September 8, 2004. The sale resulted in $60 million in net proceeds and an approximate $2 million pre-tax gain recorded to (Losses) Gains on Sales and Impairments of Equity

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

Investments on the Consolidated Statements of Operations. A $13 million non-cash charge to Operation, Maintenance and Other expenses on the Consolidated Statements of Operations, related to a note receivable from Cantarell, was recorded in the first quarter of 2004.

- Additional asset and business sales in 2004 totaled $114 million in net proceeds. Those sales resulted in net pre-tax gains of $5 million, of which $4 million was recorded in (Losses) Gains on Sales of Other Assets, net and $1 million was recorded in (Losses) Gains on Sales and Impairments of Equity Investments in the Consolidated Statements of Operations. Significant sales included Duke Energy Royal LLC's interest in six energy service agreements, DukeSolutions Huntington Beach LLC, and Duke Energy Merchant LLC's (DEM's) 15% ownership interest in Caribbean Nitrogen Company. DEM also sold its refined products operation in the eastern United States.

For the year ended December 31, 2004, Crescent's commercial and multi-family real estate sales resulted in $606 million of proceeds, and $192 million of net gains recorded in Gains on Sales of Investments in Commercial and Multi-Family Real Estate on the Consolidated Statements of Operations. Significant sales included commercial project sales, resulting primarily from the sale of a commercial project in the Washington, D.C. area in March; real estate sales due primarily to the sale of the Alexandria and Arlington land tracts in the Washington, D.C. area; and several large land tract sales.

The sale of other assets and businesses for approximately $1,120 million in proceeds plus the assumption of $70 million of debt by the buyers for 2003 resulted in net losses of $111 million recorded in (Losses) Gains on Sales of Other Assets, net on the Consolidated Statements of Operations, and gains of $279 million recorded in (Losses) Gains on Sales and Impairments of Equity Investments in the Consolidated Statements of Operations. Significant sales of other assets and businesses in 2003 (other than discontinued operations as presented in Note 13, and sales which were recorded as purchase price adjustments to the Westcoast acquisition as presented above) are detailed by business segment as follows:

- Natural Gas Transmission's sales of assets and businesses totaled $610 million in proceeds, and the assumption of $70 million of debt by the buyers. Those sales resulted in gains of $90 million which were recorded in (Losses) Gains on Sales and Impairments of Equity Investments in the Consolidated Statements of Operations, and gains of $7 million which were recorded in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statements of Operations. Significant sales included the sale of its remaining limited partnership interests in Northern Border Partners L.P.; the sale of its investments in the Alliance Pipeline and the associated Aux Sable NGL plant, Foothills Pipe Lines Ltd., and Vector Pipeline LP (Vector); the sale of Pacific Northern Gas Ltd., and the sale of two office buildings.
- Field Services sales of assets totaled $141 million in proceeds. Those sales resulted in gains of $11 million which were recorded in (Losses) Gains on Sales and Impairments of Equity Investments in the Consolidated Statements of Operations. Significant sales included Field Services' Class B units of TEPPCO Partners, L.P.
- DENA's asset sales totaled $372 million in proceeds. The sale of DENA's 50% ownership interest in Duke/UAE Ref-Fuel LLC (Ref-Fuel) resulted in a gain of $178 million, which was recorded in (Losses) Gains on Sales and Impairments of Equity Investments in the Consolidated Statements of Operations.
- Impairment charges and net losses on sales, primarily related to the sale of DETM contracts, resulted in a net loss of $124 million, which was recorded in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statements of Operations. Impairment charges and losses on the DETM contracts resulted from DENA's decision to wind-down DETM's operations. As a result, DENA and ExxonMobil, its partner, are executing a reduction of DETM business in scope and scale and soliciting interest from selected parties for a significant portion of DETM's contract portfolio. The ultimate financial impact to DENA of the reduction in the scope and sale of DETM and related liquidation of its contract portfolio cannot be reasonably estimated. However, it is possible that DENA will incur additional losses as a result of liquidating the DETM contracts.

The sale of other assets and businesses for approximately $214 million in gross proceeds for 2002 resulted in gains of $32 million recorded in (Losses) Gains on Sales of Other Assets, net on the Consolidated Statement of Operations, and gains of $32 million recorded in (Losses) Gains on Sales and Impairments of Equity Investments in the Consolidated Statement of Operations. Significant sales of other assets and businesses in 2002 are detailed by business segment as follows:

- Natural Gas Transmission's sales of assets totaled $81 million in proceeds. Those sales resulted in gains of $32 million, which were included in (Losses) Gains on Sales and Impairments of Equity Investments in the Consolidated Statements of Operations. Significant sales included a portion of Natural Gas Transmission's limited partnership interests in Northern Border Partners L.P.

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

- *Sales of assets and businesses previously included in Other totaled $133 million in proceeds. Those sales resulted in gains of $32* million, which were included in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statements of Operations. *Significant sales included portions of Duke Engineering & Services, Inc. (DE&S) and DukeSolutions, Inc. (DukeSolutions) businesses,* and the sale of Duke Energy's remaining water operations.

## 3. Business Segments

Duke Energy operates the following business units: Franchised Electric, Natural Gas Transmission, Field Services, DENA, International Energy and Crescent. Duke Energy's chief operating decision maker regularly reviews financial information about each of these business units in deciding how to allocate resources and evaluate performance. The entities under each business unit have similar economic characteristics, services, production processes, distribution methods and regulatory concerns. All of the Duke Energy business units are considered reportable segments under SFAS No. 131.

Franchised Electric generates, transmits, distributes and sells electricity in central and western North Carolina and western South Carolina. It conducts operations through Duke Power. These electric operations are subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the North Carolina Utilities Commission (NCUC) and the PSCSC.

Natural Gas Transmission provides transportation and storage of natural gas for customers along the U.S. East Coast, the Southeast, and in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and natural gas processing services to customers in Western Canada. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission, LLC. Duke Energy Gas Transmission, LLC's natural gas transmission and storage operations in the U.S. are primarily subject to the FERC's and the U.S. Department of Transportation's (DOT's) rules and regulations, while natural gas gathering, processing, transmission, distribution and storage operations in Canada are primarily subject to the rules and regulations of the National Energy Board (NEB) and the Ontario Energy Board (OEB). Texas Eastern Transmission LP (Texas Eastern) is an indirect subsidiary of Natural Gas Transmission and was also a separate Securities and Exchange Commission (SEC) reporting entity. On December 15, 2004 Texas Eastern announced that it filed a Form 15 with the SEC to suspend its reporting obligations under the Securities Exchange Act of 1934. Texas Eastern is eligible to suspend its reporting obligation under the 1934 Act because it has fewer than 300 holders of record of any class of its securities.

Field Services gathers, compresses, treats, processes, transports, trades and markets, and stores natural gas; and fractionates, transports, trades and markets, and stores NGLS. It conducts operations primarily through DEFS, which is approximately 30% owned by ConocoPhillips and approximately 70% owned by Duke Energy. Field Services gathers raw natural gas through gathering systems located in eight major natural gas producing regions: Permian Basin, Mid-Continent, ArklaTex, Gulf Coast, South, Central, Rocky Mountains and Western Canada. DEFS, which previously was a separate SEC reporting entity, announced January 31, 2005 that it filed a Form 15 with the SEC to suspend its reporting obligations under the Securities Exchange Act of 1934. DEFS is eligible to suspend its reporting obligations under the 1934 Act because it has fewer than 300 holders of record of any class of its securities.

In February 2005, Duke Energy executed an agreement with ConocoPhillips whereby Duke Energy has agreed to transfer a 19.7% interest in DEFS to ConocoPhillips for direct and indirect monetary and non-monetary consideration of approximately $1.1 billion. Upon completion of this transaction, DEFS will be owned 50% by Duke Energy and 50% by ConocoPhillips. As a result, Duke Energy expects to account for its investment in DEFS using the equity method subsequent to closing of the transaction. This transaction, which is subject to customary U.S. and Canadian regulatory approvals, is expected to close in the latter half of 2005. Additionally, in February 2005, DEFS sold its wholly-owned subsidiary, Texas Eastern Products Pipeline Company LLC (TEPPCO), the general partner of TEPPCO Partners L.P., for approximately $1.1 billion and Duke Energy sold its limited partner interest in TEPPCO Partners, L.P. for approximately $100 million, in each case to Enterprise GP Holdings L.P. (EPCO), an unrelated third party. TEPPCO Partners L.P. is a publicly traded master limited partnership which owns one of the largest common-carrier pipelines of refined petroleum products and liquefied petroleum gases in the United States, as well as natural gas gathering systems, petrochemical and natural gas liquid pipelines, and is engaged in crude oil transportation, storage, gathering and marketing. TEPPCO is responsible for the management and operations of TEPPCO Partners, L.P.

DENA operates and manages power plants and markets electric power and natural gas related to these plants and other contractual positions. DENA conducts business throughout the U.S. and Canada through Duke Energy North America, LLC and its 100% owned affiliates Duke Energy Marketing America, LLC and Duke Energy Marketing Canada Corp. DENA also participates in DETM. DETM is 40% owned by Exxon Mobil Corporation and 60% owned by Duke Energy.

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**Notes To Consolidated Financial Statements—(Continued)**

International Energy operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U.S. and Canada. It conducts operations primarily through Duke Energy International, LLC (DEI) and its activities target power generation in Latin America. Additionally, International Energy owns an equity investment in National Methanol Company, located in Saudi Arabia, which is a leading regional producer of methanol and methyl tertiary butyl ether (MTBE).

Crescent develops and manages high-quality commercial, residential and multi-family real estate projects primarily in the southeastern and southwestern United States. Some of these projects are developed and managed through joint ventures. Crescent also manages "legacy" land holdings in North and South Carolina.

The remainder of Duke Energy's operations is presented as "Other". While it is not considered a business segment, Other primarily includes certain unallocated corporate costs, DukeNet Communications, LLC (DukeNet), Duke Energy Merchants, LLC (DEM), Bison Insurance Company Limited (BISON), Duke Energy's wholly owned, captive insurance subsidiary and Duke Energy's 50% interest in Duke/Fluor Daniel (D/FD). DukeNet develops, owns and operates a fiber optic communications network, primarily in the Carolinas, serving wireless, local and long-distance communications companies, Internet service providers and other businesses and organizations. During 2003, Duke Energy determined that it would exit the refined products business at DEM in an orderly manner, and continues to unwind its portfolio of contracts. As of December 31, 2004, DEM had exited the majority of its business. Bison's principle activities, as a captive insurance entity, include the insurance and reinsurance of various business risks and losses, such as workers compensation, property, business interruption and general liability of subsidiaries and affiliates of Duke Energy. Bison also participates in reinsurance activities with certain third parties, on a limited basis. D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation. During 2003, Duke Energy and Fluor Corporation announced that they would dissolve the D/FD partnership. The D/FD partners adopted a plan for an orderly wind-down of the business which is expected to be completed by December 2005. Previously, D/FD provided comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide. During 2003, Duke Energy decided to exit the merchant finance business conducted by Duke Capital Partners, LLC (DCP). DCP had been previously included in Other. At December 31, 2004, Duke Energy had exited the merchant finance business, and all of the results of operations for DCP have been classified as discontinued operations in the accompanying Consolidated Statements of Operations.

Duke Energy's reportable segments offer different products and services and are managed separately as business units. Accounting policies for Duke Energy's segments are the same as those described in Note 1. Management evaluates segment performance primarily based on earnings before interest and taxes from continuing operations, after deducting minority interest expense related to those profits (EBIT).

On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. Cash, cash equivalents and short-term investments are managed centrally by Duke Energy, so the associated realized and unrealized gains and losses from foreign currency remeasurement and interest and dividend income on those balances, are excluded from the segments' EBIT.

Transactions between reportable segments are accounted for on the same basis as revenues and expenses in the accompanying Consolidated Financial Statements.

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## Notes To Consolidated Financial Statements—(Continued)

**Business Segment Data**[a]

| | Unaffiliated Revenues | Intersegment Revenues | Total Revenues | Segment EBIT/ Consolidated Earnings (Loss) from Continuing Operations before Income Taxes | Depreciation and Amortization | Capital and Investment Expenditures | Segment Assets[b] |
|---|---|---|---|---|---|---|---|
| | | | | (in millions) | | | |
| **Year Ended December 31, 2004** | | | | | | | |
| Franchised Electric | $ 5,045 | $ 24 | $ 5,069 | $ 1,467 | $ 863 | $1,020 | $18,199 |
| Natural Gas Transmission | 3,117 | 173 | 3,290 | 1,310 | 418 | 533 | 17,106 |
| Field Services | 10,104 | — | 10,104 | 380 | 298 | 213 | 6,810 |
| DENA | 2,228 | 133 | 2,361 | (535) | 173 | 22 | 6,737 |
| International Energy | 619 | — | 619 | 222 | 58 | 28 | 3,329 |
| Crescent[c] | 437 | — | 437 | 240 | 2 | 568 | 1,315 |
| Total reportable segments | 21,550 | 330 | 21,880 | 3,084 | 1,812 | 2,384 | 53,496 |
| Other | 953 | 191 | 1,144 | (77) | 39 | 39 | 1,829 |
| Eliminations | — | (521) | (521) | — | — | — | 145 |
| Interest expense | — | — | — | (1,349) | — | — | — |
| Minority interest expense and other[d] | — | — | — | 114 | — | — | — |
| Total consolidated | $22,503 | $ — | $22,503 | $ 1,772 | $1,851 | $2,423 | $55,470 |
| **Year Ended December 31, 2003** | | | | | | | |
| Franchised Electric | $ 4,854 | $ 21 | $ 4,875 | $ 1,403 | $ 748 | $ 997 | $17,240 |
| Natural Gas Transmission | 2,942 | 255 | 3,197 | 1,317 | 393 | 766 | 16,386 |
| Field Services | 7,921 | 674 | 8,595 | 187 | 293 | 211 | 6,417 |
| DENA | 4,115 | 206 | 4,321 | (3,341) | 251 | 277 | 9,184 |
| International Energy | 597 | — | 597 | 215 | 57 | 71 | 4,550 |
| Crescent[c] | 284 | — | 284 | 134 | 6 | 290 | 1,653 |
| Total reportable segments | 20,713 | 1,156 | 21,869 | (85) | 1,748 | 2,612 | 55,430 |
| Other | 1,367 | 261 | 1,628 | (272) | 44 | (21) | 2,585 |
| Eliminations | — | (1,417) | (1,417) | — | — | — | (790) |
| Interest expense | — | — | — | (1,380) | — | — | — |
| Minority interest expense and other[d] | — | — | — | 27 | — | — | — |
| Total consolidated | $22,080 | $ — | $22,080 | $(1,710) | $1,792 | $2,591 | $57,225 |
| **Year Ended December 31, 2002** | | | | | | | |
| Franchised Electric | $ 4,880 | $ 8 | $ 4,888 | $ 1,595 | $ 614 | $1,269 | $14,642 |
| Natural Gas Transmission | 2,200 | 264 | 2,464 | 1,161 | 324 | 2,878 | 15,189 |
| Field Services | 4,837 | 1,115 | 5,952 | 148 | 281 | 309 | 6,793 |
| DENA | 2,725 | (1,173) | 1,552 | 169 | 190 | 2,013 | 13,487 |
| International Energy | 737 | 6 | 743 | 102 | 54 | 412 | 5,803 |
| Crescent[c] | 226 | — | 226 | 158 | 8 | 275 | 1,685 |
| Total reportable segments | 15,605 | 220 | 15,825 | 3,333 | 1,471 | 7,156 | 57,599 |
| Other | 133 | 170 | 303 | (368) | 35 | 136 | 3,357 |
| Eliminations and reclassifications | 122 | (390) | (268) | 43 | — | — | (834) |
| Interest expense | — | — | — | (1,097) | — | — | — |
| Minority interest expense and other[d] | — | — | — | (5) | — | — | — |
| Cash acquired in acquisitions | — | — | — | — | — | (77) | — |
| Total consolidated | $15,860 | $ — | $15,860 | $ 1,906 | $1,506 | $7,215 | $60,122 |

(a) Segment results exclude results of entities classified as discontinued operations
(b) Includes assets held for sale
(c) Capital expenditures for residential properties are included in operating cash flows on the Consolidated Statement of Cash Flows. Capital expenditures for commercial and multi-family properties are included in investing cash flows on the Consolidated Statement of Cash Flows.
(d) Includes interest income, foreign currency remeasurement gains and losses, and additional minority interest expense not allocated to the segment results.

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**Notes To Consolidated Financial Statements—(Continued)**

**Geographic Data**

| | U.S. | Canada | Latin America | Other Foreign | Consolidated |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| **2004** | | | | | |
| Consolidated revenues | $20,198 | $1,637 | $ 612 | $ 56 | $22,503 |
| Consolidated long-lived assets | 34,938 | 9,863 | 2,399 | 299 | 47,499 |
| **2003** | | | | | |
| Consolidated revenues | $16,507 | $4,890 | $ 556 | $ 127 | $22,080 |
| Consolidated long-lived assets | 36,240 | 9,272 | 2,449 | 1,589 | 49,550 |
| **2002** | | | | | |
| Consolidated revenues | $13,812 | $1,308 | $ 674 | $ 66 | $15,860 |
| Consolidated long-lived assets | 38,138 | 7,895 | 2,118 | 2,234 | 50,385 |

## 4. Regulatory Matters

**Regulatory Assets and Liabilities.** Duke Energy's regulated operations are subject to SFAS No. 71. Accordingly, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. (For further information see Note 1.)

### Duke Energy's Regulatory Assets and Liabilities (a):

| | As of December 31, 2004 | 2003 | Recovery/Refund Period Ends |
|---|---|---|---|
| | (in millions) | | |
| *Regulatory Assets* | | | |
| Net regulatory asset related to income taxes[b] | $1,269 | $1,152 | [l] |
| Asset retirement obligation (ARO) costs[c] | 519 | 547 | 2043 |
| Deferred debt expense[d] | 181 | 169 | 2039 |
| Vacation accrual[c] | 73 | 70 | 2005 |
| U.S. Department of Energy (DOE) assessment fee[c] | 23 | 33 | 2007 |
| Demand-side management costs[d][e] | — | 18 | [m] |
| Project costs[c][d] | 16 | 17 | 2024 |
| Hedge costs and other deferrals[c] | 10 | 2 | 2005 |
| Under-recovery of fuel costs[i] | 9 | — | 2006 |
| Environmental cleanup costs[c] | 8 | 8 | 2017 |
| Total Regulatory Assets | $2,108 | $2,016 | |
| *Regulatory Liabilities* | | | |
| Removal costs[d][g][h] | $ 982 | $1,207 | [n] |
| North Carolina clean air compliance[d][g] | 199 | 95 | 2011 |
| Other deferred tax credits[d][g] | 164 | 160 | [o] |
| Nuclear property and liability reserves[d][g] | 162 | 157 | 2043 |
| Purchased capacity costs (For further information see Note 5.)[d][j] | 135 | 43 | [p] |
| Pipeline rate credit[g] | 38 | 40 | 2041 |
| Over-recovery of fuel costs[f] | — | 30 | 2005 |
| South Carolina rate decrement[k] | — | 23 | 2004 |
| Gas purchase costs[f] | 32 | 14 | 2005 |
| Storage and transportation liability[f] | 16 | 9 | 2005 |
| Earnings sharing liability[f] | 11 | 10 | 2005 |
| Demand-side management costs[d][e] | 5 | — | [m] |
| Total Regulatory Liabilities | $1,744 | $1,788 | |

DUKE ENERGY CORPORATION

**Notes To Consolidated Financial Statements—(Continued)**

(a) All regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) Natural Gas Transmission's amounts are expected to be included in future rate filing, $893 million at December 31, 2004 and $772 million at December 31, 2003. Franchised Electric's amounts are included in rate base, $376 million at December 31, 2004 and $380 million at December 31, 2003.
(c) Included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets
(d) Included in rate base, earns a return
(e) In 2004 included in Other Regulatory Assets and Deferred Debits and Other Deferred Credits and Other Liabilities and in 2003 included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets
(f) Included in Accounts Payable on the Consolidated Balance Sheets
(g) Included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets
(h) In 2004 Duke Energy contributed $262 million in cash to the nuclear decommissioning trust fund for its non-legally obligated nuclear decommissioning costs related to plant components not subject to radioactive contamination. In 2003 these costs were internally reserved as removal costs and classified as a regulatory liability. (For further information see Note 7.)
(i) Included in Receivables on the Consolidated Balance Sheets
(j) In 2004 included in Other Current Liabilities and Other Deferred Credits and Other Liabilities and in 2003 included in Other Current Assets, Other Regulatory Assets and Deferred Debits, Other Current Liabilities, and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets
(k) Included in Other Current Liabilities on the Consolidated Balance Sheets
(l) Recovery/refund is over the life of the associated asset or liability
(m) Incurred costs were deferred and are being recovered in rates. Franchised Electric is currently over-recovered for these costs. Refund period is dependent on volume of sales and cost incurrence.
(n) Refund is over the lives of the associated assets
(o) Duke Power is seeking approval from the NCUC to credit approximately $100 million for previously recorded excess deferred tax liabilities against fuel rates effective July 1, 2005. *(For further information see Note 23.)*
(p) Incurred costs were deferred and are being recovered in rates. Franchised Electric is currently over-recovered for these costs and is refunding the liability through retail rates. Refund period will be determined by the volume of sales.

**Spent Nuclear Fuel.** Under provisions of the Nuclear Waste Policy Act of 1982, Duke Energy contracted with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting spent nuclear fuel on January 31, 1998, the date specified by the Nuclear Waste Policy Act and in Duke Energy's contract with the DOE. In 1998, Duke Energy filed a claim with the U.S. Court of Federal Claims against the DOE related to the DOE's failure to accept commercial spent nuclear fuel by the required date. Damages claimed in the lawsuit are based upon Duke Energy's costs incurred as a result of the DOE's partial material breach of its contract, including the cost of securing additional spent fuel storage capacity. Duke Energy will continue to safely manage its spent nuclear fuel until the DOE accepts it. Payments made to the DOE for disposal costs are based on nuclear output and are included in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power.

**FERC Audits of Pre-Order 2004 Standards of Conduct.** In July 2003, the FERC initiated a public audit of compliance with the pre-Order 2004 standards of conduct by Duke Power as an electric transmission provider and its wholesale merchant function and affiliates. Additionally, in September 2003, the FERC initiated a public audit of compliance with the pre-Order 2004 standards of conduct by Texas Eastern.

The Duke Power audit was closed by the FERC on January 21, 2005. The FERC approved and directed several actions that Duke Power had proposed and implemented to address FERC concerns about full compliance. No penalties were proposed or recommended by the FERC.

On February 28, 2005, the FERC approved a settlement agreement with regard to the Texas Eastern audit. The agreement includes a settlement payment of $500 thousand by Texas Eastern and a compliance plan under which Texas Eastern and its marketing affiliates will adopt certain new procedures.

The FERC's findings have no material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

**Franchised Electric.** *Rate Related Information.* The NCUC and the PSCSC approve rates for retail electric sales within their states. The FERC approves Franchised Electric's rates for electric sales to regulated wholesale customers.

Franchised Electric had recorded approximately $1.4 billion of regulatory assets and $1.9 billion of regulatory liabilities as of December 31, 2004 and December 31, 2003. Management estimates that current rates are sufficient to recover the recorded regulatory assets, in addition to providing a reasonable return for shareholders. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes, recent rate orders to other regulated entities, and the status of any pending or potential deregulation legislation. This assessment reflects the current political and regulatory climate in the states in which Franchised Electric operates, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs would be required to be recognized in operating income. The majority of these regulatory assets, including deferred debt expense and the regulatory asset related to income taxes, are amortized and recovered over the lives of the related assets/debt instruments.

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

Fuel costs are reviewed semiannually by the FERC. The NCUC and PSCSC review fuel costs in rates annually and during general rate case proceedings. All jurisdictions allow Franchised Electric to adjust electric rates for past over- or under-recovery of fuel costs. The difference between actual fuel costs incurred for electric operations and fuel costs recovered through rates is reflected in revenues.

In September 2004, the PSCSC approved Duke Power's proposal for a rate reduction that will lower industrial customers' electric rates by an average of 2.8 percent for one year beginning October 1, 2004. The rate reduction builds on Duke Power's efforts to assist the industrial sector in its South Carolina service area by providing financial relief on monthly power bills. Also, the one year rate decrement approved by the PSCSC for all Duke Power retail electric customers in South Carolina effective October 1, 2003, expired on September 30, 2004.

In 2002, the state of North Carolina passed clean air legislation that freezes electric utility rates from June 20, 2002 to December 31, 2007 (rate freeze period), subject to certain conditions, in order for North Carolina electric utilities, including Duke Energy, to significantly reduce emissions of sulfur dioxide and nitrogen oxides from coal-fired power plants in the state over the next ten years. The legislation allows electric utilities, including Duke Energy, to accelerate the recovery of compliance costs by amortizing them over seven years (2003-2009). Franchised Electric's amortization expense related to this clean air legislation totals $326 million from inception, with $211 million recorded in 2004 and $115 million recorded in 2003. As of December 31, 2004, cumulative expenditures totaled $127 million, with $107 million incurred in 2004 and $20 million incurred in 2003, and are included in Net Cash Provided by Operating Activities on the Consolidated Statements of Cash Flows. The legislation provides for significant flexibility in the amount of annual amortization recorded, allowing utilities to vary the amount amortized, within limits, although the legislation does require that a minimum of 70% of the total estimated cost of $1.5 billion be amortized within the rate freeze period.

*Bulk Power Marketing Profit Sharing.* In June 2004, the NCUC approved Duke Energy's proposal to share 50% of the North Carolina retail allocation of the profits from certain wholesale sales of bulk power from Duke Power generating units at market based rates (BPM Profits). Duke Energy also informed the NCUC that it would no longer include BPM Profits in calculating its North Carolina retail jurisdictional rate of return for its quarterly reports to the NCUC. As approved by the NCUC, the sharing arrangement provides for 50% of the North Carolina allocation of BPM Profits to be distributed through various public assistance programs, up to a maximum of $5 million per year. Any amounts exceeding the maximum will be used to reduce rates for industrial customers in North Carolina.

In June 2004, Duke Energy informed the PSCSC that it would no longer include BPM Profits in calculating its South Carolina retail jurisdictional rate of return for its quarterly reports to the PSCSC. Duke Energy has since established an unconsolidated entity, Advance SC LLC, a South Carolina limited liability company, to receive 50% of the South Carolina retail allocation of the BPM Profits to be distributed through various public assistance programs, and to support certain education programs that promote economic development, and programs to promote the attraction and retention of industrial customers in Duke Power's South Carolina service area. Advance SC LLC is managed by a board of directors that will act independently of Duke Energy. The board consists of representatives from Duke Power's service area, including representatives from industrial customers, educational institutions, governmental and economic development agencies, and Duke Energy. The PSCSC has not addressed the proposed change in reporting BPM Profits. Duke Energy's sharing proposal does not require PSCSC approval.

The sharing agreement in both states applies to BPM Profits from January 1, 2004 until the earlier of December 31, 2007, or the effective date of any rates approved by the respective commission after a general rate case. Profits that have been or that will be shared (Shared Profits) of $32 million have been recorded in 2004. The Shared Profits were booked as an $18 million decrease to revenues (for the portion related to reduced industrial customers rates) and a $14 million charge to expenses (for the portion related to donations to charitable, educational and economic development programs in North Carolina and South Carolina).

*Depreciation and Decommissioning Studies.* The operating licenses for Duke Energy's nuclear units are subject to renewal. In December 2003, Duke Energy was granted renewed operating licenses for the Catawba and McGuire Nuclear Stations until 2041 and 2043 (license expirations vary by nuclear unit). In 2000, Duke Energy was granted renewed operating licenses for the Oconee Nuclear Station until 2033 and 2034 (license expirations vary by nuclear unit).

In March 2005, Duke Power filed the results of a depreciation rate study with the NCUC and PSCSC. Duke Power will adopt new depreciation rates for all functions effective January 1, 2005. The study indicates application of the new rates to depreciable plant in service as of January 1, 2005 will result in an immaterial change in depreciation expense in 2005.

In June 2004 Duke Power filed with the NCUC and PSCSC the results of a 2003 nuclear decommissioning study, which indicate an estimated cost of $2.3 billion (in 2003 dollars) to decommission the nuclear facilities. The previous study, conducted in 1999, estimated

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

a decommissioning cost of $1.9 billion ($2.2 billion in 2003 dollars at 3% inflation). The estimated increase is due primarily to inflation and cost increases for the size of the organization needed to manage the decommissioning project (based on current industry experience at facilities undergoing decommissioning).

In October 2004, Duke Power filed the results of a funding study for nuclear decommissioning costs with the NCUC and in December 2004, Duke Power notified the PSCSC of the results of the funding study. (For further information see Note 7.)

*Regional Transmission Organizations (RTOs).* The FERC continues to advocate for independent functioning of transmission grids, including through a variety of rulemakings and policy proposals, and has supported the development of Regional Transmission Organizations (RTOs) across the U.S. As a result of these rulemakings, Duke Power and the franchised electric units of Carolina Power & Light Company (now Progress Energy Carolinas) and South Carolina Electric & Gas Company, planned to establish GridSouth Transco, LLC (GridSouth), as an RTO responsible for the functional control of the companies' combined transmission systems. As of December 31, 2004 and 2003, Duke Energy had invested $41 million in GridSouth, including carrying costs calculated through December 31, 2002. This amount is included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets. Due to regulatory uncertainty, development of the GridSouth implementation project was suspended in 2002. Duke Energy continues to examine options in support of FERC's transmission policy goals. Management expects it will recover its investment in GridSouth.

**Natural Gas Transmission.** *Rate Related Information.* The British Columbia Pipeline System (BC Pipeline) and the field services business in western Canada recorded regulatory assets related to deferred income tax liabilities of approximately $612 million as of December 31, 2004 and $543 million as of December 31, 2003. Under the current NEB-authorized rate structure, income tax costs are recovered in tolls based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that the transportation and field services tolls will be adjusted to recover these taxes. Since most of these timing differences are related to property, plant and equipment costs, this recovery is expected to occur over a 20 to 30 year period.

When evaluating the recoverability of the BC Pipeline and the field services' regulatory assets, management takes into consideration the NEB regulatory environment, natural gas reserve estimates for reserves located, or expected to be located, near these assets, the ability to remain competitive in the markets served, and projected demand growth estimates for the areas served by BC Pipeline and the field services business. Based on current evaluation of these factors, management believes that recovery of these tax costs is probable over the periods described above.

In November 2004, the NEB approved 2005 interim tolls for BC Pipeline to be effective January 1, 2005. BC Pipeline will file an application with the NEB for approval of final 2005 tolls under the 2004 settlement agreement in the first quarter of 2005.

Union Gas Limited (Union Gas) has rates that are approved by the OEB. Rates for the sale of gas are adjusted quarterly to reflect updated commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery from or return to customers, subject to approval by the OEB. These differences are directly flowed through to customers and, therefore, no rate of return is earned on the related deferred balances. The OEB's review and approval of these gas purchase costs primarily considers the prudence of the costs incurred.

On December 15, 2004 the OEB approved the 2005 rates for Union Gas. The OEB also implemented an asymmetrical earnings sharing mechanism for Union Gas, effective January 1, 2005. Earnings in 2005, above the benchmark return on equity (ROE) determined through the OEB's formulaic approach, normalized for weather, will be shared equally between ratepayers and Union Gas. No rate relief will be provided if Union Gas earns below the allowed ROE. Union Gas filed a Notice of Motion on December 22, 2004 to have the OEB reconsider its decision.

The OEB has proposed changes to the implementation dates for the Gas Distribution Access Rule (GDAR). GDAR provides the means by which gas vendors access gas distribution systems in Ontario. Union Gas was granted leave to appeal the vendor consolidated billing provisions of GDAR by the Court of Appeal for Ontario. On January 11, 2005, the Court of Appeal for Ontario dismissed the appeal. The OEB has proposed to defer the implementation of specific sections of the GDAR and to exempt gas distributors from the vendor consolidated billing provisions of the GDAR, subject to any person applying for the OEB to end the exemption.

Maritimes & Northeast Pipeline L.L.C. filed a rate case with the FERC on June 30, 2004 seeking an increase in rates from $0.695 per dekatherm (Dth) to $1.07/Dth. A FERC order accepted the rate filing and suspended the rates until January 1, 2005, when they became effective, subject to refund. The rate case has been set for hearing in 2005. Settlement discussions are ongoing.

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**Notes To Consolidated Financial Statements—(Continued)**

Management believes that the effects of these matters will have no material adverse effect on Duke Energy's future consolidated results of operations, cash flows or financial position.

**International Energy.** *Brazil Regulatory Environment.* In 2004, a new energy law was enacted in Brazil that changed the electricity sector's regulatory framework. The new energy law created a regulated and non-regulated market that will coexist. The regulated market consists of auctions conducted by the government for the sale of power to the distribution companies. The distribution companies are required to fully contract their estimated electricity demand, principally through these regulated auctions. In the non-regulated market, generators, traders and non-regulated customers are permitted to enter into bilateral electricity purchase and sale contracts. The first regulated auction was held on December 7, 2004. In this auction, distribution companies contracted for their estimated demand for the period from 2005 to 2014. The contract structure within the auction process consisted of eight-year contracts with delivery periods commencing in each of the years 2005, 2006 and 2007. Duke Energy's Brazilian affiliate, Duke Energy International, Geracao Paranapanema S.A., participated in this auction as a seller of electricity and was awarded eight-year contracts for delivery of 214 MW beginning in 2005, 58 MW for delivery beginning in 2006, and 218 megawatts (MW) for delivery beginning in 2007. During 2005, Duke Energy's Brazilian affiliate may participate in the next regulated auction for the sale of power to the distribution companies. The auction process provides for eight year contracts with delivery commencing in 2008 and 2009.

## 5. Joint Ownership of Generating Facilities

**Joint Ownership of Catawba Nuclear Station[a]**

| Owner | Ownership Interest |
|---|---|
| North Carolina Municipal Power Agency Number 1 | 37.5% |
| North Carolina Electric Membership Corporation | 28.1% |
| **Duke Energy Corporation** | **12.5%** |
| Piedmont Municipal Power Agency | 12.5% |
| Saluda River Electric Cooperative, Inc. | 9.4% |
| | 100.0% |

(a) Facility operated by Duke Energy

As of December 31, 2004, $561 million of property, plant and equipment and $295 million of accumulated depreciation and amortization represented Duke Energy's undivided interest in Catawba Nuclear Station Units 1 and 2. Duke Energy's share of revenues and operating costs is included in the Consolidated Statements of Operations. As of December 31, 2003, $564 million of property, plant and equipment and $291 million of accumulated depreciation and amortization represented Duke Energy's undivided interest in Catawba Nuclear Station Units 1 and 2.

Contractual agreements to purchase declining percentages of the station's generating capacity and energy through the year 2000 made purchased capacity costs subject to rate levelization and deferral. For the North Carolina jurisdiction, all deferred costs were fully recovered as of June 30, 2004. The cost of capacity purchased but not reflected in rates for the North Carolina jurisdiction was $103 million as of December 31, 2003 and was included in Other Current Assets and Other Regulatory Assets and Deferred Debits on the December 31, 2003 Consolidated Balance Sheet. In the South Carolina rate jurisdiction, Duke Energy is currently overcollected on purchased capacity costs. The amount of the overcollection is included in Other Current Liabilities and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets. The liability related to the South Carolina jurisdiction was $135 million as of December 31, 2004 and $146 million as of December 31, 2003. Duke Energy is currently reducing the liability amounts annually through a rate decrement.

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

## 6. Income Taxes

The following details the components of income tax expense (benefit) from continuing operations:

**Income Tax Expense (Benefit) from Continuing Operations**

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (in millions) | | |
| Current income taxes | | | |
| Federal | $(405) | $(217) | $ 84 |
| State | 28 | (76) | 14 |
| Foreign | 83 | 127 | 18 |
| Total current income taxes | (294) | (166) | 116 |
| Deferred income taxes | | | |
| Federal | 868 | (486) | 440 |
| State | (71) | (9) | 21 |
| Foreign | 48 | (33) | 48 |
| Total deferred income taxes | 845 | (528) | 509 |
| *Investment tax credit amortization* | (11) | (13) | (14) |
| Total income tax expense (benefit) from continuing operations | $ 540 | $(707)[a] | $611 |

(a) Excludes $94 million of deferred federal, state and foreign tax benefits related to the cumulative effect of changes in accounting principles recorded net of tax.

The taxes recorded for discontinued operations are excluded from the continuing operations section above and are presented as a separate column in Note 13.

**Earnings (Loss) from Continuing Operations before Income Taxes**

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (in millions) | | |
| Domestic | $1,295 | $(2,005) | $1,619 |
| Foreign | 477 | 295 | 287 |
| Total income (loss) | $1,772 | $(1,710) | $1,906 |

**Reconciliation of Income Tax Expense (Benefit) at the US Federal Statutory Tax Rate to the Actual Tax Expense (Benefit) from Continuing Operations (Statutory Rate Reconciliation)**

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (in millions) | | |
| Income tax expense (benefit), computed at the statutory rate of 35% | $ 620 | $(599) | $ 667 |
| State income tax, net of federal income tax effect | (28) | (55) | 23 |
| Tax differential on foreign earnings | (35) | (9) | (34) |
| Employee stock ownership plan dividends | (19) | (20) | (33) |
| US tax on repatriation of foreign earnings | 36 | — | — |
| Other items, net | (34) | (24) | (12) |
| Total income tax expense (benefit) from continuing operations | $ 540 | $(707) | $ 611 |
| Effective tax rate | 30.5% | 41.3% | 32.1% |

DUKE ENERGY CORPORATION

**Notes To Consolidated Financial Statements—(Continued)**

During 2004, Duke Energy recorded a $52 million income tax benefit from the reduction of state and federal income tax reserves based on the resolution in the second quarter of 2004 of several tax issues. The $52 million benefit is included in the Statutory Rate Reconciliation as follows: a $39 million state benefit is included in "State income tax, net of federal income tax effect" and a $13 million federal benefit is included in "Other items, net".

During 2004, Duke Energy recorded a $48 million income tax benefit from the change in state tax rates relating to deferred taxes as a result of a reorganization of certain subsidiaries. The $48 million benefit is included in "State income tax, net of federal income tax effect" in the Statutory Rate Reconciliation.

During 2004, Duke Energy recorded a $45 million income tax expense for the repatriation of foreign earnings that is anticipated to occur during 2005 related to the American Jobs Creation Act of 2004. The $45 million is included in the Statutory Rate Reconciliation as follows: Federal income taxes of $36 million are included in "US tax on repatriation of foreign earnings", $4 million of state taxes are included in "State income tax, net of federal income tax effect", and $5 million of foreign taxes are included in "Tax differential on foreign earnings".

**Net Deferred Income Tax Liability Components**

| | December 31, | |
|---|---|---|
| | 2004 | 2003 |
| | (in millions) | |
| Deferred credits and other liabilities | $ 1,334 | $ 1,190 |
| Other | 297 | 38 |
| *Total deferred income tax assets* | 1,631 | 1,228 |
| Valuation allowance | (38) | (39) |
| Net deferred income tax assets | 1,593 | 1,189 |
| Investments and other assets | (990) | (985) |
| Accelerated depreciation rates | (4,291) | (3,006) |
| Regulatory assets and deferred debits | (1,167) | (1,059) |
| *Total deferred income tax liabilities* | (6,448) | (5,050) |
| *Total net deferred income tax liabilities* | $(4,855) | $(3,861) |

The above amounts have been classified in the Consolidated Balance Sheets as follows:

**Deferred Tax Liabilities**

| | December 31, | |
|---|---|---|
| | 2004 | 2003 |
| | (in millions) | |
| Current deferred tax assets, included in other current assets | $ 217 | $ 62 |
| Non-current deferred tax assets, included in other investments and other assets | 159 | 197 |
| Current deferred tax liabilities, included in other current liabilities | (3) | — |
| Non-current deferred tax liabilities | (5,228) | (4,120) |
| Total net deferred income tax liabilities | $(4,855) | $(3,861) |

As of December 31, 2004, Duke Energy has a net operating loss carryforwards of $274 million relating to federal income taxes which expire in the year 2024 and $61 million relating to state income taxes which mostly expire in years 2019 and later.

Valuation allowances have been established for certain foreign and state net operating loss carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. The net change in the total valuation allowance is included in "Tax differential on foreign earnings" and "State income tax, net of federal income tax effect" lines of the Statutory Rate Reconciliation.

Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income and other taxes have been made for potential liabilities resulting from such matters. As of December 31, 2004, Duke Energy has total provisions for uncertain

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**Notes To Consolidated Financial Statements—(Continued)**

tax positions of approximately $149 million as compared to $254 million as of December 31, 2003, which includes interest. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

Deferred income taxes and foreign withholding taxes of $45 million have been recorded in the fourth quarter of 2004 on approximately $500 million of earnings relating to Duke Energy's foreign subsidiaries that are anticipated to be remitted in 2005 as dividends relating to the American Jobs Creation Act of 2004. Deferred income taxes and foreign withholding taxes have not been provided on the remaining undistributed earnings of Duke Energy's foreign subsidiaries as such amounts are deemed to be permanently reinvested. The cumulative undistributed earnings as of December 31, 2004 on which Duke Energy has not provided deferred income taxes and foreign withholding taxes, is approximately $150 million.

## 7. Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143 which addresses financial accounting and reporting for legal obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. Asset retirement obligations at Duke Energy relate primarily to the decommissioning of nuclear power facilities, the retirement of certain gathering pipelines and processing facilities, the retirement of some gas-fired power plants, obligations related to right-of-way agreements and contractual leases for land use.

SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled.

In accordance with SFAS No. 143, Duke Energy identified certain assets that have an indeterminate life, and thus a future retirement obligation is not determinable. These assets included on-shore and some off-shore pipelines, certain processing plants and distribution facilities and some gas-fired power plants. A liability for these asset retirement obligations will be recorded when a fair value is determinable.

Upon adoption of SFAS No. 143, Duke Energy's regulated electric and regulated natural gas operations classified removal costs for property that does not have an associated legal retirement obligation as a regulatory liability, in accordance with regulatory treatment. The total amount of removal costs included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets was $982 million as of December 31, 2004, which consisted of $966 million related to regulated electric operations and $16 million related to regulated natural gas operations. The total amount of removal costs included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets was $1,207 million as of December 31, 2003, which consisted of $1,190 million related to regulated electric operations and $17 million related to regulated natural gas operations.

SFAS No. 143 was effective for fiscal years beginning after June 15, 2002, and was adopted by Duke Energy on January 1, 2003. As of January 1, 2003, the implementation of SFAS No. 143 resulted in a net increase in total assets of $863 million, consisting primarily of an increase in net property, plant and equipment of $213 million and an increase in regulatory assets of $650 million. Liabilities increased by $874 million, primarily representing the establishment of an asset retirement obligation liability of $1,599 million, reduced by the amount that was already recorded as a nuclear decommissioning liability of $708 million. Substantially all of the obligations are related to Duke Energy's regulated electric operations. The adoption of SFAS No. 143 had no impact on the income of the regulated electric operations, as the effects were offset by the establishment of a regulatory asset pursuant to SFAS No. 71. Duke Energy has received approval from both the NCUC and PSCSC to defer all cumulative and future income statement impacts related to SFAS No. 143. For obligations related to non-regulated operations, a net-of-tax cumulative effect of a change in accounting principle adjustment of $11 million was recorded in the first quarter of 2003 as a reduction in earnings.

The pro forma net income and related basic and diluted earnings per share effects of adopting SFAS No. 143 are not shown due to their immaterial impact.

The asset retirement obligation is adjusted each period for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

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## Notes To Consolidated Financial Statements—(Continued)

**Reconciliation of Asset Retirement Obligation Liability**

| | Years Ended December 31, | |
|---|---|---|
| | 2004 | 2003 |
| | (in millions) | |
| Balance as of January 1, | $1,707 | $1,599 |
| Liabilities incurred due to new acquisitions | 8 | — |
| Liabilities settled | (2) | (7) |
| Accretion expense | 125 | 111 |
| Revisions in estimated cash flows | 86 | (2) |
| Foreign currency adjustment | 2 | 6 |
| Balance as of December 31, | $1,926 | $1,707 |

Accretion expense for the year ended December 31, 2004 included approximately $120 million related to Duke Energy's regulated electric operations and has been deferred as a regulatory asset in accordance with SFAS No. 71 as discussed above. Accretion expense for the year ended December 31, 2003 included approximately $106 million related to Duke Energy's regulated electric operations and has also been deferred as a regulatory asset in accordance with SFAS No. 71. The fair value of assets legally restricted for the purpose of settling asset retirement obligations associated with nuclear decommissioning was $1,082 million as of December 31, 2004 and $925 million as of December 31, 2003.

Revisions in estimated cash flows changed significantly during 2004 due primarily to the new nuclear decommissioning study performed during the year at Franchised Electric. As a result of that study, it was determined that more nuclear obligations existed and as such, the additional liability was recorded.

**Nuclear Decommissioning Costs.** In 2003, an internal reserve, which is contained in the accumulated depreciation balance on the Consolidated Balance Sheets and external funds, presented on the Consolidated Balance Sheets as the NDTF for decommissioning were maintained separately for contaminated and non-contaminated components. These external funds were invested primarily in domestic and international equity securities, fixed-rate, fixed-income securities and cash and cash equivalents and were recorded at their fair value in the Consolidated Balance Sheets. Per the regulation or mandates of one or more entities including the Nuclear Regulatory Commission (NRC), PSCSC, NCUC, and Internal Revenue Service, these funds may be used only for activities related to nuclear decommissioning. Those investments are exposed to price fluctuations in equity markets and changes in interest rates. Because the accounting for nuclear decommissioning recognizes that costs are recovered through Franchised Electric's rates, fluctuations in equity prices or interest rates do not affect consolidated results of operations or cash flows. (See Note 1, Other Long-term Investments and Note 9 for additional information.)

On February 5, 2004, the NCUC issued an order requiring Duke Energy to transition the internal reserve to the NDTF over a ten-year period, beginning on January 1, 2008, with the annual transfer level at a minimum of 10% of the North Carolina internal reserve as of December 31, 2007, and with the actual transfer of funds occurring no later than December 31 of each calendar year beginning in 2008. The NCUC also ordered that as of December 31, 2007, there shall be no further funding of internal reserve and all future decommissioning requirements must be fully funded through the NDTF.

During 2004, Duke Energy expensed approximately $70 million and contributed approximately $70 million of cash to the NDTF for decommissioning costs; these amounts are presented in the Consolidated Statements of Cash Flows in Other within Cash Flows from Investing Activities. Pursuant to the February 5, 2004 NCUC order in April 2004, $262 million reserved for non-contaminated costs was contributed in cash, to the NDTF; these amounts are also presented in the Consolidated Statements of Cash Flows in Other within Cash Flows from Investing Activities. During 2003, Duke Energy expensed approximately $56 million, and contributed $56 million of cash to the NDTF for decommissioning costs, and accrued an additional $11 million to the internal reserve. Nuclear units are currently depreciated at an annual rate of 4.7%, of which 1.61% is for decommissioning. The balance of the external funds was $1,374 million as of December 31, 2004 and $925 million as of December 31, 2003. These amounts are reflected in the Consolidated Balance Sheets as Nuclear Decommissioning Trust Funds (asset).

In October 2004, Duke Power filed the results of a funding study for nuclear decommissioning costs with the NCUC, and in December 2004, Duke Power notified the PSCSC of the results of the funding study (filing of the study is not required by the PSCSC). The

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**Notes To Consolidated Financial Statements—(Continued)**

funding study, which was based on the updated nuclear decommissioning cost estimate and renewal of the nuclear operating licenses, indicates that an annual cash contribution to the NDTF of $48 million (compared to a current level of approximately $70 million) is now required to fully cover the estimated nuclear decommissioning costs. Duke Power anticipates that the NCUC will rule later in 2005 on whether any change in Duke Power's decommissioning expense is necessary.

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $2.3 billion in 2003 dollars, based on a decommissioning study completed in 2004. This includes costs related to Duke Energy's 12.5% ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. The previous study, conducted in 1999, estimated a decommissioning cost of $1.9 billion ($2.2 billion in 2003 dollars at 3% inflation). The estimated increase is due primarily to inflation and cost increases for the size of the organization needed to manage the decommissioning project (based on current industry experience at facilities undergoing decommissioning). Both the NCUC and the PSCSC have allowed Duke Energy to recover estimated decommissioning costs through retail rates over the expected remaining service periods of Duke Energy's nuclear stations. Management believes that the decommissioning costs being recovered through rates, when coupled with expected fund earnings, are sufficient to provide for the cost of decommissioning.

The operating licenses for Duke Energy's nuclear units are subject to extension. In December 2003, Duke Energy was granted renewed operating licenses for the Catawba and McGuire Nuclear Stations until 2041 and 2043 (license expirations vary by nuclear unit). In 2000, Duke Energy was granted a license renewal for the Oconee Nuclear Station until 2033 and 2034 (license expirations vary by nuclear unit).

**Current Operating Licenses for Duke Energy's Nuclear Units**

| Unit | Expiration Year |
|---|---|
| McGuire 1 | 2041 |
| McGuire 2 | 2043 |
| Catawba 1 | 2043 |
| Catawba 2 | 2043 |
| Oconee 1 and 2 | 2033 |
| Oconee 3 | 2034 |

To reflect the impact on the nuclear decommissioning asset retirement obligation resulting from the renewed operating licenses and the change in estimated decommissioning costs, the asset retirement obligation was increased by $109 million in 2004. Additionally, due in part to the renewal of the nuclear operating licenses, Franchised Electric conducted a depreciation rate study. In March 2005, Duke Power filed the results of a depreciation rate study with the NCUC and PSCSC. Duke Power adopted new depreciation rates for all functions effective January 1, 2005. The study indicates application of the new rates to depreciable plant in service as of January 1, 2005 will result in an immaterial change in depreciation expense in 2005.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants (the D&D Fund). Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. Lawsuits filed by Duke Energy and other utilities challenging the constitutionality of the D&D Fund have been dismissed. The annual assessment is recorded in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power. Duke Energy has paid $129 million into the fund, including $11 million each year during 2004, 2003 and 2002. The remaining liability and regulatory assets of $23 million as of December 31, 2004 and $33 million as of December 31, 2003 are reflected in the Consolidated Balance Sheets as Deferred Credits and Other Liabilities, and Regulatory Assets and Deferred Debits.

## 8. Risk Management and Hedging Activities, Credit Risk, and Financial Instruments

Duke Energy is exposed to the impact of market fluctuations in the prices of natural gas, electricity and other energy-related products marketed and purchased as a result of its ownership of energy related assets, interests in structured contracts and remaining proprietary trading activities. Exposure to interest rate risk exists as a result of the issuance of variable and fixed rate debt and commercial paper. Duke Energy is exposed to foreign currency risk from investments in international affiliate businesses owned and operated in foreign countries and from certain commodity-related transactions within domestic operations. Duke Energy employs established policies

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**Notes To Consolidated Financial Statements—(Continued)**

and procedures to manage its risks associated with these market fluctuations using various commodity and financial derivative instruments, including forward contracts, futures, swaps, options and swaptions.

**Duke Energy's Derivative Portfolio Carrying Value as of December 31, 2004**

| Asset/(Liability) | Maturity in 2005 | Maturity in 2006 | Maturity in 2007 | Maturity in 2008 and Thereafter | Total Carrying Value |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| Hedging | $167 | $294 | $167 | $ 173 | $ 801 |
| Trading | 47 | 21 | (5) | (9) | 54 |
| Undesignated | (71) | (52) | (49) | (132) | (304) |
| Total | $143 | $263 | $113 | $ 32 | $ 551 |

The amounts in the table above represent the combination of amounts presented as assets and (liabilities) for Unrealized Gains and Losses on Mark-to-Market and Hedging Transactions on Duke Energy's Consolidated Balance Sheets. All amounts in the table represent fair value except that certain hedging amounts include assets related to the application of the normal purchases and normal sales exception for electricity contracts of $160 million as of December 31, 2004. Duke Energy began applying the normal purchases and normal sales exception of DIG Issue C15 for electricity contracts July 1, 2001. For those contracts that were previously designated as cash flow hedges, Duke Energy treated the change as a de-designation under SFAS No. 133, and the fair value of each qualifying contract on July 1, 2001 became the contract's net carrying amount. The contract's net carrying amount will reduce upon settlement of the associated contracts over the next six years.

**Commodity Cash Flow Hedges.** Some Duke Energy subsidiaries are exposed to market fluctuations in the prices of various commodities related to their ongoing power generating and natural gas gathering, distribution, processing and marketing activities. Duke Energy closely monitors the potential impacts of commodity price changes and, where appropriate, enters into contracts to protect margins for a portion of future sales and generation revenues and fuel expenses. Duke Energy uses commodity instruments, such as swaps, futures, forwards and options, as cash flow hedges for natural gas, electricity and natural gas liquid transactions. Duke Energy is hedging exposures to the price variability of these commodities for a maximum of 13 years.

The ineffective portion of commodity cash flow hedges resulted in a gain of $3 million in 2004, a gain of $7 million in 2003, and a loss of $10 million in 2002, pre-tax, and is reported in the Non-Regulated Electric, Natural Gas, Natural Gas Liquids and Other line item on the Consolidated Statement of Operations. The amount recognized for transactions that no longer qualified as cash flow hedges was not material in 2004 or 2002 and was a gain of $285 million in 2003, pre-tax. The 2003 disqualified cash flow hedges were primarily associated with gas hedges related to DENA's Southeast Plants and partially completed plants.

As of December 31, 2004, $311 million of the pre-tax deferred net gains on derivative instruments related to commodity cash flow hedges that were accumulated on the Consolidated Balance Sheet in a separate component of stockholders' equity, in AOCI, and are expected to be recognized in earnings during the next 12 months as the hedged transactions occur. However, due to the volatility of the commodities markets, the corresponding value in AOCI will likely change prior to its reclassification into earnings.

**Commodity Fair Value Hedges.** Some Duke Energy subsidiaries are exposed to changes in the fair value of some unrecognized firm commitments to sell generated power or natural gas due to market fluctuations in the underlying commodity prices. Duke Energy actively evaluates changes in the fair value of such unrecognized firm commitments due to commodity price changes and, where appropriate, uses various instruments to hedge its market risk. These commodity instruments, such as swaps, futures and forwards, serve as fair value hedges for the firm commitments associated with generated power. For 2004, 2003, and 2002 the ineffective portion of commodity fair value hedges was reported in the Non-Regulated Electric, Natural Gas, Natural Gas Liquids, and Other line item on the Consolidated Statement of Operations and was not material. The amount recognized for transactions that no longer qualified as hedged firm commitments was not material in 2004 or 2002 and was a loss of $582 million, pre-tax, in 2003. The loss recorded in 2003, which primarily included amounts for certain contracts that were being accounted for as normal purchases and sales, was recognized due to management's intent for DENA's Southeast Plants and partially completed plants.

**Normal Purchases and Normal Sales Exception.** Duke Energy has applied the normal purchases and normal sales scope exception, as provided in SFAS No. 133 and interpreted by DIG Issue C15, to certain contracts involving the purchase and sale of electricity at fixed prices in future periods. These contracts, which relate primarily to the delivery of electricity over the next 11 years, are not included in the table above. As discussed in the preceding paragraph, a portion of the charge in DENA in 2003 related to contracts that were being accounted for as normal purchases and sales.

**Interest Rate (Fair Value or Cash Flow) Hedges.** Changes in interest rates expose Duke Energy to risk as a result of its issuance of variable-rate debt and commercial paper. Duke Energy manages its interest rate exposure by limiting its variable-rate and fixed-rate exposures to percentages of total capitalization and by monitoring the effects of market changes in interest rates. Duke Energy also enters into financial derivative instruments, including, but not limited to, interest rate swaps, swaptions and U.S. Treasury lock agreements to manage and mitigate interest rate risk exposure. Duke Energy's existing interest rate derivative instruments and related ineffectiveness were not material to its consolidated results of operations, cash flows or financial position in 2004, 2003, and 2002.

**Foreign Currency (Fair Value, Net Investment or Cash Flow) Hedges.** Duke Energy is exposed to foreign currency risk from investments in international affiliate businesses owned and operated in foreign countries and from certain commodity-related transactions within domestic operations. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, or investments may be hedged through debt denominated or issued in the foreign currency. Duke Energy may also use foreign currency derivatives, where possible, to manage its risk related to foreign currency fluctuations. During 2004, $43 million of net losses were included in the cumulative translation adjustment for hedges of net investments in foreign operations. During 2003, a $113 million net loss was included in the cumulative translation adjustment for hedges of net investments in foreign operations. During 2002, a $4 million net loss was included in the cumulative translation adjustment for hedges of net investments in foreign operations. To monitor its currency exchange rate risks, Duke Energy uses sensitivity analysis, which measures the impact of devaluation of foreign currencies.

**Other Derivative Contracts.** *Trading.* Duke Energy is exposed to the impact of market fluctuations in the prices of natural gas, electricity and other energy-related products marketed and purchased as a result of proprietary trading activities. During 2003, Duke Energy prospectively discontinued proprietary trading and therefore the fair value of trading contracts as of December 31, 2004 relates to contracts entered into prior to the announced discontinuation of proprietary trading activities. Duke Energy's exposure to commodity price risk is influenced by a number of factors, including contract size, length, market liquidity, location and unique or specific contract terms.

*Undesignated.* In addition, Duke Energy uses derivative contracts to manage the market risk exposures that arise from energy supply, structured origination, marketing, risk management, and commercial optimization services to large energy customers, energy aggregators and other wholesale companies, and to manage interest rate and foreign currency exposures. This category includes changes in fair value for derivatives that no longer qualify for the normal purchase and normal sales scope exception and disqualified hedge contracts, unless the derivative contract is subsequently re-designated as a hedge. The contracts in this category are primarily associated with forward power sales for the DENA Southeast Plants and partially completed plants which were disqualified in 2003.

**Credit Risk.** Duke Energy's principal customers for power and natural gas marketing and transportation services are industrial end-users, marketers, local distribution companies and utilities located throughout the U.S., Canada and Latin America. Duke Energy has concentrations of receivables from natural gas and electric utilities and their affiliates, as well as industrial customers and marketers throughout these regions. These concentrations of customers may affect Duke Energy's overall credit risk in that risk factors can negatively impact the credit quality of the entire sector. Where exposed to credit risk, Duke Energy analyzes the counterparties' financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of those limits on an ongoing basis.

Duke Energy's industry has historically operated under negotiated credit lines for physical delivery contracts. Duke Energy frequently uses master collateral agreements to mitigate certain credit exposures, primarily in its trading and marketing and risk management operations. The collateral agreements provide for a counterparty to post cash or letters of credit to the exposed party for exposure in excess of an established threshold. The threshold amount represents an unsecured credit limit, determined in accordance with the corporate credit policy. Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions.

Collateral amounts held or posted may be fixed or may vary depending on the terms of the collateral agreement and the nature of the underlying exposure and generally covers trading, normal purchases and normal sales, and hedging contracts outstanding. Duke Energy may be required to return certain held collateral and post additional collateral should price movements adversely impact the value

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**Notes To Consolidated Financial Statements—(Continued)**

of open contracts or positions. In many cases, Duke Energy's and its counterparties' publicly disclosed credit ratings impact the amounts of additional collateral to be posted. Likewise, downgrades in credit ratings of counterparties could require counterparties to post additional collateral to Duke Energy and its affiliates.

The change in market value of New York Mercantile Exchange (NYMEX)-traded futures and options contracts requires daily cash settlement in margin accounts with brokers.

Duke Energy also obtains cash or letters of credit from customers to provide credit support outside of collateral agreements, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

**Financial Instruments.** The fair value of financial instruments not currently carried at market value is summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 2004 and 2003, are not necessarily indicative of the amounts Duke Energy could have realized in current markets.

**Financial Instruments**

| | Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2004 | | 2003 | |
| | Book Value | Approximate Fair Value | Book Value | Approximate Fair Value |
| | (in millions) | | | |
| Long-term debt[a] | $18,764 | $20,448 | $21,822 | $23,554 |
| Preferred stock | 134 | 133 | 134 | 135 |

(a) Includes current maturities.

The fair value of cash and cash equivalents, notes and accounts receivable, notes and accounts payable and commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

## 9. Marketable Securities

*Short-term investments.* At December 31, 2004 and 2003 Duke Energy had $1,319 million and $763 million, respectively of short-term investments consisting primarily of highly liquid tax-exempt debt securities. These instruments are classified as available-for-sale securities under SFAS No. 115 as management does not intend to hold them to maturity nor are they bought and sold with the objective of generating profits on short-term differences in price. The carrying value of these instruments approximates their fair value as they contain floating rates of interest. During 2004, Duke Energy purchased approximately $63,879 million and received proceeds on sale of approximately $63,323 million of short-term investments. During 2003, Duke Energy purchased approximately $38,908 million and received proceeds on sale of approximately $38,638 million of short-term investments. During 2002, Duke Energy purchased approximately $11,920 million and received proceeds on sale of approximately $11,427 million.

*Other Long-term investments.* Duke Energy also invests in debt and equity securities that are held in the NDTF (see Note 4 for further information on the nuclear decommissioning trust funds) and the captive insurance investment portfolio that are classified as available-for-sale under SFAS No. 115 and therefore are carried at estimated fair value based on quoted market prices. These investments are classified long-term as management does not intend to use them in current operations. Duke Energy's NDTF ($1,374 million at December 31, 2004) consists of approximately of 68% equity securities, 30% debt securities, and 2% cash and cash equivalents with a weighted average maturity of the debt securities of approximately 8 years. Duke Energy's captive insurance investment portfolio ($185 million at December 31, 2004) consists of approximately 66% debt securities, 21% cash and cash equivalent and 13% equity securities with a weighted average maturity of the debt securities of approximately 8 years. The cost of securities sold is determined using the specific identification method.

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**Notes To Consolidated Financial Statements—(Continued)**

The estimated fair values of long-term investments classified as available-for-sale are as follows (in millions):

| | As of December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2004 | | | 2003 | | |
| | Gross Unrealized Holding Gains | Gross Unrealized Holding Losses | Estimated Fair Value | Gross Unrealized Holding Gains | Gross Unrealized Holding Losses | Estimated Fair Value |
| Equity Securities | $261 | $17 | $ 960 | $181 | $20 | $ 657 |
| Corporate Debt Securities | 1 | — | 40 | 1 | — | 50 |
| Municipal Bonds | 3 | — | 193 | 4 | — | 66 |
| U.S. Government Bonds | 14 | 1 | 252 | 13 | — | 266 |
| Other | 1 | — | 114 | 1 | — | 122 |
| Total | $280 | $18 | $1,559 | $200 | $20 | $1,161 |

For the years ended December 31, 2004, 2003, and 2002 gains of approximately $3 million, $4 million and $4 million, respectively, were reclassified out of AOCI into earnings.

The following table provides the realized gains and losses, as well as gross proceeds from sale and gross purchases of the captive insurance investment portfolio (in millions):

| Years Ended December 31, | 2004 | 2003 | 2002 |
|---|---|---|---|
| Realized Gains | $ 6 | $ 9 | $ 4 |
| Realized Losses | 3 | 5 | 3 |
| Proceeds from sale of securities | 769 | 1,003 | 432 |
| Purchases of securities | 715 | 1,124 | 473 |

Duke Energy contributed approximately $329 million in 2004 and $56 million in 2003 and 2002 to the NDTF. These contributions are presented in Other within Cash Flows From Investing Activities on the Consolidated Statements of Cash Flows. Realized and unrealized gains and losses on sales of investments within the NDTF are recorded in Other within Regulatory Assets and Deferred Debits and Other within Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

## 10. Goodwill

Duke Energy evaluates the impairment of goodwill under the guidance of SFAS No. 142. As a result of the annual impairment tests required by SFAS No. 142, no charge for the impairment of goodwill was recorded in 2004.

In 2003, Duke Energy recorded a goodwill impairment charge of $254 million to write off all DENA goodwill, most of which related to DENA's trading and marketing business. This impairment charge reflected the reduction in scope and scale of DETM's business and the continued deterioration of market conditions affecting DENA during 2003. Duke Energy used a discounted cash flow analysis to determine fair value. Key assumptions in the analysis included the use of an appropriate discount rate, estimated future cash flows and an estimated run rate of general and administrative costs. In estimating cash flows, Duke Energy incorporated current market information, historical factors and fundamental analysis, and other factors into its forecasted commodity prices. This charge is recorded in the Consolidated Statements of Operations as Impairment of Goodwill.

In 2002, Duke Energy recorded a goodwill impairment charge of $194 million related to International Energy's European trading and gas marketing business (European Business), substantially all of which was sold in the fourth quarter of 2003. Significant changes in the European market and operating results adversely affected Duke Energy's outlook for this reporting unit. The exit of key market participants and a tightening of credit requirements were the primary drivers of this revised outlook. The fair value of the European reporting unit was estimated using a discounted cash flow analysis, which included key assumptions including the use of an appropriate discount rate, estimated future cash flows and an estimated run rate of general and administrative costs. In estimating cash flows, Duke Energy incorporated current market information, historical factors and fundamental analysis, and other factors in determining estimated future cash flows. This charge is recorded in the Consolidated Statements of Operations in Discontinued Operations—Net Operating Loss, net of tax. See Note 13 for further information regarding the European reporting unit and its treatment as discontinued operations in the Consolidated Statements of Operations.

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**Notes To Consolidated Financial Statements—(Continued)**

**Changes in the Carrying Amount of Goodwill**

| | Balance December 31, 2003 | Impairments | Dispositions | Other[a] | Balance December 31, 2004 |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| Natural Gas Transmission | $3,224 | $— | $— | $174 | $3,398 |
| Field Services | 493 | — | — | 5 | 498 |
| International Energy | 238 | — | — | 7 | 245 |
| Crescent | 7 | — | — | — | 7 |
| Total consolidated | $3,962 | $— | $— | $186 | $4,148 |

| | Balance December 31, 2002 | Impairments | Dispositions[c] | Other[a] | Balance December 31, 2003 |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| Natural Gas Transmission | $2,760 | $ — | $(27) | $491 | $3,224 |
| Field Services | 481 | — | — | 12 | 493 |
| DENA | 100 | (100) | — | — | — |
| International Energy | 246 | — | (5) | (3) | 238 |
| Crescent | 6 | — | — | 1 | 7 |
| Other[b] | 154 | (154) | — | — | — |
| Total consolidated | $3,747 | $(254) | $(32) | $501 | $3,962 |

(a) Amounts consist primarily of foreign currency translation and purchase price adjustments to prior year acquisitions.
(b) Amount represents corporate goodwill that is allocated to DENA for the purpose of impairment testing pursuant to SFAS No. 142. As a result, the impairment charge in 2003 was recorded in the DENA segment.
(c) Amounts were included in the disposal of a portion of a reporting unit within Natural Gas Transmission and International Energy.

## 11. Investments in Unconsolidated Affiliates and Related Party Transactions

Investments in domestic and international affiliates that are not controlled by Duke Energy, but over which it has significant influence, are accounted for using the equity method. Duke Energy received distributions of $139 million in 2004, $263 million in 2003, and $369 million in 2002 from those investments. These amounts are included in Other, assets within Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows. Duke Energy's share of net earnings from these unconsolidated affiliates is reflected in the Consolidated Statements of Operations as Equity in Earnings of Unconsolidated Affiliates. (See Note 2 for 2004 dispositions.)

As of December 31, 2004 and December 31, 2003, investments in affiliates were carried at approximately $91 million and $66 million, respectively, less than the amount of underlying equity in net assets (7% of total investment in affiliates as of December 31, 2004 and 5% as of December 31, 2003). This amount is related to the difference in the carrying amount and the underlying net assets of investments owned by Field Services. Such difference has been fully allocated to the respective investee's long-lived assets and the amounts are being amortized into income over the life of the underlying related long-lived assets.

**Natural Gas Transmission.** As of December 31, 2004 investments primarily included a 50% interest in Gulfstream Natural Gas System, LLC (Gulfstream). Gulfstream is an interstate natural gas pipeline that extends from Mississippi and Alabama across the Gulf of Mexico to Florida. Although Duke Energy owns a significant portion of Gulfstream, it is not consolidated as Duke Energy does not hold a majority of voting control or have the ability to exercise control over Gulfstream.

**Field Services.** As of December 31, 2004 investments primarily included a 33% interest in Discovery Producer, LLC, a natural gas gathering and processing system that includes a pipeline in the Gulf of Mexico and natural gas processing and fractionation facilities in Louisiana. As of December 31, 2004 Field Services also owned Texas Eastern Products Pipeline Company, LLC, the general partner of TEPPCO Partners, L.P. (TEPPCO), a publicly traded master limited partnership which owns and operates a network of pipelines, storage and terminal facilities for refined products, liquefied petroleum gases, petrochemicals, natural gas and crude oil. The general partner is responsible for the management and operations of TEPPCO. See Note 23 for subsequent events disclosure.

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**Notes To Consolidated Financial Statements—(Continued)**

**DENA.** As of December 31, 2004 investments primarily included a 50% interest in Southwest Power Partners, LLC. Southwest Power Partners, LLC is a gas-fired combined-cycle facility in Arizona that serves markets in Arizona, Nevada and California. Although Duke Energy owns a significant portion of this investment, it is not consolidated as it does not hold a majority of voting control or have the ability to exercise control over this investment.

**International Energy.** As of December 31, 2004 investments primarily included a 25% indirect interest in National Methanol Company, which owns and operates a methanol and MTBE (methyl tertiary butyl ether) business in Jubail, Saudi Arabia. International Energy also has a 50% ownership in Compañia de Servicios de Compresiön de Campeche, S.A. de C.V. (Campeche), a natural gas compression facility in the Cantarell oil field in the Gulf of Mexico, and a 38% ownership in Aguaytia, a natural gas facility in Peru.

Campeche project revenues are generated from the gas compression services agreement (GCSA) with the Mexican national oil company (PEMEX). The current five year GCSA expires on October 31, 2006 and PEMEX has the option to renew the GCSA for an additional four years. Campeche has made a renewal offer to PEMEX that has been initially rejected; however, discussions continue with PEMEX regarding renewal of the contract or other possible arrangements. If it is determined that the renewal will not take place or another economically viable arrangement is not found, the value of International Energy's equity investment in Campeche would decline and such investment would be written down to its resulting fair value. International Energy's estimated maximum exposure to this risk is potential impairment or other charges of $70 million.

**Crescent.** As of December 31, 2004 investments included various real estate development projects.

**Other.** As of December 31, 2004 investments primarily included participation in various construction and support activities for fossil-fueled generating plants through D/FD.

**Investments in Unconsolidated Affiliates**

| | As of: | | | | | |
|---|---|---|---|---|---|---|
| | December 31, 2004 | | | December 31, 2003 | | |
| | Domestic | International | Total | Domestic | International | Total |
| | | | (in millions) | | | |
| Natural Gas Transmission | $ 769 | $ 3 | $ 772 | $ 787 | $ 5 | $ 792 |
| Field Services | 157 | — | 157 | 194 | — | 194 |
| DENA | 134 | 18 | 152 | 139 | 39 | 178 |
| International Energy | — | 167 | 167 | — | 147 | 147 |
| Crescent | 20 | — | 20 | 15 | — | 15 |
| Other | 17 | 7 | 24 | 66 | 6 | 72 |
| Total | $1,097 | $195 | $1,292 | $1,201 | $197 | $1,398 |

**Equity in Earnings of Unconsolidated Affiliates**

| | For the Years Ended: | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | December 31, 2004 | | | December 31, 2003 | | | December 31, 2002 | | |
| | Domestic | International | Total | Domestic | International | Total | Domestic | International | Total |
| | | | | | (in millions) | | | | |
| Natural Gas Transmission | $ 26 | $ (1) | $ 25 | $19 | $ 8 | $ 27 | $ 87 | $19 | $106 |
| Field Services | 60 | — | 60 | 56 | — | 56 | 60 | — | 60 |
| DENA | — | 5 | 5 | 22 | (2) | 20 | 39 | 5 | 44 |
| International Energy | — | 51 | 51 | — | 27 | 27 | — | 63 | 63 |
| Crescent | 3 | — | 3 | — | — | — | — | — | — |
| Other[(a)] | 16 | 1 | 17 | (9) | 2 | (7) | (54) | (1) | (55) |
| Total | $105 | $56 | $161 | $88 | $35 | $123 | $132 | $86 | $218 |

(a) Includes equity investments at the corporate level and the elimination of 50% of the profit earned by D/FD on construction projects with DENA and Duke Power. D/FD is 50% owned by Duke Energy. See additional information in the Related Party Transactions section that follows.

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## Notes To Consolidated Financial Statements—(Continued)

**Summarized Combined Financial Information of Unconsolidated Affiliates**

| | As of December 31, 2004 | As of December 31, 2003 |
|---|---|---|
| | (in millions) | |
| **Balance Sheet** | | |
| Current assets | $ 1,413 | $ 1,552 |
| Noncurrent assets | 6,028 | 8,435 |
| Current liabilities | (1,118) | (979) |
| Noncurrent liabilities | (2,078) | (4,062) |
| Net assets | $ 4,245 | $ 4,946 |

| | For the Years Ended December 31, 2004 | 2003 | 2002 |
|---|---|---|---|
| | (in millions) | | |
| **Income Statement** | | | |
| Operating revenues | $7,326 | $6,253 | $6,072 |
| Operating expenses | 6,872 | 5,526 | 5,094 |
| Net income | 415 | 550 | 830 |

**Related Party Transactions.** Outstanding notes receivable from unconsolidated affiliates were $89 million as of December 31, 2004 and $146 million as of December 31, 2003. Amounts are included in Notes Receivable on the Consolidated Balance Sheets. Of the notes outstanding as of December 31, 2004, $50 million related to International Energy's note receivable from the Campeche project, a 50% owned joint venture, $25 million related to a note from a partnership in which Natural Gas Transmission has 50% ownership, and the remaining $14 million related to notes that Crescent had with partners in three of its joint ventures. These outstanding notes receivables had interest rates at or above current market rates.

International Energy loaned money to Campeche to assist in the costs to build. During 2004, International Energy received principal and interest payments of $7 million from Campeche, a 50% owned DEI affiliate. Payments from Campeche in 2003 and 2002 were $8 million and $1 million, respectively.

Natural Gas Transmission has a 50% ownership in two pipeline companies, Gulfstream, an operating pipeline, and Islander East, LLC, a development stage pipeline. In addition, DENA has a 50% ownership in a power plant, McMahon Cogeneration Plant, a cogeneration natural gas fired facility. Natural Gas Transmission provides certain administrative and other services to the pipeline companies and the power plant. Natural Gas Transmission recorded recoveries of costs from these affiliates of $8 million, $12 million, and $14 million during 2004, 2003, and 2002, respectively. The outstanding receivable from these affiliates was $1 million and $2 million for 2004 and 2003, respectively.

Firm capacity payments to Alliance Pipeline and Vector Pipeline were $33 million and $30 million for 2003 and 2002, respectively. Natural Gas Transmission sold its ownership in these pipelines in 2003.

During 2002, Natural Gas Transmission recognized $28 million in earnings for a construction fee received from an unconsolidated affiliate related to the successful completion of Gulfstream.

Advance SC LLC, which provides funding for economic development projects, educational initiatives, and other programs, was formed during 2004. Duke Power made a $6.5 million donation to the nonconsolidated subsidiary during the year.

Field Services sells a portion of its residue gas and NGLs to, purchases raw natural gas and other petroleum products from, and provides gathering and transportation services to unconsolidated affiliates (primarily TEPPCO). Total revenues from these affiliates were approximately $278 million, $166 million, and $138 million for 2004, 2003, and 2002, respectively. Total purchases from these affiliates were approximately $125 million, $98 million, and $82 million for 2004, 2003, and 2002, respectively. Total operating expenses were $4 million for 2004 and 2003 and $1 million for 2002.

D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation. During 2003, Duke Energy and Fluor Corporation announced that they would dissolve the D/FD partnership. The D/FD partners adopted a plan for an orderly wind-down of the

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**Notes To Consolidated Financial Statements—(Continued)**

business which is expected to be completed by December 2005. Previously, D/FD provided comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide. D/FD was the primary builder of DENA's merchant generation plants. D/FD has built some plants for Duke Power. Fifty percent of the profit earned by D/FD for the construction of affiliates' generation plants, which is associated with Duke Energy's ownership, is either deferred in consolidation until the plant is sold or, once the plant becomes operational, the deferred profit is amortized over the plant's useful life or on an accelerated basis if the plants are impaired. Fifty percent of the profit earned by D/FD for operating and maintenance services for Duke Energy owned plants is eliminated in consolidation. For the year ended December 31, 2004, Duke Energy deferred profit of $2 million for D/FD construction contracts and did not eliminate any profit for operating and maintenance services. For the year ended December 31, 2003, Duke Energy deferred profit of $59 million for construction contracts and eliminated profit of less than one million for operating and maintenance services. For the year ended December 31, 2002, Duke Energy deferred profit of $159 million for construction contracts and eliminated profit of $3 million for operating and maintenance services. In addition, as part of the D/FD partnership agreement, excess cash is loaned at current market rates to Duke Energy and Fluor Enterprises, Inc. (See Note 15.)

In the normal course of business, Duke Energy's consolidated subsidiaries enter into energy trading contracts or other derivatives with one another. On a separate company basis, each subsidiary accounts for such contracts as if they were transacted with a third party and records the contracts using the MTM Model or the Accrual Model of Accounting (Accrual Model), as applicable. For example, DETM may enter into a contract to purchase natural gas from DEFS. DEFS may record this contract using accrual accounting, while DETM may mark the contract to market through its current earnings. In the consolidation process, the effects of this intercompany contract are eliminated, and not reflected in Duke Energy's Consolidated Financial Statements.

Also see Note 15, Debt and Credit Facilities, Note 17, Commitments and Contingencies, and Note 18, Guarantees and Indemnifications, and Note 23, Subsequent Events, for additional related party information.

## 12. Impairment, Severance, and Other Related Charges

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (in millions) | | |
| Duke Energy North America | $ 1 | $2,903 | $207 |
| Field Services | 22 | — | 78 |
| International Energy | — | — | 75 |
| Crescent | 42 | — | — |
| Other | — | 53 | 4 |
| Total Impairment and other related charges | $65 | $2,956 | $364 |

**Field Services.** In the third quarter of 2004, Field Services recorded impairments of approximately $22 million related to some of Field Services' operating assets. The majority of this charge relates to the MBPP exchange transaction discussed in Note 2.

Additionally, in the third quarter of 2004, Field Services recorded an impairment of approximately $23 million related to equity method investments at Field Services. The impairment is included in (Losses) Gains on Sales and Impairments of Equity Investments on the Consolidated Statements of Operations. The impairment charge was related to management's assessment of the recoverability of some equity method investments. Field Services determined that these assets, which are located in the Gulf Coast, were impaired; therefore they were written down to fair value. Fair value was determined based on management's best estimates of sales value and/or discounted future cash flow models.

The 2002 charges were primarily to write-off inventory and other current assets to their net realizable value.

**Crescent.** In the fourth quarter of 2004, Crescent recorded impairment charges of approximately $42 million related to two residential developments in Payson, Arizona, the Rim and Chaparral Pines, and one residential development in Austin, Texas, Twin Creeks. The impairment charges were related to long lived assets at the three properties. The developments have suffered from slower than anticipated absorption of available inventory. Fair value of the assets was determined based on management's assessment of current operating results and discounted future cash flow models. Crescent also recorded bad debt charges of $8 million related to notes

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receivable due from Rim Golf Investor, LLC and Chaparral Pines Investor, LLC. This amount is recorded in Operation, Maintenance and Other on the Consolidated Statement of Operations.

**DENA.** In the fourth quarter of 2003, as a result of deteriorating market conditions in the merchant energy industry, Duke Energy decided to exit the merchant power generation business in the Southeastern U.S. The carrying value of the Southeast Plants exceeded the fair value, resulting in an impairment charge in 2003 of approximately $1.3 billion. The fair value of the Southeast Plants was estimated primarily based on third party comparable sales, analysis from outside advisors and information available from efforts to sell certain of these assets. These assets were subsequently sold in the second quarter of 2004. (See Note 2.)

Also in the fourth quarter of 2003, Duke Energy decided not to fund completion of construction of three DENA merchant power plants located in Washington, Nevada and New Mexico (the deferred plants). The carrying value of these assets exceeded the fair value, resulting in an impairment charge in 2003 of approximately $1.1 billion. The fair value of the deferred plants was estimated based primarily on analysis from outside advisors and information available from efforts to sell certain of these assets. The deferred plants located in Nevada and New Mexico were sold in the fourth quarter of 2004. During 2004, Duke Energy reached an agreement to sell the partially completed plant located in Washington. (See Note 2.)

During 2003, Duke Energy agreed to sell a power generation plant in Maine and classified the asset as held for sale. The carrying value exceeded the negotiated sales price for the plant so an impairment charge of $72 million was recorded in 2003. Subsequently, in 2003, the anticipated transaction did not occur, and management decided not to sell the plant, thus removing the asset from held for sale.

DENA recorded additional impairment charges of $125 million in 2003, primarily associated with a change in the expected dispatch of Morro Bay, a plant in California, and a plan to sell an investment in Bayside, an unconsolidated affiliate. Fair value of these assets was estimated based primarily on discounted cash flow analysis.

Certain forward power contracts related to the Southeast Plants and the deferred plants had been primarily designated as normal purchases and sales in accordance with SFAS No. 133. In addition, certain forward gas contracts related to the long-lived assets had been designated as cash flow hedges in accordance with SFAS No. 133. As a result of the change in management intent for the long-lived assets, the related forward power and gas contracts were de-designated as normal purchases and sales and hedges. As a result, a net charge of $262 million was recorded.

As a result of the decisions discussed above, DENA recorded impairment charges in 2003 of approximately $2.9 billion, primarily related to electric generation plants which are classified as Property, Plant and Equipment on the Consolidated Balance Sheets and to mark the derivative contracts to market value and reclassify the hedge amounts previously included in AOCI in accordance with SFAS No. 133.

The 2002 impairment and other related charges included a partial impairment of uninstalled turbines and the termination of other turbines on order. Additionally, charges were recorded in 2002 to impair one of DENA's merchant power facilities, and write-off site development costs in California and an abandoned information technology system. Fair value of these assets was estimated based on comparable sales or discounted cash flow analysis.

**International Energy.** The 2002 charges were to write-off site development costs in Brazil and Bolivia, and to partially impair uninstalled turbines.

**Other.** The 2003 charges were due primarily to the abandonment of a corporate risk management information system, primarily due to DENA exiting the proprietary trading business and the reduction of scope and scale of DETM's business.

During 2002, Duke Energy communicated a voluntary and involuntary severance program across all segments to align the business with market conditions during that period. Severance plans related to the program were amended effective August 1, 2004 and will apply to individuals notified of layoffs between that date and January 1, 2006. As of December 31, 2004, no additional substantial charges are expected to be incurred under the plan. Provision for severance is included in Operations, Maintenance and Other in the Consolidated Statements of Operations.

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## Notes To Consolidated Financial Statements—(Continued)

| Severance Reserve | Balance at January 1, 2004 | Provision/ Adjustments | Noncash Adjustments | Cash Reductions | Balance at December 31, 2004 |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| DEI | $ 6 | $— | $ (4) | $ (1) | $ 1 |
| DEFS[c] | 6 | 1 | — | (7) | — |
| Gas Transmission | 29 | 1 | (6) | (18) | 6 |
| Franchised Electric | 60 | — | (6) | (50) | 4 |
| DENA | 7 | 1 | (1) | (6) | 1 |
| Crescent | — | — | — | — | — |
| Other | 42 | 2 | (4) | (37) | 3 |
| Total[a] | $150 | $ 5 | $(21) | $(119) | $15 |

| | Balance at January 1, 2003 | Provision/ Adjustments | Noncash Adjustments | Cash Reductions | Balance at December 31, 2003 |
|---|---|---|---|---|---|
| DEI | $ 4 | $ 6 | $ (4) | $ — | $ 6 |
| DEFS[c] | — | 6 | — | — | 6 |
| Gas Transmission | 33 | 20 | 1 | (25) | 29 |
| Franchised Electric | 29 | 65 | — | (34) | 60 |
| DENA | 14 | 8 | (2) | (13) | 7 |
| Crescent | — | — | — | — | — |
| Other | 33 | 29 | — | (20) | 42 |
| Total[a][b] | $113 | $134 | $ (5) | $(92) | $150 |

| | Balance at January 1, 2002 | Provision/ Adjustments | Noncash Adjustments | Cash Reductions | Balance at December 31, 2002 |
|---|---|---|---|---|---|
| DEI | $ 5 | $ 2 | $ (2) | $ (1) | $ 4 |
| DEFS[c] | — | — | — | — | — |
| Gas Transmission | — | 54 | (1) | (20) | 33 |
| Franchised Electric | 7 | 28 | (1) | (5) | 29 |
| DENA | — | 26 | (12) | — | 14 |
| Crescent | — | — | — | — | — |
| Other | — | 34 | — | (1) | 33 |
| Total[a] | $ 12 | $144 | $(16) | $(27) | $113 |

(a) Substantially all expected severance costs will be applied to the reserves within one year.
(b) Provision in 2003 excludes $22 million of curtailment costs related to other post-retirement benefits.
(c) Includes minority interest.

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**Notes To Consolidated Financial Statements—(Continued)**

## 13. Discontinued Operations and Assets Held for Sale

**Discontinued Operations.** The following table summarizes, by segment, the amounts classified as Discontinued Operations, net of tax, in the Consolidated Statements of Operations.

**Discontinued Operations (in millions)**

| | | Operating Income (Loss) | | | Net Gain (Loss) on Dispositions | | |
|---|---|---|---|---|---|---|---|
| | Operating Revenues | Pre-tax Operating Income (Loss) | Income Tax Expense (Benefit) | Operating Income (Loss), Net of Tax | Pre-tax Gain (Loss) on Dispositions | Income Tax Expense (Benefit) | Gain (Loss) on Dispositions, Net of Tax |
| **Year Ended December 31, 2004** | | | | | | | |
| Field Services | $ 79 | $ 3 | $ 1 | $ 2 | $ (17) | $ (6) | $ (11) |
| DENA | 109 | (2) | (1) | (1) | — | — | — |
| International Energy | 85 | (13) | (1) | (12) | 295 | 22 | 273 |
| Crescent | 2 | — | — | — | 9 | 4 | 5 |
| Other | 1 | 2 | 1 | 1 | 1 | — | 1 |
| Total consolidated | $ 276 | $ (10) | $— | $ (10) | $ 288 | $ 20 | $ 268 |
| **Year Ended December 31, 2003** | | | | | | | |
| Field Services | $ 345 | $ 9 | $ 3 | $ 6 | $ 19 | $ 7 | $ 12 |
| International Energy | 759 | (34) | (4) | (30) | (242) | (119) | (123) |
| Crescent | 5 | — | — | — | 18 | 7 | 11 |
| Other | 30 | (4) | (1) | (3) | (49) | (18) | (31) |
| Total consolidated | $1,139 | $ (29) | $(2) | $ (27) | $(254) | $(123) | $(131) |
| **Year Ended December 31, 2002** | | | | | | | |
| Field Services | $ 299 | $ (23) | $(9) | $ (14) | $ — | $ — | $ — |
| International Energy | 133 | (256) | 7 | (263) | — | — | — |
| Other | 57 | 25 | 9 | 16 | — | — | — |
| Total consolidated | $ 489 | $(254) | $ 7 | $(261) | $ — | $ — | $ — |

***Field Services***

In December 2004, based upon management's assessment of the probable disposition of certain gathering, compression and transportation assets in Wyoming, Field Services classified these assets as "held for sale" in the Consolidated Balance Sheets as of December 31, 2004. The book value of these assets was written down by $4 million ($3 million net of minority interest) to $10 million, which represents the estimated fair value less cost to sell. The after tax loss and results of operations related to these assets were included in Discontinued Operations, net of tax, in the Consolidated Statements of Operations. In February 2005, these assets were exchanged for certain gathering assets in Oklahoma of equivalent fair value.

In December 2004, Field Services sold gas system and treating plant assets in Southeast New Mexico and South Texas, respectively. Field Services sold these assets for proceeds of approximately $6 million, with the carrying value being approximately equal to the sales price. The after tax loss and related results of operations were included in Discontinued Operations, net of tax, in the Consolidated Statements of Operations.

In September 2004, Field Services recorded an impairment charge of approximately $23 million ($16 million net of minority interest) related to management's current assessment of some additional gathering, processing, compression and transportation assets in Wyoming. The estimated fair value of these assets less cost to sell was $27 million and classified as "held for sale" in the Consolidated Balance Sheet as of December 31, 2004. The after tax loss and related results of operations were included in Discontinued Operations, net of tax, in the Consolidated Statements of Operations. In the first quarter of 2005, Field Services sold these assets for proceeds of $28 million, with the carrying value being approximately equal to the sales price.

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**Notes To Consolidated Financial Statements—(Continued)**

In February 2004, Field Services sold gas gathering and processing plant assets in West Texas to a third party purchaser for a sales price of approximately $62 million resulting in an immaterial gain. The after tax gain and results of operations related to these assets were included in Discontinued Operations, net of tax, in the Consolidated Statements of Operations.

In 2003, Field Services sold two packages of assets for a total sales price of $90 million. The after tax gain on these sales of $12 million and related operating results were included in Discontinued Operations, net of tax, in the Consolidated Statements of Operations. The assets sold consisted of various gas processing plants and gathering pipelines in Mississippi, Texas, Alabama, Louisiana and Oklahoma.

***DENA***

On September 21, 2004 DENA signed a purchase and sale agreement with affiliates of Irving Oil Limited (Irving), under which Irving will purchase DENA's 75% interest in Bayside Power L.P. (Bayside). Irving had the right to terminate the agreement at any time prior to February 21, 2005. Irving did not terminate this agreement within the deadline specified and the terms of the purchase and sale agreement are now binding. Closing will occur upon receipt of required third party consents and regulatory approvals which are expected sometime in the second quarter 2005. As a result of the above agreement, DENA presented the $40 million net assets of Bayside as "held for sale" in the Consolidated Balance Sheets as of December 31, 2004. After considering the minority ownership in Bayside, DENA's net investment in Bayside was $19 million at December 31, 2004. Bayside was consolidated with the adoption of FIN 46 on March 31, 2004. Therefore, Bayside's operating results for the period April 1 to December 31, 2004 are included in Discontinued Operations, net of tax, in the Consolidated Statements of Operations. Prior operating results, including the impairment of the investment in Bayside of $55 million recorded in 2003, are not included in Discontinued Operations, as Bayside was previously accounted for as an equity method investment.

***International Energy***

In 2003, International Energy restructured and began exiting its operations in Europe. International Energy sold its Dutch gas marketing business for $84 million and sold a power generation plant in France for $79 million. An after tax net gain of $11 million on these sales was included in Discontinued Operations—Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations. An income tax benefit of approximately $101 million was also recorded in 2003, primarily associated with the $194 million goodwill impairment recognized in 2002 for the gas marketing business in Europe, the 2003 sale of that business and certain other exit costs. This tax benefit was included in Discontinued Operations—Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations.

Associated with the sale of the European Business, International Energy holds a receivable from Norsk Hydro ASA with a fair value of $68 million as of December 31, 2004 and $63 million as of December 31, 2003. This receivable is included in Receivables in the Consolidated Balance Sheets as of December 31, 2003 and 2004. In 2004, International Energy recorded a $14 million ($9 million after tax) allowance for the note based on management's assessment of the probability of not collecting the entire note. The after tax loss was included in Discontinued Operations—Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations.

In order to eliminate exposure to international markets outside of Latin America and Canada, in 2003 International Energy decided to pursue a possible sale or initial public offering of International Energy's Asia-Pacific power generation and natural gas transmission business (the Asia-Pacific Business). As a result of this decision, International Energy recorded an after tax loss of $233 million during 2003, which represented the excess of the carrying value over the estimated fair value of the business, less estimated costs to sell. Fair value of the business was estimated based primarily on comparable third party sales and analysis from outside advisors. This after tax loss was included in Discontinued Operations—Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations.

In the first quarter of 2004, International Energy determined it was likely that a bid in excess of the originally determined fair value would be accepted and thus recorded a $238 million after-tax gain related to International Energy's Asia-Pacific Business. The after tax gain was included in Discontinued Operations-Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations and restored the loss recorded during the fourth quarter of 2003.

In April 2004, International Energy completed the sale of the Asia-Pacific Business to Alinta Ltd. for a gross sales price of approximately $1.2 billion (including $840 million debt retired by the buyer). This resulted in recording an additional $40 million after-tax gain in the second quarter of 2004. International Energy received approximately $390 million of cash proceeds, net of approximately $840 million of debt retired (as a non-cash financing activity) as part of the Asia-Pacific Business. In September 2004, International Energy repaid

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**Notes To Consolidated Financial Statements—(Continued)**

approximately $50 million of remaining Asia-Pacific debt from assets that were held in a fully-funded consolidated trust for the specific purpose of retiring the debt. The assets held in the consolidated trust were received from Alinta, Ltd. as part of the sale of the Asia-Pacific Business. The Asia-Pacific debt had been classified as Current and Non-Current Liabilities Associated with Assets Held for Sale in the Consolidated Balance Sheets as of December 31, 2003. All after tax gains related to this transaction and the results of operations for these assets are included in Discontinued Operations, net of tax, in the Consolidated Statements of Operations.

In 2003, International Energy completed the sale of its 85.7% majority interest in P.T. Puncakjaya Power (PJP) in Indonesia for $78 million. The sale resulted in a reduction to Duke Energy's consolidated indebtedness of $259 million. International Energy recorded an immaterial after tax loss on the sale, which was included in Discontinued Operations—Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations.

***Crescent***

Crescent routinely develops real estate projects and operates those facilities until they are substantially leased and a sales agreement is finalized. Crescent has several projects with distinguishable operations and cash flows which will be eliminated upon their sale. In the case Crescent does not retain any significant continuing involvement after the sale, Crescent classifies the project as "discontinued operations" as required by SFAS No. 144.

In 2004, Crescent sold one apartment complex, two residential and two commercial properties resulting in sales proceeds of approximately $52 million. The $5 million after tax gain on these sales was included in Discontinued Operations—Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations.

In 2003, Crescent sold three retail centers and one apartment complex, all located in Florida, for a total sales price of approximately $77 million. The $11 million after tax gain on these sales was included in Discontinued Operations—Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations.

***Other***

During 2003, Duke Energy decided to exit the merchant finance business conducted by DCP. As a result, Duke Energy recorded an approximately $17 million after tax loss, which represents the excess of the carrying value of the notes receivable over the fair value, less costs to sell. Fair value of the notes receivable was estimated based primarily on discounted cash flow analysis. The after tax loss was included in Discontinued Operations—Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations.

During 2004, Duke Energy received approximately $58 million from the sale or collection of all of DCP's notes receivable. An immaterial after tax gain related to these transactions was included in Discontinued Operations—Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations.

During 2003, Duke Energy sold Duke Energy Hydrocarbons LLC for approximately $83 million. Duke Energy recorded an approximate $14 million after tax loss on the sale, which was included in Discontinued Operations—Net Gain (Loss) on Dispositions, net of tax, in the Consolidated Statements of Operations.

**Assets Held for Sale.** The following are significant items classified as "held for sale" in the Consolidated Balance Sheet as of December 31, 2004:

- Some gathering, processing, compression and transportation assets owned by Field Services [a]
- DENA's Bayside facility[b]
- International Energy's European Business

The following are significant items classified as "held for sale" in the Consolidated Balance Sheet as of December 31, 2003:

- Some turbines and related equipment owned by DENA
- International Energy's European Business
- International Energy's Asia-Pacific Business[a]
- DCP's merchant finance business[a]

a Operating results for these businesses are classified as Discontinued Operations in the Consolidated Statements of Operations

b Bayside was consolidated as a result of the adoption of FIN 46 on March 31, 2004. As a result, Bayside's operating results for the period April 1 to December 31, 2004 are included in Discontinued Operations in the Consolidated Statements of Operations. Prior operating results are not included in Discontinued Operations.

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**Notes To Consolidated Financial Statements—(Continued)**

The following table presents the carrying values of the major classes of assets and associated liabilities held for sale in the Consolidated Balance Sheets as of December 31, 2004 and 2003.

***Summarized Balance Sheet Information for Assets and Associated Liabilities Held for Sale***

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| | (in millions) | |
| Current assets | $ 40 | $ 361 |
| Investments and other assets | 12 | 379 |
| Property, plant and equipment, net | 72 | 1,065 |
| Total assets held for sale | $124 | $1,805 |
| Current liabilities | $ 30 | $ 651 |
| Long-term debt | 14 | 514 |
| Deferred credits and other liabilities | — | 223 |
| Total liabilities associated with assets held for sale | $ 44 | $1,388 |

## 14. Property, Plant and Equipment

| | December 31, | |
|---|---|---|
| | 2004 | 2003 |
| | (in millions) | |
| Land[(a)] | $ 489 | $ 503 |
| Plant | | |
| Electric generation, distribution and transmission[(a)] | 23,937 | 23,577 |
| *Natural gas transmission and distribution* | 11,402 | 10,848 |
| Gathering and processing facilities[(a)] | 6,343 | 6,127 |
| Other buildings and improvements[(a)] | 440 | 448 |
| Nuclear fuel | 821 | 863 |
| Equipment | 1,150 | 1,162 |
| Vehicles | 136 | 135 |
| Construction in process | 715 | 1,007 |
| Other[(a)] | 1,373 | 1,317 |
| Total property, plant and equipment | 46,806 | 45,987 |
| Total accumulated depreciation[(b), (c)] | (13,300) | (12,139) |
| Total net property, plant and equipment | $ 33,506 | $ 33,848 |

(a) Includes capitalized leases: $87 million for 2004 and $136 million for 2003.
(b) Includes accumulated amortization of nuclear fuel: $550 million for 2004 and $604 million for 2003.
(c) Includes accumulated amortization of capitalized leases: $33 million for 2004 and $42 million for 2003.

Capitalized interest of $43 million for 2004, $132 million for 2003 and $250 million for 2002 is included in the Consolidated Statements of Operations.

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**Notes To Consolidated Financial Statements—(Continued)**

## 15. Debt and Credit Facilities

### Summary of Debt and Related Terms

| | Weighted-Average Rate | Year Due | December 31, 2004 | December 31, 2003 |
|---|---|---|---|---|
| | | (in millions) | | |
| Unsecured debt | 6.5% | 2005 – 2032 | $15,516 | $16,562 |
| Secured debt | 4.5% | 2005 – 2019 | 1,246 | 2,344 |
| First and refunding mortgage bonds | 4.6% | 2008 – 2027 | 1,215 | 1,215 |
| Trust preferred securities[(a)] | 7.5% | 2029 – 2039 | — | 876 |
| Capital leases | 11.6% | 2005 – 2032 | 195 | 210 |
| Other debt[(b)] | 4.2% | 2005 – 2017 | 381 | 466 |
| Commercial paper[(c)] | 2.5% | | 218 | 240 |
| *Preferred stock with sinking fund requirements*[(d)] | 6.8% | 2004 – 2015 | — | 25 |
| Fair value hedge carrying value adjustment | | 2005 – 2032 | 80 | 95 |
| Unamortized debt discount and premium, net | | | (19) | (81) |
| Total debt[(e), (f)] | | | 18,832 | 21,952 |
| Current maturities of long-term debt | | | (1,832) | (1,200) |
| Short-term notes payable and commercial paper[(g)] | | | (68) | (130) |
| Total long-term debt | | | $16,932 | $20,622 |

(a) Upon the implementation of SFAS No. 150, effective July 1, 2003, the trust preferred securities were reclassified to Long-term Debt from Guaranteed Preferred Beneficial Interests in Subordinated Notes of Duke Energy Corporation or Subsidiaries. Additionally, upon the adoption of the provisions of FIN 46R as of December 31, 2003, Duke Energy's remaining trust subsidiaries that had issued the trust preferred securities were deconsolidated since Duke Energy was not the primary beneficiary of the trust subsidiaries. This resulted in Duke Energy reflecting debt to affiliates in the December 31, 2003 Long-term Debt balance. During 2004, these trust preferred securities were redeemed for approximately $850 million.

(b) Includes $172 million of Duke Energy pollution control bonds as of December 31, 2004 and 2003. As of December 31, 2004 and 2003, $40 million was secured by first and refunding mortgage bonds and $77 million was secured by a letter of credit which in turn is secured by first and refunding mortgage bond.

(c) Includes $150 million as of December 31, 2004 and 2003 that was classified as Long-term Debt on the Consolidated Balance Sheets. The weighted-average days to maturity were 8 days as of December 31, 2004 and 18 days as of December 31, 2003.

(d) Upon the implementation of SFAS No. 150, effective July 1, 2003, the preferred stock with sinking fund requirements was reclassified to Long-term Debt from Preferred and Preference Stock with Sinking Fund Requirements. As of December 31, 2003, there were 250,000 issued and outstanding shares of 6.75% Preferred Stock, Series X issued in 1993.

(e) As of December 31, 2004, $485 million of debt was denominated in Brazilian Reals with the principal indexed annually to Brazilian inflation and $3,720 million of debt was denominated in Canadian dollars. As of December 31, 2003, $437 million of debt was denominated in Brazilian Reals with the principal indexed annually to Brazilian inflation and $3,673 million of debt was denominated in Canadian dollars.

(f) Balance at December 31, 2003 excludes approximately $890 million of long-term debt, notes payable and commercial paper denominated in Australian Dollars related to International Energy's Asia-Pacific Business. As of December 31, 2003, International Energy's Asia-Pacific Business was classified as discontinued operations, and the debt associated with the Asia-Pacific Business was reclassified to Current and Non-Current Liabilities Associated with Assets Held for Sale. During 2004, the debt was retired as part of the sale of the Asia-Pacific Business.

(g) Weighted-average rates on outstanding short-term notes payable and commercial paper was 2.5% as of December 31, 2004 and 1.7% as of December 31, 2003.

**Unsecured Debt.** In February 2004, Duke Capital remarketed $875 million of senior notes due in 2006, underlying its 8.25% Equity Units and reset the interest rate from 5.87% to 4.302%. As this action was contemplated in the original Equity Units issuance, the transaction had no immediate accounting implications. Subsequently, Duke Capital exchanged $475 million of the remarketed senior notes for $200 million of 4.37% senior unsecured notes due in 2009, and $288 million of 5.5% senior unsecured notes due in 2014. In accordance with EITF Issue No. 96-19, "Debtors Accounting for a Modification or Exchange of Debt Instruments," the $475 million of remarketed senior notes issued earlier at 4.302% was extinguished. This exchange transaction resulted in an approximate $11 million loss, which was included in Interest Expense in the Consolidated Statements of Operations for the year ended December 31, 2004. Proceeds from the remarketed notes were used to purchase U.S. Treasury securities that were held by the collateral agent and, upon maturity, were used to satisfy the forward stock purchase contract component of the 8.25% Equity Units in May of 2004.

Additionally, Duke Capital remarketed $750 million of its 4.32% senior notes due in 2006, underlying Duke Energy's 8.00% Equity Units on August 11, 2004. As a result of the remarketing, the interest rate on the notes was reset to 4.331%, effective August 16, 2004. Duke Capital subsequently exchanged $400 million of the 4.331% notes for $408 million of 5.668% notes due in 2014. This transaction resulted in an approximate $6 million loss, which was included in Interest Expense in the Consolidated Statements of Operations for the year end December 31, 2004. Proceeds from the remarketed notes were used to purchase U.S. Treasury securities held by the

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**Notes To Consolidated Financial Statements—(Continued)**

collateral agent and, upon maturity, were used to satisfy the forward stock purchase contract component of the 8% Equity Units in November 2004.

During 2004, Duke Capital purchased $202 million of its outstanding notes in the open market. These purchases included $140 million of Duke Capital 5.50% senior notes due March 1, 2014, $52 million of Duke Capital 4.37% senior notes due March 1, 2009 and $10 million of Duke Capital 6.75% senior noted due February 15, 2032. These securities were purchased at the then-current market price plus accrued interest.

In May 2004, Duke Energy redeemed its Series C 6.60% senior notes due in 2038, at a $200 million face value. As the securities were redeemed at par, security holders received $25 per each note held, plus accrued interest to the redemption date.

*Convertible Debt.* As of December 31, 2004, unsecured debt included $770 million of 1.75% convertible senior notes due in 2023. These senior notes, which were issued in May 2003, are convertible to Duke Energy common stock at a premium of 40% above the May 1, 2003 closing common stock market price of $16.85 per share. Upon conversion, the senior notes are potentially convertible into approximately 32.6 million shares of common stock. The conversion of these senior notes into shares of Duke Energy common stock is contingent on the occurrence of certain events during specified periods. These events include whether the price of Duke Energy common stock reaches specified thresholds, the credit rating of Duke Energy falls below certain thresholds, the convertible notes are called for redemption by Duke Energy, or specified transactions have occurred. The conditions that permit such conversion were not satisfied as of December 31, 2004. However, as a result of adopting the final consensus on EITF Issue No. 04-8, Duke Energy was required to include 32.6 million potential common shares related to Duke Energy's $770 million contingently convertible debt issuance as outstanding in the diluted EPS calculation at December 31, 2004. (See Note 19). Holders of the senior notes may require Duke Energy to purchase all or a portion of their senior notes for cash on May 15, 2007, May 15, 2012, and May 15, 2017, at a price equal to the principal amount of the senior notes plus accrued interest, if any. Duke Energy may redeem for cash all or a portion of the senior notes at any time on or after May 20, 2007, at a price equal to the sum of the issue price plus accrued interest, if any, on the redemption date.

In May 2004, Duke Energy issued 22,449,000 shares of its common stock in the settlement of the forward-purchase contract component of its Equity Units issued in March 2001. Under the terms of the contract, the Equity Unit holders were required to purchase common stock at a settlement rate based on the current market price of Duke Energy's common stock at the time of settlement with a floor and a ceiling. The rate was 0.6414 shares of stock per Equity Unit. Duke Energy received $875 million in proceeds as a result of the settlement, which was included in Proceeds from the Issuances of Common Stock and Common Stock Related to Employee Benefit Plans on the Consolidated Statement of Cash Flows.

In November 2004, Duke Energy issued 18,693,000 shares of its common stock in the settlement of the forward-purchase contract component of its Equity Units issued in November 2001. Under the terms of the contract, the Equity Unit holders were required to purchase stock at the time of settlement rate based on the current market price of Duke Energy's common stock at the time of the settlement with a floor and a ceiling. The rate was .6231 shares of stock per Equity Unit. Duke Energy received $750 million in proceeds as a result of the settlement, which was included in Proceeds from the Issuances of Common Stock and Common Stock Related to Employee Benefit Plans on the Consolidated Statement of Cash Flows.

**Secured Debt.** *Accounts Receivable Securitization.* During 2003, Duke Energy completed a securitization of certain accounts receivable through Duke Energy Receivables Finance Company, LLC (DERF), a newly formed, bankruptcy remote, special purpose subsidiary. DERF is a wholly owned limited liability company with a separate legal existence from its parent, and its assets are not intended to be generally available to creditors of Duke Energy. As a result of the securitization, Duke Energy sold, and will continue to sell on a daily basis to DERF, certain accounts receivable arising from the sale of electricity and/or related services as part of Duke Energy's franchised electric business. The proceeds from the initial sale of the accounts receivable to DERF were used for general corporate purposes in its franchised electric business, which included the repayment of outstanding commercial paper. In order to fund its purchases of accounts receivable, DERF entered into a two-year $300 million secured credit facility, with a commercial paper conduit administered by Citicorp North America, Inc. The credit facility has been subsequently amended to terminate in September 2006. The credit facility and related securitization documentation contain several covenants, including covenants with respect to the accounts receivable held by DERF as well as a covenant requiring that the ratio of Duke Energy consolidated indebtedness to Duke Energy consolidated capitalization not exceed 65%. As of December 31, 2004, the interest rate associated with the credit facility, which is based on commercial paper rates, was 2.7% and $300 million was outstanding under the credit facility. The securitization transaction was not structured to meet the criteria for sale treatment under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and accordingly is reflected as a secured borrowing in the Consolidated Financial Statements. As of December 31, 2004, the $300 million

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**Notes To Consolidated Financial Statements—(Continued)**

outstanding balance of the credit facility was secured by approximately $447 million of accounts receivable held by DERF. The obligations of DERF under the credit facility are non-recourse to Duke Energy.

*Other Assets Pledged as Collateral.* As of December 31, 2004, secured debt also consisted of various project financings, including Maritimes & Northeast Pipeline, LLC, Maritimes & Northeast Pipeline, LP (collectively, M&N Pipeline) and certain projects at Crescent. A portion of the assets, ownership interest and business contracts in these various projects are pledged as collateral. Additionally, as of December 31, 2004, substantially all of Franchised Electric's electric plant in service was subject to a mortgage lien securing the first and refunding mortgage bonds.

**Floating Rate Debt.** Unsecured debt, secured debt and other debt included approximately $1.5 billion of floating-rate debt as of December 31, 2004, and $2.7 billion as of December 31, 2003. Floating-rate debt is primarily based on commercial paper rates or a spread relative to an index such as a London Interbank Offered Rate for debt denominated in U.S. dollars, and Banker's Acceptances for debt denominated in Canadian dollars. As of December 31, 2004, the average interest rate associated with floating-rate debt was 2.6%.

In October 2004, Duke Energy prepaid a portion of a $994 million floating rate facility at DENA. The payment consisted of $565 million of principal, an associated $35 million working capital facility and accrued interest on the facilities. Additionally, in December 2004, Duke Energy repaid the remaining outstanding balance of $429 million.

**Related Party Debt.** Other debt included $17 million related to a loan with D/FD as of December 31, 2004, and $78 million as of December 31, 2003. As part of the D/FD partnership agreement, excess cash has been loaned, without stated repayment terms, at current market rates to Duke Energy and Fluor Enterprises, Inc. The weighted-average rate of this loan was 1.98% as of December 31, 2004 and 1.52% as of December 31, 2003. During 2003, Duke Energy and Fluor Corporation announced that they would dissolve the D/FD partnership. The D/FD partners have adopted a plan for an orderly wind-down of the business by December 2005. The entire outstanding balance of the loan with D/FD has been classified as Current Maturities of Long-term Debt on the December 31, 2004 and 2003 Consolidated Balance Sheets.

Upon the adoption of the provisions of FIN 46R as of December 31, 2003, as discussed in Note 1, Duke Energy's remaining trust subsidiaries that had issued the trust preferred securities were deconsolidated since Duke Energy was not the primary beneficiary of the trust subsidiaries. The deconsolidation of the remaining trust subsidiaries resulted in Duke Energy reflecting debt to affiliates of $876 million to the trust subsidiaries in Long-term Debt on the December 31, 2003 Consolidated Balance Sheet. As of December 31, 2003, the debt to affiliates consisted of the following issuances: $360 million of 7.20% notes due in 2037, $258 million of 7.20% notes due in 2039 and $258 million of 8.375% notes due in 2029. During 2004, all of the issuances were redeemed for approximately $850 million. As the securities were redeemed at par, security holders received $25 per each note held, plus accrued and unpaid distributions to the redemption date.

**Maturities, Call Options and Acceleration Clauses.**

**Annual Maturities as of December 31, 2004**

| | (in millions) |
|---|---|
| 2005 | $ 1,832 |
| 2006 | 1,991 |
| 2007 | 740 |
| 2008 | 1,202 |
| 2009 | 1,197 |
| Thereafter | 11,802 |
| Total long-term debt[a] | $18,764 |

(a) Excludes short-term notes payable and commercial paper of $68 million.

Annual maturities after 2009 include $450 million of long-term debt with call options, which provide Duke Energy with the option to potentially repay the debt early. Based on the years in which Duke Energy may first exercise its redemption options, it could potentially repay $100 million in 2005, $250 million in 2006, and $100 million in 2007.

Duke Energy may be required to repay certain debt should its credit ratings fall to a certain level at Standard & Poor's (S&P) or Moody's Investor Service (Moody's). As of December 31, 2004, Duke Energy had $17 million of senior unsecured notes which mature

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## Notes To Consolidated Financial Statements—(Continued)

serially through 2012 that may be required to be repaid if Duke Energy's senior unsecured debt ratings fall below BBB- at S&P or Baa3 at Moody's, and $28 million of senior unsecured notes which mature serially through 2016 that may be required to be repaid if Duke Energy's senior unsecured debt ratings fall below BBB at S&P or Baa2 at Moody's. As of March 1, 2004, Duke Energy's senior unsecured credit rating was BBB at S&P and Baa1 at Moody's.

**Available Credit Facilities and Restrictive Debt Covenants.** As of December 31, 2004, credit facilities capacity was reduced by approximately $560 million compared to December 31, 2003, primarily related to the divested Asia-Pacific Business as discussed in Note 13. In addition, Duke Energy and DEFS renewed and replaced their credit facilities at lower amounts due to the reduced need for credit capacity. In October 2004, Duke Capital added two new credit facilities, including a $120 million bilateral credit facility with an expiration date of July 15, 2009 and a $130 million bilateral credit facility with an expiration date of October 18, 2007. Duke Capital intends to use both of these facilities for issuing letters of credit to support the business activities of its subsidiaries. The issuance of commercial paper, letters of credit and other borrowings reduces the amount available under the credit facilities.

Duke Energy's credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2004, Duke Energy was in compliance with those covenants. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the credit agreements contain material adverse change clauses or any covenants based on credit ratings.

**Credit Facilities Summary as of December 31, 2004**

| | | | Amounts Outstanding | | |
|---|---|---|---|---|---|
| | Expiration Date | Credit Facilities Capacity | Commercial Paper | Letters of Credit | Total |
| **Duke Energy** | | | | | |
| $500 three-year syndicated[(a), (b)] | June 2007 | | | | |
| $150 two-year bilateral[(a), (b)] | September 2005 | | | | |
| Total Duke Energy | | $ 650 | $150 | $ — | $150 |
| **Duke Capital LLC** | | | | | |
| $600 364-day syndicated[(a), (b), (c)] | June 2005 | | | | |
| $600 three-year syndicated[(a), (b), (c)] | June 2007 | | | | |
| $130 three-year bi-lateral[(b), (c)] | October 2007 | | | | |
| $120 multi-year bi-lateral[(b), (c)] | July 2009 | | | | |
| Total Duke Capital LLC | | 1,450 | — | 732 | 732 |
| **Westcoast Energy Inc.** | | | | | |
| $166 three-year syndicated[(b), (e)] | June 2007 | | | | |
| $83 two-year syndicated[(b), (d)] | July 2005 | | | | |
| Total Westcoast Energy Inc. | | 249 | — | — | — |
| **Union Gas Limited** | | | | | |
| $249 364-day syndicated[(f), (g)] | June 2005 | 249 | 68 | — | 68 |
| **Duke Energy Field Services, LLC** | | | | | |
| $250 364-day syndicated[(c), (h), (i), (j)] | May 2005 | 250 | — | — | — |
| Total[(k)] | | $2,848 | $218 | $732 | $950 |

(a) Credit facility contains an option allowing borrowing up to the full amount of the facility on the day of initial expiration for up to one year.
(b) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%.
(c) Credit facility contains an interest coverage covenant.
(d) Credit facility is denominated in Canadian dollars, and was 100 million Canadian dollars as of December 31, 2004.
(e) Credit facility is denominated in Canadian dollars, and was 200 million Canadian dollars as of December 31, 2004.
(f) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 75%. Credit facility is denominated in Canadian dollars, and was 300 million Canadian dollars as of December 31, 2004.
(g) Credit facility contains an option at maturity allowing for the conversion of all outstanding loans to a term loan repayable up to one year after maturity date but not exceeding 18 months from the date of draw.
(h) Credit facility contains an option at maturity allowing for the conversion of all outstanding loans to a term loan repayable up to one year after maturity date.
(i) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 53%.
(j) In December 2004, the credit facility expiration date was extended from March 2005 to May 2005.
(k) Various credit facilities that support ongoing operations and miscellaneous transactions are not included in this credit facilities summary.

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*Preferred and Preference Stock of Duke Energy's Subsidiaries.* In June 2004, Westcoast redeemed all remaining outstanding Cumulative Redeemable First Preferred Shares, Series 6. The Series 6 Shares were redeemed for 25.00 per share in Canadian dollars plus all accrued and unpaid dividends to the date of redemption for a total redemption amount of approximately 104 million Canadian dollars.

In October 2004, Westcoast redeemed all remaining outstanding Cumulative Redeemable First Preferred Shares, Series 9. The Series 9 Shares were redeemed for 25.00 per share in Canadian dollars plus all accrued and unpaid dividends to the date of redemption for a total redemption amount of 125 million Canadian dollars.

Duke Energy has approximately $1,300 million of credit facilities which expire in 2005. It is Duke Energy's intent to resyndicate the $1,300 million of expiring credit facilities.

**Other Loans.** During 2004 and 2003, Duke Energy had loans outstanding against the cash surrender value of the life insurance policies that it owns on the lives of its executives. The amounts outstanding were $508 million as of December 31, 2004 and $467 million as of December 31, 2003. The amounts outstanding were carried as a reduction of the related cash surrender value that is included in Other Assets on the Consolidated Balance Sheets.

## 16. Preferred and Preference Stock at Duke Energy

**Authorized Shares of Duke Energy Preferred and Preference Stock as of December 31, 2004 and 2003**

| | Par Value | Shares |
|---|---|---|
| | | (in millions) |
| Preferred Stock | $100 | 12.5 |
| Preferred Stock A | $ 25 | 10.0 |
| Preference Stock | $100 | 1.5 |

As of December 31, 2004 and 2003, there were no shares of preference stock outstanding at Duke Energy.

**Preferred Stock without Sinking Fund Requirements.** The following table details Preferred Stock without Sinking Fund Requirements, which are not mandatorily redeemable financial instruments under the provisions of SFAS No. 150, as of the December 31, 2004 and 2003 Consolidated Balance Sheets.

**Preferred Stock without Sinking Fund Requirements**

| Rate/Series | Year Issued | Shares Issued and Outstanding at December 31, 2004 | December 31, 2004 | December 31, 2003 |
|---|---|---|---|---|
| | | | (dollars in millions) | |
| 4.50% C | 1964 | 175,000 | $ 18 | $ 18 |
| 7.85% S | 1992 | 300,000 | 30 | 30 |
| 7.00% W | 1993 | 249,989 | 25 | 25 |
| 7.04% Y | 1993 | 299,995 | 30 | 30 |
| 6.375% (Preferred Stock A) | 1993 | 1,257,185 | 31 | 31 |
| Total | | | $134 | $134 |

Duke Energy has the option, but not the obligation to redeem the Preferred Stock without Sinking Fund Requirements at prices above par, but not to exceed 104% of par value, plus accumulated dividends to the redemption date. Additionally, the holders of the Preferred Stock without Sinking Fund Requirements are entitled to redeem their preferred shares at par value in the event of an involuntary liquidation or dissolution of Duke Energy, or at 105% of par value in the event of a voluntary liquidation or dissolution of Duke Energy. Therefore, in accordance with SEC rules, the Preferred Stock without Sinking Fund Requirements is classified in mezzanine equity as Preferred and Preference Stock without Sinking Fund Requirements.

**Preferred and Preference Stock of Duke Energy's Subsidiaries.** In connection with the Westcoast acquisition in 2002, Duke Energy assumed approximately $411 million of authorized and issued redeemable preferred and preference shares at Westcoast and Union Gas. As of December 31, 2004 and 2003, these preferred and preference shares at Westcoast and Union Gas totaled $225 and $401 million, respectively. Since these preferred and preference shares are redeemable at the option of holder, as well as Westcoast and

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Union Gas, these preferred and preference shares do not meet the definition of a mandatorily redeemable instrument under SFAS No. 150. As such, these preferred and preference shares are considered contingently redeemable shares and are included in Minority Interests on the Consolidated Balance Sheets.

## 17. Commitments and Contingencies

### General Insurance

Duke Energy carries, through its captive insurance company, Bison, and its affiliates, insurance and reinsurance coverages consistent with companies engaged in similar commercial operations with similar type properties. Duke Energy's insurance coverage includes (1) commercial general public liability insurance for liabilities arising to third parties for bodily injury and property damage resulting from Duke Energy's operations; (2) workers' compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage, (4) financial services insurance policies in support of the indemnification provisions of the company's by-laws and (5) property insurance covering the replacement value of all real and personal property damage, excluding electric transmission and distribution lines, including damages arising from boiler and machinery breakdowns, earthquake, flood damage and business interruption/extra expense. All coverages are subject to certain deductibles, terms and conditions common for companies with similar types of operations.

Bison is a member of Oil Insurance Limited (OIL) and sEnergy Insurance Limited (sEnergy), which provides property and business interruption reinsurance coverage respectively for Duke Energy's non-nuclear facilities, and accounts for its membership under the cost method, as Duke Energy does not have the ability to exert significant influence. Should Bison terminate its membership in either OIL, sEnergy or both, it could be liable for additional premium assessments. Bison continues to be a member of OIL and sEnergy in 2005 and purchases coverages provided by both companies.

Duke Energy also maintains excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. Limits, terms, conditions and deductibles are comparable to those carried by other energy companies of similar size. The cost of Duke Energy's general insurance coverages continued to fluctuate over the past year reflecting the changing conditions of the insurance markets.

### Nuclear Insurance

Duke Energy owns and operates the McGuire and Oconee Nuclear Stations and operates and has a partial ownership interest in the Catawba Nuclear Station. The McGuire and Catawba Nuclear Stations have two nuclear reactors each and Oconee has three. Nuclear insurance includes: liability coverage; property, decontamination and premature decommissioning coverage; and business interruption and/or extra expense coverage. The other joint owners of the Catawba Nuclear Station reimburse Duke Energy for certain expenses associated with nuclear insurance premiums. The Price-Anderson Act requires Duke Energy to insure against public liability claims resulting from nuclear incidents to the full limit of liability, 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, the maximum amount of available private primary insurance increased from $200 million to $300 million and Duke Energy increased coverages on both nuclear liability and certain worker tort claim insurance to $300 million.

*Excess Liability Insurance.* This policy currently provides approximately $10.5 billion of coverage through the Price-Anderson Act's mandatory industry-wide excess secondary insurance program of risk pooling. The $10.5 billion is the sum of the current potential cumulative retrospective premium assessments of $101 million per licensed commercial nuclear reactor. This would be increased by $101 million for each additional commercial nuclear reactor licensed, or reduced by $101 million for nuclear reactors 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 U.S. If such an incident should occur and public liability damages exceed primary insurances, 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 is subject to indexing for inflation and may be subject to state premium taxes.

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**Notes To Consolidated Financial Statements—(Continued)**

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 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: $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 McGuire and Catawba unit is insured for up to $3.5 million per week, and the Oconee units are insured for up to $2.8 million per week. Coverage amounts 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 exceed its reserves for any of the above three programs, Duke Energy is liable for assessments of up to 10 times its annual premiums. The current potential maximum assessments are: Primary Property Insurance—$35 million, Excess Property Insurance—$44 million and Business Interruption Insurance—$29 million.

The other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of 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.

**Environmental**

Duke Energy is subject to international, federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters.

*Remediation activities.* Like others in the energy industry, Duke Energy and its affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of ongoing Duke Energy operations, sites formerly owned or used by Duke Energy entities, and sites owned by third parties. Remediation typically involves management of contaminated soils and may involve ground water remediation. Managed in conjunction with relevant federal, state and local agencies, activities vary, as a function of site conditions and locations, remedial requirements, complexity and sharing of responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, Duke Energy or its affiliates could potentially be held responsible for contamination caused by other parties. In some instances, Duke Energy may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. All of these sites generally are managed in the normal course of business or affiliate operations. Management believes that completion or resolution of these matters will have no material adverse effect on consolidated results of operations, cash flows or financial position.

*Clean Water Act.* The Environmental Protection Agency's (EPA's) final Clean Water Act Section 316(b) rule became effective July 9, 2004. The rule establishes best technology available (BTA) requirements for existing steam electric generating facilities' cooling water intake structures to protect fish and other aquatic organisms. Eight of Duke Energy's eleven coal and nuclear-fueled generating facilities in North Carolina and South Carolina and its three natural gas-fired generating facilities in California are affected sources under the rule. The rule requires a Comprehensive Demonstration Study (CDS) for each affected facility to generate information for use in determining necessary facility-specific BTA requirements and cost estimates for implementation. These studies will be completed over the next three to five years. Once compliance measures for a facility are determined and approved by regulators, each facility will typically have five or more years to implement the measures. Due to the wide range of BTA measures potentially applicable to a given facility, and since the final selection of compliance measures will be at least partially dependent upon the CDS information, Duke Energy is not able to estimate its cost for complying with the rule at this time.

*Air Quality Control.* In 1998, the EPA issued a final rule on regional ozone control that required 22 eastern states and the District of Columbia to revise their State Implementation Plans (SIPs) to significantly reduce emissions of nitrogen oxide by May 1, 2003. The EPA rule was challenged in court by various states, industry and other interests, including Duke Energy and the states of North Carolina and South Carolina. In 2000, the court upheld most aspects of the EPA rule. The same court subsequently extended the compliance deadline for emission reductions to May 31, 2004. Both North Carolina and South Carolina have revised their SIPs in response to the

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EPA's 1998 rule, and the EPA has approved those revisions. Duke Energy has completed all necessary actions to meet the EPA rule and requirements, incurring approximately $653 million in capital costs for emission controls.

*North Carolina Clean Air Legislation.* As discussed in Note 4, in 2002, the state of North Carolina passed clean air legislation in order for North Carolina electric utilities, including Duke Energy, to significantly reduce emissions of sulfur dioxide and nitrogen oxides from coal-fired power plants in the state over the next ten years.

*Extended Environmental Activities, Accruals.* Included in Other Current Liabilities and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets were accruals related to extended environmental-related activities of $83 million as of December 31, 2004 and $94 million as of December 31, 2003. The accrual for extended environmental-related activities represents Duke Energy's provisions for costs associated with remediation activities at some of its current and former sites and other relevant environmental contingent liabilities. Management believes that completion or resolution of these matters will have no material adverse effect on consolidated results of operations, cash flows, or financial position.

**Litigation**

*New Source Review (NSR)/EPA Litigation.* In 2000, the U.S. Justice Department, acting on behalf of the EPA, filed a complaint against Duke Energy in the U.S. District Court in Greensboro, North Carolina, for alleged violations of the NSR provisions of the Clean Air Act (CAA). The EPA claims that 29 projects performed at 25 of Duke Energy's coal-fired units were major modifications, as defined in the CAA, and that Duke Energy violated the CAA's NSR requirements when it undertook those projects without obtaining permits and installing emission controls for sulfur dioxide, nitrogen oxide and particulate matter. The complaint asks the court to order Duke Energy to stop operating the coal-fired units identified in the complaint, install additional emission controls and pay unspecified civil penalties.

Duke Energy asserts that there were no CAA violations because the applicable regulations do not require permitting in cases where the projects undertaken are "routine" or otherwise do not result in a net increase in emissions. Moreover, the EPA's allegations run counter to previous EPA guidance regarding the applicability of the NSR permitting requirements. In 2003, the trial court issued an opinion in response to the parties' motions for summary judgment which effectively adopted Duke Energy's position regarding the legal tests for determining what is "routine" and for calculation of emissions. Based upon a joint motion of the parties in the case, the court in April 2004 entered an Order and Final Judgment finding in favor of Duke Energy. The joint motion notified the court that the government could not prove its allegations at trial against Duke Energy in light of the legal standards established by the court in its 2003 order. The judgment reflects that Duke Energy did not violate the NSR program under the CAA. The government appealed the judgment to the U.S. Fourth Circuit Court of Appeals in June 2004. The Fourth Circuit heard oral argument on February 3, 2005. A decision is pending. Based on the current rulings by the trial court, Duke Energy does not believe the outcome of this matter will have a material adverse effect on its consolidated results of operations, cash flows or financial position. Subsequent rulings by the appellate court could significantly affect the outcome.

*Western Energy Litigation.* Since 2000, plaintiffs have filed 45 lawsuits in four western states against Duke Energy affiliates, current and former Duke Energy executives, and other energy companies. Most of the suits seek class-action certification on behalf of electricity and/or natural gas purchasers. The plaintiffs allege that the defendants manipulated the electricity and/or natural gas markets in violation of state and/or federal antitrust, unfair business practices and other laws. Plaintiffs in some of the cases further allege that such activities, including engaging in "round trip" trades, providing false information to natural gas trade publications and unlawfully exchanging information resulted in artificially high energy prices. Plaintiffs seek aggregate damages or restitution of billions of dollars from the defendants.

- To date, one suit has been voluntarily dismissed by plaintiffs. Ten suits have been dismissed on filed rate and federal preemption grounds. The U.S. Ninth Circuit Court of Appeals has affirmed the dismissals of eight of these ten lawsuits. The plaintiff in one of the dismissed actions affirmed by the Ninth Circuit has petitioned the U.S. Supreme Court for certiorari and that court has invited the U.S. Solicitor General to give the United States' views on whether certiorari should be granted. The plaintiffs in two of the ten dismissed actions to date have not filed appeals.
- In July 2004, Duke Energy reached an agreement in principle resolving the class-action litigation (the Western Power Class Action) involving the purchase of electricity filed on behalf of ratepayers and other electricity consumers in California, Washington, Oregon, Utah and Idaho. This agreement (the California Settlement) is part of a more comprehensive settlement involving FERC refunds and

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other proceedings. The class-action provisions of the California Settlement are subject to court approval. The California Settlement is addressed in more detail in the "Western Energy Regulatory Matters and Investigations" section below.

- Suits filed on behalf of electricity ratepayers in other western states, on behalf of entities that purchased electricity directly from a generator and on behalf of natural gas purchasers, remain pending. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with these lawsuits, but Duke Energy does not presently believe the outcome of these matters will have a material adverse effect on its consolidated results of operations, cash flows or financial position.

Separately, in 2003, Pacific Gas and Electric Company (PG&E) initiated arbitration proceedings regarding disputes with DETM relating to amounts owed in connection with the termination of a bilateral power contract between the parties in early 2001. PG&E sought in excess of $25 million from DETM pursuant to a disputed "true-up" agreement between the parties. The PG&E true-up dispute was resolved in connection with the California Settlement.

In 2002, Southern California Edison Company (SCE) initiated arbitration proceedings regarding disputes with DETM relating to amounts owed in connection with the termination of bilateral power contracts between the parties in early 2001. SCE disputes DETM's termination calculation and seeks in excess of $90 million. This dispute is not resolved in the California Settlement. Based on the level of damages claimed by the plaintiff and Duke Energy's assessment of possible outcomes in this matter, Duke Energy does not expect that the resolution of this matter will have a material adverse effect on its consolidated results of operations, cash flows or financial position.

*Western Energy Regulatory Matters and Investigations.* Duke has been the subject, along with other energy suppliers and producers, of several investigations and regulatory proceedings at the state and federal levels that are looking into the causes of high wholesale electricity prices in the western United States during 2000 and 2001. Duke Energy has resolved these issues, which are described in detail below, through the California Settlement.

- In FERC refund proceedings, the FERC ordered some sellers, including DETM, to refund, or to offset against outstanding accounts receivable, amounts billed for electricity sales in excess of a FERC-established proxy price. In 2002, the presiding administrative law judge in the FERC refund proceedings issued preliminary estimates that indicated DETM had refund liability of approximately $95 million. The FERC issued staff recommendations and an order in 2003 that modified the prior refund methodology by changing the gas proxy price used in the refund calculation. Platts, an energy industry publication, reported that a FERC spokesman announced that the methodology change could increase the total aggregate refund amount for all generators from $1.8 billion to at least $3.3 billion.
- In 2003, the FERC issued an Order to Show Cause concerning "Enron-type gaming behavior," and a companion order requiring suppliers, including DETM, to justify bids in the California Independent System Operator and the California Power Exchange markets made above the level of $250 per megawatt hour from May 1, 2000 through October 1, 2000. Later in 2003, the FERC Staff and Duke Energy announced two agreements to resolve all matters at issue in both of those orders. Duke Energy agreed to pay up to $4.59 million to benefit California and western electricity consumers, pending final approval by the FERC. The FERC approved the agreement involving bidding practices and rejected objections to the agreement. The objectors sought review of the FERC's ruling on this agreement from the U.S. Ninth Circuit Court of Appeals. In April 2004, the administrative law judge reviewing the remaining agreement approved the settlement and rejected the objections. FERC approved the second agreement and made findings that set Duke Energy's settlement amount with respect to both agreements at approximately $3 million, payment of which has been credited towards the California Settlement payment amount. The challenges to the two agreements are resolved through the California Settlement.
- At the state level, the California Public Utilities Commission (CPUC), a California State Senate Select Committee, the California Attorney General (with participation by the Attorneys General of Washington and Oregon) and the San Diego District Attorney have conducted formal and informal investigations involving Duke Energy regarding the California energy markets, including review of alleged manipulation of energy prices. In addition, the U.S. Attorney's Office in San Francisco served a grand jury subpoena on Duke Energy in 2002 seeking information relating to possible manipulation of the California electricity markets, including potential antitrust violations. All investigations (the State Civil Investigations), other than criminal investigations are resolved through the California Settlement. Duke Energy does not believe the outcome of any remaining criminal investigation will have a material adverse effect on its consolidated results of operations, cash flows or financial position.

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In July 2004, Duke Energy reached an agreement in principle with the FERC, the State of California and other in- and out-of-state participants to settle the FERC refund proceedings and other significant litigation related to the western energy markets during 2000-2001 described above. The class action portion of the settlement is subject to court approval, but FERC approved all remaining provisions of the settlement in December 2004. As part of the agreement, Duke Energy agreed to provide approximately $208 million in cash and credits to various parties involved in the settlement. The parties agreed to forgo all claims relating to refunds or other monetary damages for sales of electricity during the settlement period (January 1, 2000 through June 20, 2001), and claims alleging Duke Energy received unjust or unreasonable rates for the sale of electricity during the settlement period. The settlement resolved, among other matters:

- All western refund proceedings pending before the FERC
- The State Civil Investigations
- The Western Power Class Action
- Natural gas price issues raised by the California attorney general, PG&E, SCE and San Diego Gas & Electric Company

Duke Energy recorded an approximate $105 million pre-tax charge in the second quarter of 2004 at DENA to reflect the settlement agreement. This charge was recorded in Operation, Maintenance and Other on the Consolidated Statements of Operations. In December 2004, Duke Energy tendered all of the settlement proceeds except for $7 million relating to the class-action settlement. This remaining amount, which is fully reserved, will be paid upon court approval of the class-action settlement.

In Lockyer v. FERC, the U.S. Ninth Circuit Court of Appeals ruled in September 2004 that while FERC's authorization of market based rate tariffs complied with the Federal Power Act, the failure by sellers of electricity to file appropriate quarterly reports provides the FERC with authority to award refunds relating to the period prior to October 2000. The court declined to order refunds requested by the State of California but remanded the case to the FERC for further proceedings consistent with its opinion. The California Settlement resolves refund issues relating to the post-October 2000 refund period as well as the pre-October 2000 period that was at issue in the Lockyer case. While the Lockyer ruling does not affect Duke Energy's settlement, the decision could give rise to potential refund liability at the FERC for market-based rate sellers generally, including Duke Energy affiliates, to the extent quarterly reports filed by those entities are incomplete or inaccurate.

*Trading Related Litigation.* Beginning in 2002, 17 shareholder class-action lawsuits were filed against Duke Energy: 13 in the U.S. District Court for the Southern District of New York and four in the U.S. District Court for the Western District of North Carolina. These lawsuits arose out of allegations that Duke Energy improperly engaged in "round trip" trades which resulted in an alleged overstatement of revenues over a three-year period. By late 2003, the two federal courts had dismissed all 17 lawsuits. Plaintiffs in the New York cases appealed the dismissal order to the U.S. Second Circuit Court of Appeals. On November 15, 2004, appellate court affirmed the trial court's dismissal of the New York cases.

By letter dated April 16, 2004, Duke Energy received notice that a shareholder reactivated a litigation demand sent to Duke Energy in 2002. Arising out of the same issues raised in the dismissed shareholder lawsuits, the notice stated that the shareholder intended to initiate derivative shareholder litigation within 90 days from the date of the letter if Duke Energy did not initiate litigation within the stated timeframe. Duke Energy's Board of Directors appointed a special committee to review the demand. The committee determined that there are no grounds supporting the allegations made in the derivative demand to commence or maintain an action on behalf of Duke Energy against the individuals named in the derivative demand, and that, accordingly, it would not be in the best interests of Duke Energy to bring such claims. By letter dated January 21, 2005, another shareholder reactivated a 2002 litigation demand. The reactivated demand arises out of the same issues that were raised in the April 16 reactivated demand as well as matters that were the subject of the California Settlement. The special committee is reviewing this second demand.

Commencing August 2003, plaintiffs filed three class-action lawsuits in the U.S. District Court for the Southern District of New York on behalf of entities who bought and sold natural gas futures and options contracts on the NYMEX during the years 2000 through 2002. DETM, along with numerous other entities, is named as a defendant. The cases claim that the defendants violated the Commodity Exchange Act by reporting false and misleading trading information to trade publications, resulting in monetary losses to the plaintiffs. Plaintiffs seek class action certification, unspecified damages and other relief. On September 24, 2004, the court denied a motion to dismiss the plaintiffs' claims filed on behalf of DETM and other defendants. On January 25, 2005, the plaintiffs filed a motion for class certification; defendants are opposing the motion which has not yet been scheduled for hearing. Duke Energy is unable to express an opinion regarding the probable outcome of these matters at this time.

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On January 28, 2005, four plaintiffs filed suit in Tennessee Chancery Court against Duke Energy affiliates and other energy companies seeking class action certification on behalf of indirect purchasers of natural gas who allege that they have been harmed by defendants' manipulation of the natural gas markets by various means, including providing false information to natural gas trade publications and unlawfully exchanging information, resulting in artificially high natural gas prices paid by plaintiffs in the State of Tennessee. Alleging that defendants violated state antitrust laws and other laws, plaintiffs seek unspecified damages and other relief. Duke Energy is unable to express an opinion regarding the probable outcome of these matters at this time.

*Trading Related Investigations.* In 2002 and 2003, Duke Energy responded to information requests and subpoenas from the SEC and to grand jury subpoenas issued by the U.S. Attorney's office in Houston, Texas. The information requests and subpoenas sought documents and information related to trading activities, including so-called "round-trip" trading. Duke Energy received notice in 2002 that the SEC formalized its trading-related investigation and is cooperating with the SEC. Based on discussions with the SEC staff in March 2005, Duke Energy anticipates making an offer of settlement to resolve the issues that are the subject of the SEC's investigation regarding conduct that occurred in 2000 through June 2002. The terms of the anticipated offer would include issuance of an order to Duke Energy to cease and desist from violating internal controls and books and records requirements under Sections 13(b)(2)(A) and 13(b)(2)(B) of the Securities Exchange Act of 1934, but would not include a penalty or finding of fraud. Duke Energy has taken actions to remediate the issues that have been raised in the SEC's investigation regarding internal controls. Any offer of settlement Duke Energy makes would be subject to approval by the SEC.

In April 2004, the Houston-based federal grand jury issued indictments for three former employees of DETMI Management Inc. (DETMI), which is one of two members of DETM. The indictments state that the employees "did knowingly devise, intend to devise, and participate in a scheme to defraud and to obtain money and property from Duke Energy by means of materially false and fraudulent pretenses, representations and promises, and material omissions, and to deprive Duke Energy and its shareholders of the intangible right to the honest services of employees of Duke Energy." They further state that the alleged conduct was purportedly motivated, in part, by a desire to increase individual bonuses. Statements made by the U.S. Attorney's office characterized Duke Energy as a victim in this activity and commended Duke Energy for its cooperation with the investigation. The alleged conduct was identified in the spring and summer of 2002 and was related to DETM's Eastern Region trading activities. In 2002, Duke Energy recorded the appropriate financial adjustments associated with the cited activities, and did not consider the financial effect to be material. In February 2005, one of the 3 indicted former DETMI employees pled guilty to a books and records violation, and a superseding indictment was filed against the other two former employees, providing more detail and adding an allegation that the former employees intentionally circumvented internal accounting controls.

In February 2004, Duke Energy received a request for information from the U.S. Attorney's office in Houston focused on the natural gas price reporting activity of a former DETM trader. Duke Energy has cooperated with the government in this investigation and is unable to express an opinion regarding the probable outcome at this time.

In February 2005, the Commodity Futures Trading Commission initiated a civil action against a former DETM trader asserting charges of delivering false reports and attempted manipulation of prices through index price reporting. Duke Energy is not named in this action.

*Sonatrach/Sonatrading Arbitration.* Duke Energy LNG Sales Inc. (Duke LNG) claims in an arbitration commenced in January 2001 in London that Sonatrach, the Algerian state-owned energy company, together with its subsidiary, Sonatrading Amsterdam B.V. (Sonatrading), breached their shipping obligations under a liquefied natural gas (LNG) purchase agreement and related transportation agreements (the LNG Agreements) relating to Duke LNG's purchase of LNG from Algeria and its transportation by LNG tanker to Lake Charles, Louisiana. Duke LNG seeks damages of approximately $27 million. Sonatrading and Sonatrach claim that Duke LNG repudiated the LNG Agreements by allegedly failing to diligently perform LNG marketing obligations. Sonatrading and Sonatrach seek damages in the amount of approximately $600 million. In 2003, an arbitration panel issued a Partial Award on liability issues, finding that Sonatrach and Sonatrading breached their obligations to provide shipping. The panel also found that Duke LNG breached the LNG Purchase Agreement by failing to perform marketing obligations. The hearing on damages issues is scheduled to commence in September 2005.

*Citrus Trading Corporation (Citrus) Litigation.* In conjunction with the Sonatrach LNG Agreements, Duke LNG entered into a natural gas purchase contract (the Citrus Agreement) with Citrus. Citrus filed a lawsuit in March 2003 in the U.S. District Court for the Southern District of Texas against Duke LNG and PanEnergy Corp alleging that Duke LNG breached the Citrus Agreement by failing to provide sufficient volumes of gas to Citrus. Duke LNG contends that Sonatrach caused Duke LNG to experience a loss of LNG supply that affected Duke LNG's obligations and termination rights under the Citrus Agreement. Citrus seeks monetary damages and a judicial determination that Duke LNG did not experience such a loss. After Citrus filed its lawsuit, Duke LNG terminated the Citrus Agreement and filed a

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counterclaim asserting that Citrus had breached the agreement by, among other things, failing to provide sufficient security under a letter of credit for the gas transactions. Citrus denies that Duke LNG had the right to terminate the agreement and contends that Duke LNG's termination of the agreement was itself a breach, entitling Citrus to terminate the agreement and recover damages in the amount of approximately $187 million. Cross motions for partial summary judgment regarding the letter of credit issue have been filed and are pending. No trial date has been set. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with the Sonatrach and Citrus matters.

*ExxonMobil Disputes.* In April 2004, Mobil Natural Gas, Inc. (MNGI) and 3946231 Canada, Inc. (3946231, and collectively with MNGI, ExxonMobil) filed a Demand for Arbitration against Duke Energy, DETMI, DTMSI Management Ltd. (DTMSI) and other affiliates of Duke Energy. MNGI and DETMI are the sole members of DETM. DTMSI and 3946231 are the sole beneficial owners of Duke Energy Marketing Limited Partnership (DEMLP, and with DETM, the Ventures). Among other allegations, ExxonMobil alleges that DETMI and DTMSI engaged in wrongful actions relating to affiliate trading, payment of service fees, expense allocations and distribution of earnings in breach of agreements and fiduciary duties relating to the Ventures. ExxonMobil seeks to recover actual damages, plus attorneys' fees and exemplary damages; aggregate damages were not specified in the arbitration demand. Duke Energy denies these allegations, and has filed counterclaims asserting that ExxonMobil breached its Ventures obligations and other contractual obligations. A hearing in this arbitration has been tentatively scheduled for January 2006. In August 2004, DEMLP initiated arbitration proceedings in Canada against certain ExxonMobil entities asserting that those entities wrongfully terminated two gas supply agreements with the Ventures and wrongfully failed to assume certain related gas supply agreement with other parties. A hearing in the Canadian arbitration proceeding has been scheduled to begin in August 2005. These matters are in very early stages, and it is not possible to predict with certainty the damages that might be incurred by Duke Energy or any of its affiliates as a result of these matters.

*Asbestos-related Injuries and Damages Claims.* Duke Energy has experienced numerous claims relating to damages for personal injuries alleged to have arisen from the exposure to or use of asbestos in connection with construction and maintenance activities conducted by Duke Power on its electric generation plants during the 1960s and 1970s. Duke Energy has third-party insurance to cover losses related to these asbestos-related injuries and damages above a certain aggregate deductible. The insurance policy, including the policy deductible, provides for coverage to Duke Energy up to an aggregate of $1.6 billion. Probable insurance recoveries related to this policy are classified in the Consolidated Balance Sheets as Other within noncurrent assets. Amounts recognized as reserves in the Consolidated Balance Sheets are classified in Other Deferred Credits and Other Liabilities and Other Current Liabilities and are based upon Duke Energy's best estimate of the probable liability for future asbestos claims. These reserves are based upon current estimates and are subject to uncertainty. Factors such as the frequency and magnitude of future claims could change the current estimates of the related reserves and claims for recoveries reflected in the accompanying Consolidated Financial Statements. However, management of Duke Energy does not currently anticipate that any changes to these estimates will have any material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

*Other Litigation and Legal Proceedings.* Duke Energy and its subsidiaries are involved in other legal, tax and regulatory proceedings in various forums regarding performance, contracts, royalty disputes, mismeasurement and mispayment claims (some of which are brought as class actions), and other matters arising in the ordinary course of business, some of which involve substantial amounts. Management believes that the final disposition of these proceedings will have no material adverse effect on consolidated results of operations, cash flows or financial position.

Duke Energy has exposure to certain legal matters that are described herein. As of December 31, 2004, Duke Energy has recorded reserves of approximately $1.4 billion for these proceedings and exposures. Duke Energy has insurance coverage for certain of these losses incurred. As of December 31, 2004, Duke Energy has recognized approximately $1.0 billion of probable insurance recoveries related to these losses. These reserves represent management's best estimate of probable loss as defined by SFAS No. 5, "Accounting for Contingencies."

Duke Energy expenses legal costs related to the defense of loss contingencies as incurred.

**Other Commitments and Contingencies**

As part of its normal business, Duke Energy is a party to various financial guarantees, performance guarantees and other contractual commitments to extend guarantees of credit and other assistance to various subsidiaries, investees and other third parties. These arrangements are largely entered into by Duke Capital. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of Duke Energy or Duke Capital having to honor its

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contingencies is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. Duke Energy would record a reserve if events occurred that required that one be established. (For further information see Note 18.)

In addition, Duke Energy enters into various fixed-price, non-cancelable commitments to purchase or sell power (tolling arrangements or power purchase contracts), take-or-pay arrangements, transportation or throughput agreements and other contracts that may or may not be recognized on the Consolidated Balance Sheets. Some of these arrangements may be recognized at market value on the Consolidated Balance Sheets as trading contracts or qualifying hedge positions included in Unrealized Gains or Losses on Mark-to-Market and Hedging Transactions.

**Operating and Capital Lease Commitments**

Duke Energy leases assets in several areas of its operations. Consolidated rental expense for operating leases was $124 million in 2004, $133 million in 2003 and $133 million in 2002, and included in Operation, Maintenance and Other on the Consolidated Statements of Operations. Amortization of assets recorded under capital leases was included in Depreciation and Amortization on the Consolidated Statements of Operations. The following is a summary of future minimum lease payments under operating leases, which at inception had a noncancelable term of more than one year, and capital leases as of December 31, 2004:

| | Operating Leases | Capital Leases |
|---|---|---|
| | (in millions) | |
| 2005 | $ 94 | $119 |
| 2006 | 78 | 14 |
| 2007 | 59 | 14 |
| 2008 | 49 | 15 |
| 2009 | 43 | 15 |
| Thereafter | 207 | 18 |
| Total future minimum lease payments | $530 | $195 |

## 18. Guarantees and Indemnifications

Duke Energy and its subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Duke Energy enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party.

**Mixed Oxide (MOX) Guarantees.** DCS is the prime contractor to the DOE under a contract (the Prime Contract) pursuant to which DCS will design, construct, operate and deactivate a domestic MOX fuel fabrication facility (the MOX FFF) and provide for the irradiation of the MOX fuel. The domestic MOX fuel project was prompted by an agreement between the United States and the Russian Federation to dispose of excess plutonium in their respective nuclear weapons programs by fabricating MOX fuel and irradiating such MOX fuel in commercial nuclear reactors. As of December 31, 2004, Duke Energy, through its indirect wholly owned subsidiary, Duke Project Services Group Inc. (DPSG), held a 40% ownership interest in DCS.

The Prime Contract consists of a "Base Contract" phase and successive option phases. The DOE has the right to extend the term of the Prime Contract to cover the option phases on a sequential basis, subject to DCS and the DOE reaching agreement, through good-faith negotiations on certain remaining open terms applying to each of the option phases. As of December 31, 2004, DCS' performance obligations under the Prime Contract included only the Base Contract phase and the first option phase covering mission reactor modifications.

DPSG and the other owners of DCS have issued a guarantee to the DOE which, in conjunction with the applicable guarantee provisions (as clarified by an April 2004 amendment) in the Prime Contract (collectively, the DOE Guarantee), obligates the owners of DCS to jointly and severally guarantee to the DOE that the owners of DCS will reimburse the DOE (in the event that DCS fails to provide such reimbursement) for any payments made by the DOE to DCS pursuant to the Prime Contract that DCS expends on costs that are not "allowable" under certain applicable federal acquisition regulations. DPSG has recourse to the other owners of DCS for any amounts paid under the DOE Guarantee in excess of its proportional ownership percentage of DCS. Although the DOE Guarantee does not provide for a specific limitation on a guarantor's reimbursement obligations, Duke Energy estimates that the maximum potential amount of future

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payments DPSG could be required to make under the DOE Guarantee is immaterial. As of December 31, 2004, Duke Energy had no liabilities recorded on its Consolidated Balance Sheets for the DOE Guarantee due to the immaterial amount of the estimated fair value of such guarantee.

In connection with the Prime Contract, Duke Energy, through its Duke Power franchised electric business, has entered into a subcontract with DCS (the Duke Power Subcontract) pursuant to which Duke Power will prepare its McGuire and Catawba nuclear reactors (the Mission Reactors) for use of the MOX fuel, and which also includes terms and conditions applicable to Duke Power's purchase of MOX fuel produced at the MOX FFF for use in the Mission Reactors. The Duke Power Subcontract consists of a "Base Subcontract" phase and successive option phases. DCS has the right to extend the term of the Duke Power Subcontract to cover the option phases on a sequential basis, subject to Duke Power and DCS reaching agreement, through good-faith negotiations on certain remaining open terms applying to each of the option phases. As of December 31, 2004, DCS' performance obligations under the Duke Power Subcontract included only the Base Subcontract phase and the first option phase covering mission reactor modifications.

DPSG and the other owners of DCS have issued a guarantee to Duke Power (the Duke Power Guarantee) pursuant to which the owners of DCS jointly and severally guarantee to Duke Power all of DCS' obligations under the Duke Power Subcontract or any other agreement between DCS and Duke Power implementing the Prime Contract. DPSG has recourse to the other owners of DCS for any amounts paid under the Duke Power Guarantee in excess of its proportional ownership percentage of DCS. Even though the Duke Power Guarantee does not provide for a specific limitation on a guarantor's guarantee obligations, it does provide that any liability of such guarantor under the Duke Power Guarantee is directly related to and limited by the terms and conditions in the Duke Power Subcontract and any other agreements between Duke Power and DCS implementing the Duke Power Subcontract. Duke Energy is unable to estimate the maximum potential amount of future payments DPSG could be required to make under the Duke Power Guarantee due to the uncertainty of whether:

- DCS will exercise its options under the Duke Power Subcontract, which will depend upon whether the DOE will exercise its options under the Prime Contract, which, in turn, will depend on whether the U.S. Congress will authorize funding for DCS's work under the Prime Contract, and
- the parties to the Prime Contract and the Duke Power Subcontract, respectively, will reach agreement on the remaining open terms for each option phase under the contracts, and if so, what the terms and conditions might be.

Duke Energy has not recorded on its Consolidated Balance Sheets any liability for the potential exposure under the Duke Power Guarantee per FIN 45, because DPSG and Duke Power are under common control.

**Other Guarantees and Indemnifications.** Duke Capital has issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities. The maximum potential amount of future payments Duke Capital could have been required to make under these performance guarantees as of December 31, 2004 was approximately $1.1 billion. Of this amount, approximately $660 million relates to guarantees of the payment and performance of less than wholly owned consolidated entities. Approximately $60 million of the performance guarantees expire between 2005 and 2007, with the remaining performance guarantees expiring after 2008 or having no contractual expiration. Additionally, Duke Capital has issued joint and several guarantees to some of the D/FD project owners, guaranteeing the performance of D/FD under its engineering, procurement and construction contracts and other contractual commitments. These guarantees have no contractual expiration and no stated maximum amount of future payments that Duke Capital could be required to make. Additionally, Fluor Enterprises Inc., as 50% owner in D/FD, has issued similar joint and several guarantees to the same D/FD project owners. In accordance with the D/FD partnership agreement, each of the partners is responsible for 50% of any payments to be made under those guarantees.

Westcoast has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method projects, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of an unconsolidated entity to make payment under some of its contractual obligations, such as debt, purchase contracts and leases. The maximum potential amount of future payments Westcoast could have been required to make under those performance guarantees as of December 31, 2004 was approximately $60 million. Of those guarantees, approximately $10 million expire in 2006, with the remainder having no contractual expiration.

Duke Capital uses bank-issued stand-by letters of credit to secure the performance of non-wholly owned entities to a third party or customer. Under these arrangements, Duke Capital has payment obligations to the issuing bank which are triggered by a draw by the third party or customer due to the failure of the non-wholly owned entity to perform according to the terms of its underlying contract. The

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maximum potential amount of future payments Duke Capital could have been required to make under these letters of credit as of December 31, 2004 was approximately $400 million. Of this amount, approximately $350 million relates to letters of credit issued on behalf of less than wholly owned consolidated entities. Substantially all of these letters of credit expire in 2005.

Duke Capital has guaranteed certain issuers of surety bonds, obligating itself to make payment upon the failure of a non-wholly owned entity to honor its obligations to a third party. As of December 31, 2004, Duke Capital had guaranteed approximately $80 million of outstanding surety bonds related to obligations of non-wholly owned entities. The majority of these bonds expire in various amounts between 2005 and 2006. Of this amount, approximately $10 million relates to obligations of less than wholly owned consolidated entities.

Natural Gas Transmission and International Energy have issued guarantees of debt and performance guarantees associated with non-consolidated entities and less than wholly-owned entities. If such entities were to default on payments or performance, Natural Gas Transmission or International Energy would be required under the guarantees to make payment on the obligation of the less than wholly-owned entity. As of December 31, 2004, Natural Gas Transmission was the guarantor of approximately $15 million of debt at Westcoast associated with less than wholly owned entities, with approximately $8 million expiring in 2009 and the remainder having no contractual expiration. International Energy was the guarantor of approximately $70 million of performance guarantees associated with less than wholly-owned entities, with substantially all of the guarantees expiring in 2005.

Duke Energy has issued guarantees to customers or other third parties related to the payment or performance obligations of certain entities that were previously wholly owned by Duke Energy but which have been sold to third parties, such as DukeSolutions and DE&S. These guarantees are primarily related to payment of lease obligations, debt obligations, and performance guarantees related to goods and services provided. Duke Energy has received back-to-back indemnification from the buyer of DE&S indemnifying Duke Energy for any amounts paid by Duke Energy related to the DE&S guarantees. Duke Energy also received indemnification from the buyer of DukeSolutions for the first $2.5 million paid by Duke Energy related to the DukeSolutions guarantees. Further, Duke Energy granted indemnification to the buyer of Duke Solutions with respect to losses arising under some energy services agreements retained by DukeSolutions after the sale, provided that the buyer agreed to bear 100% of the performance risk and 50% of any other risk up to an aggregate maximum of $2.5 million (less any amounts paid by the buyer under the indemnity discussed above). Additionally, for certain performance guarantees, Duke Energy has recourse to subcontractors involved in providing services to a customer. These guarantees have various terms ranging from 2004 to 2019, with others having no specific term. Duke Energy is unable to estimate the total maximum potential amount of future payments under these guarantees, since some of the underlying agreements have no limits on potential liability.

Additionally, in August 2004, Duke Capital guaranteed in favor of a bank the repayment of any draws under a $120 million letter of credit issued by such bank to Georgia Power Company, which expires in 2005, related to the obligation of a KGen subsidiary under a seven year power sales agreement, commencing in May 2005, as discussed in Note 2. Duke Capital will be required to ensure reissuance of this letter of credit or issue similar credit support until the power sales agreement expires in 2012. Duke Energy will operate the Murray facility under an operation and maintenance agreement with the KGen subsidiary. As a result, the guarantee has an immaterial fair value. Further, KGen has agreed to indemnify Duke Energy for any payments made by Duke Energy with respect to the $120 million letter of credit.

Duke Energy has entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time, depending on the nature of the claim. Duke Energy's maximum potential exposure under these indemnification agreements can range from a specified to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Duke Energy is unable to estimate the total maximum potential amount of future payments under these indemnification agreements due to several factors, including uncertainty as to whether claims will be made.

As of December 31, 2004, the amounts recorded for the guarantees and indemnifications mentioned above are immaterial, both individually and in the aggregate.

## 19. Earnings Per Share (EPS)

Basic earnings per share are computed by dividing earnings available for common stockholders by the weighted-average number of common shares outstanding during the period. Diluted earnings per share are computed by dividing earnings available for common

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stockholders by the diluted weighted-average number of common shares outstanding each period. Diluted earnings per share reflect the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options, stock-based performance unit awards, contingently convertible debt and phantom stock awards, were exercised or converted into common stock.

The following tables illustrate Duke Energy's basic and diluted EPS Calculations and reconciles the weighted-average number of common shares outstanding to the diluted weighted-average number of common shares outstanding for 2004, 2003 and 2002.

The following tables illustrate Duke Energy's basic and diluted EPS calculations and reconciles the weighted-average number of common shares outstanding to the diluted weighted-average number of common shares outstanding for 2004, 2003, and 2002.

| (in millions, except per share data) | Income (Loss) | Average Shares | EPS |
|---|---|---|---|
| **2004** | | | |
| Income from continuing operations | $ 1,232 | | |
| Less: Dividends and premiums on redemption of preferred and preference stock | (9) | | |
| Income from continuing operations—basic | $ 1,223 | 931 | $ 1.31 |
| Effect of dilutive securities: | | | |
| Stock options, phantom, performance and restricted stock | | 2 | |
| Contingently convertible bond | 8 | 33 | |
| Income from continuing operations—diluted | $ 1,231 | 966 | $ 1.27 |
| **2003**(a) | | | |
| Loss from continuing operations | $(1,003) | | |
| Less: Dividends and premiums on redemption of preferred and preference stock | (15) | | |
| Loss from continuing operations—basic and diluted | $(1,018) | 903 | $(1.13) |
| **2002** | | | |
| Income from continuing operations | $ 1,295 | | |
| Less: Dividends and premiums on redemption of preferred and preference stock | (13) | | |
| Income from continuing operations—basic | $ 1,282 | 836 | $ 1.53 |
| Effect of dilutive securities: | | | |
| Stock options, phantom, performance and restricted stock | — | 2 | |
| Income from continuing operations—diluted | $ 1,282 | 838 | $ 1.53 |

(a) A separate diluted EPS calculation is not required as Duke Energy experienced a loss from continuing operations in 2003.

The increase in weighted-average shares outstanding at December 31, 2004 compared to December 31, 2003 was due primarily to the issuance of 41.1 million shares associated with the settlement of the forward purchase contract component of Duke Energy's Equity Units in May and November 2004. The increase in diluted weighted-average shares outstanding at December 31, 2004 compared to December 31, 2003 was primarily due to Duke Energy adopting the final consensus on EITF Issue No. 04-8 which required the inclusion of 32.6 million potential common shares related to Duke Energy's $770 million contingently convertible debt issuance. (See Note 15)

Options, restricted stock, performance and phantom stock awards to purchase approximately 23.2 million shares as of December 31, 2004 and 31.4 million shares at December 31, 2002 were not included in "potential dilution for the period" in the above table because either the option exercise prices were greater than the average market price of the common shares during those periods, or performance measures related to the awards had not yet been met. As discussed in note (a) above, 55.6 million shares at December 31, 2003 were excluded in the December 31, 2003 diluted weighted-average share calculation.

## 20. Stock-Based Compensation

Duke Energy's 1998 Long-term Incentive Plan, as amended (the 1998 Plan), reserved 60 million shares of common stock for awards to employees and outside directors. Under the 1998 Plan, the exercise price of each option granted cannot be less than the market price

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**Notes To Consolidated Financial Statements—(Continued)**

of Duke Energy's common stock on the date of grant and the maximum option term is 10 years. The vesting periods range from immediate to five years.

Upon the acquisition of Westcoast, Duke Energy converted all stock options outstanding under the 1989 Westcoast Long-term Incentive Share Option Plan to Duke Energy Corporation stock options. Certain of these options also provide for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right. The exercise price of these options equals the market price on the date of grant and the maximum option term is 10 years. The vesting periods range from immediate to four years.

**Stock Option Activity**

| | Options (in thousands) | Weighted-Average Exercise Price |
|---|---|---|
| Outstanding at December 31, 2001 | 26,406 | $33 |
| Granted[a] | 9,406 | 34 |
| Exercised | (1,452) | 23 |
| Forfeited | (3,151) | 37 |
| Outstanding at December 31, 2002 | 31,209 | 34 |
| Granted | 8,248 | 15 |
| Exercised | (339) | 11 |
| Forfeited | (6,702) | 34 |
| Outstanding at December 31, 2003 | 32,416 | 29 |
| Exercised | (867) | 15 |
| Forfeited | (2,993) | 33 |
| Outstanding at December 31, 2004 | 28,556 | 29 |

(a) Includes 2,746 converted Westcoast stock options

**Stock Options at December 31, 2004**

| | Outstanding | | | Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Number (in thousands) | Weighted-Average Remaining Life (in years) | Weighted-Average Exercise Price | Number (in thousands) | Weighted-Average Exercise Price |
| $9 to $14 | 5,025 | 7.8 | $14 | 1,179 | $13 |
| $15 to $20 | 1,979 | 8.1 | 17 | 742 | 18 |
| $21 to $24 | 397 | 4.0 | 22 | 397 | 22 |
| $25 to $28 | 5,945 | 4.6 | 26 | 5,894 | 26 |
| $29 to $33 | 4,084 | 3.8 | 30 | 4,027 | 30 |
| $34 to $37 | 805 | 7.1 | 34 | 484 | 34 |
| $38 to $39 | 6,036 | 7.0 | 38 | 4,901 | 38 |
| > $39 | 4,285 | 6.0 | 43 | 4,171 | 43 |
| Total | 28,556 | 6.1 | | 21,795 | 32 |

On December 31, 2003, Duke Energy had 20.4 million exercisable options with a $32 weighted-average exercise price. On December 31, 2002, Duke Energy had 19.1 million exercisable options with a $32 weighted-average exercise price.

The weighted-average fair value per option granted was $4 for 2003 and $10 for 2002. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model. There were no options granted in 2004.

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**Notes To Consolidated Financial Statements—(Continued)**

**Weighted-Average Assumptions for Option-Pricing**

| | 2003 | 2002 |
|---|---|---|
| Stock dividend yield | 3.5% | 3.4% |
| Expected stock price volatility | 37.5% | 29.9% |
| Risk-free interest rates | 3.6% | 5.0% |
| Expected option lives | 7 years | 7 years |

The 1998 Plan allows for a maximum of twelve million shares of common stock to be issued under restricted stock awards, stock-based performance awards and phantom stock awards. Stock-based performance awards granted under the 1998 Plan vest over periods from three to seven years. Vesting can occur in three years, at the earliest if performance is met. Duke Energy awarded 1,584,840 shares (fair value of approximately $34 million at grant dates) in 2004 and 75,000 shares (fair value of approximately $2 million at grant dates) in 2003, and 16,000 shares (fair value of approximately $1 million at grant dates) in 2002. Compensation expense for the performance awards is charged to earnings over the vesting period and totaled $10 million in 2004, $3 million in 2003 and $4 million in 2002.

Phantom stock awards granted under the 1998 Plan vest over periods from one to five years. Duke Energy awarded 1,283,220 shares (fair value of approximately $27 million at grant dates) in 2004, 285,000 shares (fair value of approximately $5 million at grant dates) in 2003, and 54,430 shares (fair value of approximately $2 million at grant dates) in 2002. Compensation expense for the phantom awards is charged to earnings over the vesting period and totaled $14 million in 2004, $6 million in 2003 and $10 million in 2002.

Restricted stock awards granted under the 1998 Plan vest over periods from one to five years. Duke Energy awarded 169,160 shares (fair value of approximately $4 million at grant dates) in 2004, 19,897 shares (fair value of less than $1 million at grant dates) in 2003, and 14,260 shares (fair value of less than $1 million at grant dates) in 2002. Compensation expense for restricted awards is charged to earnings over the vesting period and totaled $1 million in 2004, $1 million in 2003 and $2 million in 2002.

Duke Energy's 1996 Stock Incentive Plan (the 1996 Plan) allowed four million shares of common stock for awards to employees. As of December 31, 2004, there are no more awards outstanding under the 1996 Plan. Duke Energy awarded no restricted shares in 2004, 2003 and 2002. Compensation expense for restricted awards is charged to earnings over the vesting period and totaled less than $1 million in 2004 and 2003 and $1 million in 2002. The 1996 Plan is not available for new awards.

## 21. Employee Benefit Plan

**Duke Energy U.S. Retirement Plan.** Duke Energy and its subsidiaries maintain a non-contributory defined benefit retirement plan. The plan covers most U.S. employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits.

Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants. Duke Energy made a voluntary contribution of $250 million to its defined benefit retirement plan in 2004 and $181 million in 2003. No contribution to the Duke Energy plan was made in 2002. Duke Energy does not anticipate making a contribution to the plan in 2005.

The net unrecognized transition asset, resulting from the implementation of accrual accounting, is amortized over approximately 20 years. Duke Energy determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over five years. Duke Energy uses a September 30 measurement date for its defined benefit retirement plan.

**Westcoast Canadian Retirement Plans.** The Westcoast benefit plans are reported separately due to actuarial assumption differences. Westcoast and its subsidiaries maintain contributory and non-contributory defined benefit (DB) and defined contribution (DC) retirement plans covering substantially all employees. The DB plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC plans, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings.

Westcoast's policy is to fund the DB plans on an actuarial basis and in accordance with Canadian pension standards legislation, in order to accumulate assets sufficient to meet benefits to be paid. Contributions to the DC plans are determined in accordance with the terms of the plan. Duke Energy made contributions to the Westcoast DB plans of approximately $28 million in 2004, $11 million in 2003, and $9 million in 2002. Duke Energy anticipates that it will make contributions of approximately $33 million to the Westcoast DB plans in

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**Notes To Consolidated Financial Statements—(Continued)**

2005. Duke Energy also made contributions to the DC plans of $3 million in 2004, $3 million in 2003, and $2 million in 2002. Duke Energy anticipates that it will make contributions to the DC plans of approximately $3 million in 2005.

The net unrecognized transition asset and actuarial gains and losses are amortized over the average remaining service period of the active employees. The average remaining service period of the active employees covered by the DB retirement plans is 13 years. Westcoast uses a September 30 measurement date for its plans.

***Components of Net Periodic Pension Costs***

| | Duke Energy U.S. | | | Westcoast | | |
|---|---|---|---|---|---|---|
| | For the Years Ended December 31, | | | | | |
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| | (in millions) | | | | | |
| Service cost benefit earned during the year | $ 64 | $ 70 | $ 69 | $ 8 | $ 7 | $ 6 |
| Interest cost on projected benefit obligation | 160 | 175 | 177 | 26 | 23 | 17 |
| Expected return on plan assets | (233) | (236) | (267) | (24) | (24) | (19) |
| Amortization of prior service cost | (2) | (3) | (3) | — | — | — |
| Amortization of net transition asset | (4) | (4) | (4) | — | — | — |
| Curtailment (gain) /loss | (1) | — | — | | 2 | — |
| Amortization of loss | 15 | — | — | 3 | — | — |
| Special termination benefit cost | — | — | 1 | 1 | 5 | — |
| Net periodic pension (income) / costs | $ (1) | $ 2 | $ (27) | $ 14 | $ 13 | $ 4 |

As required by SFAS No. 87 "Employers' Accounting for Pensions", Duke Energy amortized actuarial losses in its U.S. plan of $15 million. The amortization of these losses in 2004 is primarily attributable to lower than expected asset returns over the past five years.

**Reconciliation of Funded Status to Net Amount Recognized**

| | Duke Energy U.S. | | Westcoast | |
|---|---|---|---|---|
| | For the Years Ended December 31, | | | |
| | 2004 | 2003 | 2004 | 2003 |
| | (in millions) | | | |
| **Change in Projected Benefit Obligation** | | | | |
| Obligation at prior measurement date | $2,763 | $2,671 | $434 | $334 |
| Service cost | 64 | 70 | 8 | 7 |
| Interest cost | 160 | 175 | 26 | 23 |
| Actuarial losses / (gains) | 17 | 60 | (8) | 27 |
| Plan amendments | — | 4 | 6 | — |
| Participant contributions | — | — | 2 | 2 |
| Benefits paid | (298) | (217) | (28) | (25) |
| Curtailment | (13) | — | — | 2 |
| Divestiture | — | — | — | (10) |
| Special termination benefits | — | — | 7 | — |
| Foreign currency impact | — | — | 33 | 74 |
| Obligation at measurement date | $2,693 | $2,763 | $480 | $434 |

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**Notes To Consolidated Financial Statements—(Continued)**

| | Duke Energy U.S. | | Westcoast | |
|---|---|---|---|---|
| | For the Years Ended December 31, | | | |
| | 2004 | 2003 | 2004 | 2003 |
| | (in millions) | | | |
| **Change in Fair Value of Plan Assets** | | | | |
| Plan assets at prior measurement date | $2,477 | $2,120 | $ 324 | $ 255 |
| Actual return on plan assets | 298 | 393 | 29 | 35 |
| Benefits paid | (298) | (217) | (28) | (25) |
| Employer contributions | — | 181 | 12 | 11 |
| Plan participants' contributions | — | — | 2 | 2 |
| Divestiture | — | — | — | (9) |
| Foreign currency impact | — | — | 23 | 55 |
| Plan assets at measurement date | $2,477 | $2,477 | $ 362 | $ 324 |
| Funded status | $ (216) | $ (286) | $(118) | $(110) |
| Unrecognized net experience loss | 740 | 816 | 68 | 79 |
| Unrecognized prior service cost | (4) | (7) | 9 | — |
| Special termination benefits | — | — | — | (5) |
| Unrecognized net transition asset | — | (4) | — | — |
| Contributions made after measurement date | 250 | — | 19 | 3 |
| Net amount recognized | $ 770 | $ 519 | $ (22) | $ (33) |

For the Duke Energy U.S. plan, the accumulated benefit obligation was $2,607 million at September 30, 2004 and $2,646 million at September 30, 2003.

For Westcoast, the accumulated benefit obligation was $435 million at September 30, 2004 and $394 million at September 30, 2003.

**Amounts Recognized in the Consolidated Balance Sheets Consist of:**

| | Duke Energy U.S. | | Westcoast | |
|---|---|---|---|---|
| | For the Year Ended December 31, | | | |
| | 2004 | 2003 | 2004 | 2003 |
| | (in millions) | | | |
| Accrued pension liability | $ — | $(170) | $(53) | $(70) |
| Pre-funded pension costs | 120 | — | — | — |
| Deferred income tax asset | 254 | 270 | 13 | 13 |
| Accumulated other comprehensive income | 396 | 419 | 18 | 21 |
| Net amount recognized | $770 | $ 519 | $(22) | $(36) |

**Additional Information:**

| | Duke Energy U.S. | | Westcoast | |
|---|---|---|---|---|
| | For the Years Ended December 31, | | | |
| | 2004 | 2003 | 2004 | 2003 |
| | (in millions) | | | |
| Increase/(Decrease) in minimum liability included in other comprehensive income, net of tax | $(23) | $(51) | $(3) | $7 |

DUKE ENERGY CORPORATION
## Notes To Consolidated Financial Statements—(Continued)

**Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets**

| | Duke Energy U.S. | | Westcoast | |
|---|---|---|---|---|
| | For the Years Ended December 31, | | | |
| | 2004 | 2003 | 2004 | 2003 |
| | (in millions) | | | |
| Projected benefit obligation | $2,693 | $2,763 | $479 | $432 |
| Accumulated benefit obligation | 2,607 | 2,646 | 434 | 393 |
| Fair value of plan assets | 2,477 | 2,477 | 361 | 323 |

**Assumptions Used for Pension Benefits Accounting**

| | Duke Energy U.S. | | | Westcoast | | |
|---|---|---|---|---|---|---|
| **Benefit Obligations** | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| | (percentages) | | | | | |
| Discount rate | 6.00 | 6.00 | 6.75 | 6.25 | 6.00 | 6.50 |
| Salary increase | 5.00 | 5.00 | 5.00 | 3.25 | 3.25 | 3.25 |

Net Periodic Benefit Cost

| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|---|
| Discount rate | 6.00 | 6.75 | 7.25 | 6.00 | 6.50 | 7.25 |
| Salary increase | 5.00 | 5.00 | 5.00 | 3.25 | 3.25 | 3.25 |
| Expected long-term rate of return on plan assets | 8.50 | 8.50 | 9.25 | 7.50 | 7.75 | 8.50 |

For the Duke Energy U.S. plan the discount rate used to determine the pension obligation is based on the current rates earned on long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

For Westcoast the discount rate used to determine the pension obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

**Plan Assets Duke Energy U.S.:**

| | Target | Percentage of Plan Assets at September 30 | |
|---|---|---|---|
| **Asset Category** | **Allocation** | **2004** | **2003** |
| US equity securities | 45% | 45% | 44% |
| Non-US equity securities | 20 | 21 | 20 |
| Debt securities | 32 | 31 | 35 |
| Real estate | 3 | 3 | 1 |
| Total | 100% | 100% | 100% |

Duke Energy U.S. assets for both the pension and other post retirement benefits are maintained by a Master Trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. U.S. equities are held for their high expected return. Non-U.S. equities, debt securities, and real estate are held for diversification. Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments. Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The long-term rate of return of 8.5% as of September 30, 2004 for the Duke Energy U.S. assets was developed using a weighted average calculation of expected returns based primarily on future expected returns across classes considering the use of active asset

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**Notes To Consolidated Financial Statements—(Continued)**

managers. The weighted average returns expected by asset classes were 4.2% for U.S. equities, 1.9% for Non-U.S. equities, 2.2% for fixed income securities, and 0.2% for real estate.

**Plan Assets Westcoast:**

| Asset Category | Target Allocation | Percentage of Plan Assets at September 30 2004 | 2003 |
|---|---|---|---|
| Canadian equity securities | 25% | 40% | 37% |
| US equity securities | 20 | 12 | 15 |
| EAFE equity securities[a] | 20 | 16 | 15 |
| Debt securities | 35 | 32 | 33 |
| Total | 100% | 100% | 100% |

(a) EAFE—Europe, Australasia, Far East

Westcoast assets for registered pension plans are maintained by a Master Trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. Canadian equities are held for their high expected return. Non-Canadian equities are held for their high expected return as well as diversification relative to Canadian equities and debt securities. Debt securities are also held for diversification. Under the Income Tax Act (Canada), pension funds are only permitted to invest 30% of the book value of assets in foreign investments.

The long-term rate of return of 7.5% as of September 30, 2004 for the Westcoast assets was developed using a weighted average calculation of expected returns based primarily on future expected returns across classes considering the use of active asset managers. The weighted average returns expected by asset classes were 2.0% for Canadian equities, 1.9% for U.S. equities, 1.9% for Europe, Australasia and Far East equities, and 1.7% for fixed income securities.

The following benefit payments, which reflect expected future service, as appropriate, as expected to be paid over the next five years and thereafter:

**Expected Benefit Payments**

| | U.S. Plan | Westcoast Plans |
|---|---|---|
| | (in millions) | |
| Years Ended December 31, | | |
| 2005 | $ 148 | $ 35 |
| 2006 | 159 | 36 |
| 2007 | 181 | 37 |
| 2008 | 197 | 38 |
| 2009 | 230 | 39 |
| 2010 – 2014 | 1,371 | 212 |

Duke Energy also sponsors employee savings plans that cover substantially all U.S. employees. Duke Energy contributes to the plan a matching contribution equal to 100% of before-tax employee contributions, of up to 6% of eligible pay per pay period. Duke Energy expensed employer matching contributions of $57 million in 2004, $63 million in 2003, and $71 million in 2002. Dividends on Duke Energy shares held by the savings plan are charged to retained earnings when declared and shares held in the plan are considered outstanding in the calculation of basic and diluted earnings per share.

Duke Energy also maintains a non-qualified, non-contributory defined benefit retirement plan which covers certain U.S. executives. Duke Energy recognized net periodic pension expense of $11 million in 2004, $11 million in 2003, and $10 million in 2002. There are no plan assets. The projected benefit obligation was $86 million as of September 30, 2004 and $101 million as of September 30, 2003.

Westcoast also provides non-registered defined benefit supplemental pensions to all employees who retire under a defined benefit registered pension plan and whose pension is limited by the maximum pension limits under the Income Tax Act (Canada). Westcoast

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**Notes To Consolidated Financial Statements—(Continued)**

recognized net periodic pension expense of $4 million in 2004, $4 million in 2003, and $3 million in 2002. There are no plan assets. The projected benefit obligation was $66 million as of September 30, 2004 and $60 million as of September 30, 2003.

**Duke Energy U.S. Other Post-Retirement Benefits.** Duke Energy and most of its subsidiaries provide some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

These benefit costs are accrued over an employee's active service period to the date of full benefits eligibility. The net unrecognized transition obligation, resulting from accrual accounting, is amortized over approximately 20 years.

**Westcoast Other Post-Retirement Benefits.** Westcoast provides health care and life insurance benefits for retired employees on a non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. Effective December 31, 2003, a new plan was implemented for all non bargaining employees and the majority of bargaining employees. The new plan will apply for employees retiring on and after January 1, 2006. The new plan is predominantly a defined contribution plan as compared to the existing defined benefit program.

Other post-retirement benefit costs are accrued over an employee's active service period to the date of full benefits eligibility. The net unrecognized transition obligation, resulting from accrual accounting, is amortized over the average remaining service period of the active employees covered by the plans. The average remaining service period of the active employees is 18 years.

**Components of Net Periodic Post-Retirement Benefit Costs**

| | Duke Energy U.S. | | | Westcoast | | |
|---|---|---|---|---|---|---|
| | For the Years Ended December 31, | | | | | |
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| | (in millions) | | | | | |
| Service cost benefit earned during the year | $ 5 | $ 5 | $ 5 | $ 3 | $ 2 | $ 2 |
| Interest cost on accumulated post-retirement benefit obligation | 47 | 51 | 50 | 5 | 4 | 2 |
| Expected return on plan assets | (19) | (21) | (24) | — | — | — |
| Amortization of prior service cost | 1 | 1 | 1 | (1) | — | — |
| Amortization of net transition liability | 16 | 18 | 18 | — | — | — |
| Curtailment loss | — | 21 | — | — | 1 | — |
| Amortization of loss | 8 | 5 | — | 1 | — | — |
| Net periodic post-retirement benefit costs | $ 58 | $ 80 | $ 50 | $ 8 | $ 7 | $ 4 |

During 2003, Duke Energy experienced workforce reductions and recognized other post-retirement employee benefits curtailments of $21 million.

**Reconciliation of Funded Status to Accrued Post-Retirement Benefit Costs**

| | Duke Energy U.S. | | Westcoast | |
|---|---|---|---|---|
| | For the Years Ended December 31, | | | |
| | 2004 | 2003 | 2004 | 2003 |
| | (in millions) | | | |
| **Change in Benefit Obligation** | | | | |
| Accumulated post-retirement benefit obligation at prior measurement date | $ 924 | $779 | $81 | $ 49 |
| Service cost | 5 | 5 | 3 | 2 |
| Interest cost | 47 | 51 | 5 | 4 |
| Plan participants' contributions | 16 | 12 | — | — |
| Actuarial (gain)/loss | (134) | 142 | (5) | 30 |
| Benefits paid | (76) | (66) | (3) | (2) |
| Divestiture | — | — | — | (2) |
| Plan curtailments | — | 1 | — | 1 |
| Plan amendments | — | — | — | (12) |
| Foreign currency impact | — | — | 5 | 11 |
| Accumulated post-retirement benefit obligation at measurement date | $ 782 | $924 | $86 | $ 81 |

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## Notes To Consolidated Financial Statements—(Continued)

| | Duke Energy U.S. | | Westcoast | |
|---|---|---|---|---|
| | For the Years Ended December 31, | | | |
| | 2004 | 2003 | 2004 | 2003 |
| | (in millions) | | | |
| **Change in Fair Value of Plan Assets** | | | | |
| Plan assets at prior measurement date | $ 242 | $ 227 | $ — | $ — |
| Actual return on plan assets | 20 | 32 | — | — |
| Benefits paid | (76) | (66) | (3) | (2) |
| Employer contributions | 41 | 37 | 3 | 2 |
| Plan participants' contributions | 16 | 12 | — | — |
| Plan assets at measurement date | $ 243 | $ 242 | $ — | $ — |
| Funded status | $(539) | $(682) | $(86) | $(81) |
| Employer contributions made after measurement date | 9 | 11 | 1 | 1 |
| Unrecognized net experience loss | 202 | 346 | 28 | 32 |
| Unrecognized prior service cost | 2 | 2 | (12) | (12) |
| Unrecognized transition obligation | 128 | 143 | — | — |
| Accrued post-retirement benefit costs | $(198) | $(180) | $(69) | $(60) |

For measurement purposes, plan assets were valued as of September 30 for both the Duke Energy U.S. and Westcoast plans.

In May 2004, the FASB staff issued FASB FSP 106-2. The Modernization Act introduced a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans. The FSP provides guidance on the accounting for the subsidy. Duke Energy adopted this FSP and retroactively applied this FSP as of the date of issuance for its U.S. plan. As a result of anticipated prescription drug subsidy, the accumulated post-retirement benefit obligation decreased by $96 million. The after-tax effect on net periodic post-retirement benefit cost was a decrease of $12 million for 2004. The actuarial gain included in the change in benefit obligation of $134 million in 2004 is primarily due to the recognition of anticipated employer savings as a result of Medicare Part D. FSP 106-2 provides guidance that the effect of the federal subsidy should be recognized as an actuarial gain.

### Assumptions Used for Post-Retirement Benefits Accounting

| | Duke Energy U.S. | | | Westcoast | | |
|---|---|---|---|---|---|---|
| **Determined Benefit Obligations** | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| | (percentages) | | | | | |
| Discount rate | 6.00 | 6.00 | 6.75 | 6.25 | 6.00 | 6.50 |
| Salary increase | 5.00 | 5.00 | 5.00 | 3.25 | 3.25 | 3.25 |

| | Duke Energy U.S. | | | Westcoast | | |
|---|---|---|---|---|---|---|
| **Determined Expense** | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| Discount rate | 6.00 | 6.75 | 7.25 | 6.00 | 6.50 | 7.25 |
| Salary increase | 5.00 | 5.00 | 5.00 | 3.25 | 3.25 | 3.25 |
| Expected long-term rate of return on plan assets | 8.50 | 8.50 | 9.25 | — | — | — |
| Assumed tax rate[a] | 39.11 | 39.11 | 39.60 | — | — | — |

a Applicable to the health care portion of funded post-retirement benefits

For the Duke Energy U.S. plan the discount rate used to determine the pension obligation is based on current rates earned on long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

For Westcoast the discount rate used to determine the pension obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

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## Notes To Consolidated Financial Statements—(Continued)

**Plan Assets Duke Energy U.S.:**

| Asset Category | Target Allocation | Percentage of Plan Assets at September 30 2004 | 2003 |
|---|---|---|---|
| US equity securities | 45% | 45% | 44% |
| Non-US equity securities | 20 | 21 | 20 |
| Debt securities | 32 | 31 | 35 |
| Real estate | 3 | 3 | 1 |
| Total | 100% | 100% | 100% |

Duke Energy U.S. assets for both the pension and other post retirement benefits are maintained by a Master Trust. The investment objective of the trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. US equities are held for their high expected return. Non-US equities, debt securities, and real estate are held for diversification. Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments. Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

Duke Energy also invests other post-retirement assets in the Duke Energy Corporate Employee Benefits Trust (VEBA I) and the Duke Energy Corporation Post-Retirement Medical Benefits Trust (VEBA II). The investment objective of the VEBA's is to achieve sufficient returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants. The VEBA trusts are passively managed. VEBA I has a target allocation of 30% U.S. equities, 45% fixed income securities and 25% cash. VEBA II has a target allocation of 50% U.S. equities and 50% fixed income securities.

The long-term rate of return of 8.5% as of September 30, 2004 for the Duke Energy U.S. assets was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers. The weighted average returns expected by asset classes were 4.2% for U.S. equities, 1.9% for Non U.S. equities, 2.2% for fixed income securities, and 0.2% for real estate.

**Assumed Health Care Cost Trend Rates**

| | Duke Energy U.S. | | | | | |
|---|---|---|---|---|---|---|
| | Not Medicare Eligible | | Medicare Eligible | | Westcoast | |
| | 2004 | 2003 | 2004 | 2003 | 2004 | 2003 |
| Health care cost trend rate assumed for next year | 9.50% | 10.50% | 12.5% | 13.50% | 9.00% | 10.00% |
| Rate to which the cost trend is assumed to decline (the ultimate trend rate) | 6.00% | 6.00% | 6.00% | 6.00% | 5.00% | 5.00% |
| Year that the rate reaches the ultimate trend rate | 2009 | 2009 | 2012 | 2012 | 2008 | 2008 |

**Sensitivity to Changes in Assumed Health Care Cost Trend Rates Duke Energy U.S. Plan** (millions)

| | 1-Percentage-Point Increase | 1-Percentage-Point Decrease |
|---|---|---|
| Effect on total service and interest costs | $ 3 | $ (3) |
| Effect on post-retirement benefit obligation | 50 | (40) |

**Sensitivity to Changes in Assumed Health Care Cost Trend Rates Westcoast Plans** (millions)

| | 1-Percentage-Point Increase | 1-Percentage-Point Decrease |
|---|---|---|
| Effect on total service and interest costs | $ 1 | $ — |
| Effect on post-retirement benefit obligation | 11 | (10) |

DUKE ENERGY CORPORATION

**Notes To Consolidated Financial Statements—(Continued)**

Duke Energy and Westcoast expect to make the future benefit payments, which reflect expected future service, as appropriate. Duke Energy expects to receive future subsidies under Medicare Part D. The following benefit payments and subsidies are expected to be paid (or received) over each of the next five years and thereafter.

**Expected Benefit Payments and Subsidies (in millions)**

| | U.S. Plan Payments | U.S. Plan Expected Subsidies | Westcoast Plans |
|---|---|---|---|
| | | (in millions) | |
| 2005 | $ 58 | $ — | $ 4 |
| 2006 | 60 | 7 | 4 |
| 2007 | 62 | 8 | 5 |
| 2008 | 64 | 8 | 5 |
| 2009 | 66 | 9 | 5 |
| 2010 – 2014 | 345 | 47 | 30 |

## 22. Quarterly Financial Data (Unaudited)

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Total |
|---|---|---|---|---|---|
| | (In millions, except per share data) | | | | |
| **2004** | | | | | |
| Operating revenues | $5,635 | $5,318 | $5,504 | $ 6,046 | $22,503 |
| Operating income | 432 | 830 | 878 | 874 | 3,014 |
| Net income | 311 | 432 | 389 | 358 | 1,490 |
| Earnings available for common stockholders | 309 | 429 | 387 | 356 | 1,481 |
| Earnings per share | | | | | |
| Basic | $ 0.34 | $ 0.46 | $ 0.41 | $ 0.38 | $ 1.59 |
| Diluted[a] | $ 0.33 | $ 0.45 | $ 0.40 | $ 0.36 | $ 1.54 |
| **2003** | | | | | |
| Operating revenues | $6,148 | $5,136 | $5,547 | $ 5,249 | $22,080 |
| Operating income (loss) | 889 | 678 | 245 | (2,665) | (853) |
| Income (loss) before cumulative effect of change in accounting principle | 387 | 424 | 49 | (2,021) | (1,161) |
| Net income (loss) | 225 | 424 | 49 | (2,021) | (1,323) |
| Earnings (loss) available for common stockholders | 222 | 417 | 46 | (2,023) | (1,338) |
| Earnings (loss) per share before cumulative effect of change in accounting principle | | | | | |
| Basic | $ 0.43 | $ 0.46 | $ 0.05 | $ (2.23) | $ (1.30) |
| Diluted[b] | $ 0.43 | $ 0.45 | $ 0.05 | $ (2.23) | $ (1.30) |
| Earnings (loss) per share | | | | | |
| Basic | $ 0.25 | $ 0.46 | $ 0.05 | $ (2.23) | $ (1.48) |
| Diluted[c] | $ 0.25 | $ 0.45 | $ 0.05 | $ (2.23) | $ (1.48) |

(a) Diluted EPS for the first, second and third quarters was restated due to the retroactive application of EITF 04-08. Previously reported diluted EPS was $0.34, $0.46 and $0.41, respectively.
(b) Diluted EPS (before cumulative change in accounting principle) for the second quarter was restated due to the retroactive application of EITF 04-08. Previously reported diluted EPS was $0.46.
(c) Diluted EPS for the second quarter was restated due to the retroactive application of EITF 04-08. Previously reported diluted EPS was $0.46.

The amounts in the above tables have been adjusted from previously reported amounts due to operations that were classified as discontinued operations as of the fourth quarter of 2004 (see Note 13). Also, diluted EPS (before cumulative effect of change in accounting principle) and diluted EPS have been restated due to the retroactive application of EITF 04-08 (See Note 1).

During the first quarter of 2004, Duke Energy recorded the following unusual or infrequently occurring items: a $256 million pre-tax gain on sale of International Energy's Asia-Pacific Business (see Note 13); and an approximate $360 million pre-tax charge in 2004 associated with the sale of DENA's Southeast Plants (see Note 2).

DUKE ENERGY CORPORATION
**Notes To Consolidated Financial Statements—(Continued)**

During the second quarter of 2004, Duke Energy recorded the following unusual or infrequently occurring items: a $130 million (net of minority interest of $5 million) pre-tax gain related to the settlement of the Enron bankruptcy proceedings; a $39 million net increase in the pre-tax gains ($30 million increase to the after tax gains) originally recorded on the sales of International Energy's Asia-Pacific Business (see Note 13 ) and its European Business; a $52 million release of various income tax reserves (see Note 6); and a $105 million pre-tax charge related to the California and Western U.S. energy markets settlement (see Note 17).

During the third quarter of 2004, Duke Energy recorded the following unusual or infrequently occurring items: a $48 million tax benefit related to the realignment of certain subsidiaries of Duke Energy and the pass-through structure of these for U.S. income tax purposes (see Note 6); and impairments of $45 million (net of minority interest of $26 million) related to asset impairments, losses on asset sales and write-down of equity investments at Field Services (see note 12).

During the fourth quarter of 2004, Duke Energy recorded the following unusual or infrequently occurring items: a $180 million of pre-tax gains associated with the sales of two DENA partially completed facilities, Luna and Moapa (See Note 2); a $64 million pre-tax correction of accounting errors related to the elimination of intercompany reserves at Bison (see Note 1); $45 million in taxes recorded in 2004 on the repatriation of foreign earnings that is expected to occur in 2005 associated with the American Jobs Creation Act of 2004; a $51 million pre-tax charge related to the sale of DETM contracts that were held in a net liability position; $20 million in contract termination charges related to the DENA partially completed plant at Grays Harbor; and approximately $42 million of impairment charges related to two Crescent residential developments in Payson, Arizona and one in Austin, Texas (See Note 12); and $8 million in bad debt charges recorded by Crescent related to notes receivable due from Rim Golf Investor LLC and Chaparral Pines Investor LLC. The bad debt charges are recorded in Operation, Maintenance and Other on the Consolidated Statement of Operations (See Note 12).

During the second quarter of 2003, Duke Energy recorded a $178 million pre-tax gain from the sale of DENA's 50% interest in Ref-Fuel. (See Note 2).

During the third quarter of 2003, Duke Energy recorded the following unusual or infrequently occurring items: goodwill impairment related to DENA's trading and marketing business of $254 million (see Note 10), severance charges of $105 million for work force reductions; a regulatory action by the PSCSC which resulted in decreased earnings of $46 million at Franchised Electric (see Note 4); a $52 million tax benefit related to International Energy's goodwill impairment recognized in 2002 for the gas trading business in Europe; and a settlement with the Commodity Futures Trading Commission of $17 million, net of minority interest expense, by DENA.

During the fourth quarter of 2003, Duke Energy recorded the following unusual or infrequently occurring items: impairments on DENA's Southeast Plants and its deferred Western plants and charges for the re-designation of certain hedges at DENA from accrual to mark-to-market that were related to its impaired assets of $2,903 million (see Note 12); charges and impairments of $292 million to complete International Energy's exit from the European market and the divestiture of its Asia-Pacific Business; a $51 million write-off of an abandoned corporate risk management information system; severance charges of $48 million for workforce reductions; additional employee benefit expense of approximately $28 million; and right of way clearing costs of approximately $40 million at Franchised Electric.

## 23. Subsequent Events

In February 2005, DEFS sold its wholly-owned subsidiary TEPPCO for approximately $1.1 billion and Duke Energy sold its limited partner interest in TEPPCO Partners, L.P. for approximately $100 million, in each case to EPCO, an unrelated third party.

Additionally, in February 2005, Duke Energy executed an agreement with ConocoPhillips whereby Duke Energy has agreed to transfer a 19.7% interest in DEFS to ConocoPhillips for direct and indirect monetary and non-monetary consideration of approximately $1.1 billion. The consideration is expected to consist of the current Canadian operations of DEFS, the transfer of certain Canadian assets from ConocoPhillips to Duke Energy and the transfer of certain U.S. Midstream assets, or cash, from ConocoPhillips to DEFS, and the payment of cash from ConocoPhillips to Duke Energy of at least $500 million. Upon completion of this transaction, DEFS will be owned 50% by Duke Energy and 50% by ConocoPhillips. As a result, Duke Energy expects to account for its investment in DEFS using the equity method subsequent to closing of the transaction. This transaction, which is subject to customary U.S. and Canadian regulatory approvals, is expected to close in the latter half of 2005.

As a result, Duke Energy expects to deconsolidate its investment in DEFS, subsequent to the closing of the transfer of its 19.7% interest to ConocoPhillips. During the first quarter of 2005 Duke Energy has discontinued hedge accounting for certain 2005 and 2006 contracts held by Duke Energy related to Field Services' commodity risk, which were previously accounted for as cash flow hedges. As a result of discontinuation of hedge accounting treatment, approximately $140 million of pretax deferred losses in AOCI related to these contracts have been reclassified into earnings by Duke Energy in the first quarter of 2005. On a prospective basis, these contracts will be accounted for under the MTM Model.

DUKE ENERGY CORPORATION

**Notes To Consolidated Financial Statements—(Continued)**

Additionally, in connection with the transactions discussed above, Duke Energy has announced plans to periodically repurchase up to an aggregate $2.5 billion of common stock over the next three years.

On March 1, 2005, notices were sent to the bondholders of the $100 million PanEnergy 8.625% bonds due in 2025. The bondholders were notified that these securities would be called on April 15, 2005, the earliest date at which these bonds can be redeemed.

On March 9, 2005, Duke Power filed with the NCUC a proposed fuel rate increase, for rates effective July 1, 2005 for a twelve-month period. To reduce the impact of the increased cost of fuel, Duke Power is seeking approval in the fuel case proceeding to credit the deferred fuel account by approximately $100 million for previously recorded excess deferred tax liabilities that are recorded as regulatory liabilities. The filing has not yet been approved. No similar action has yet been proposed to the PSCSC.

DUKE ENERGY CORPORATION

## SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

| | Balance at Beginning of Period | Additions: Charged to Expense | Additions: Charged to Other Accounts | Deductions[a] | Balance at End of Period |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| December 31, 2004: | | | | | |
| Injuries and damages | $1,319 | $ 8 | $ 2 | $ 60 | $1,269 |
| Allowance for doubtful accounts | 280 | 87 | 6 | 220 | 153 |
| Other[b] | 415 | 165 | 57 | 257 | 380 |
| | $2,014 | $260 | $ 65 | $537 | $1,802 |
| December 31, 2003: | | | | | |
| Injuries and damages | $ 367 | $ 1 | $1,024[d] | $ 73 | $1,319 |
| Allowance for doubtful accounts | 349 | 65 | 16 | 150 | 280 |
| Other[b] | 513 | 183 | 18 | 299 | 415 |
| | $1,229 | $249 | $1,058 | $522 | $2,014 |
| December 31, 2002: | | | | | |
| Injuries and damages | $ 459 | $ 14 | $ 5 | $111 | $ 367 |
| Allowance for doubtful accounts | 265 | 161 | 5 | 82 | 349 |
| Other[b] | 406 | 222 | 114[c] | 229 | 513 |
| | $1,130 | $397 | $ 124 | $422 | $1,229 |

(a) Principally cash payments and reserve reversals.
(b) Principally property insurance reserves and litigation and other reserves, included in Other Current Liabilities, or Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.
(c) Includes the reclassification of $50 million of a $58 million suspense account to a nuclear insurance operation account in accordance with a settlement agreement between Duke Power, the NCUC and the PSCSC.
(d) Primarily represents changes in estimates for certain contingent liabilities which are covered by insurance and also recognized as an insurance receivable which is included in Other noncurrent assets on the Consolidated Balance Sheets.

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

None.

## Item 9A. Controls and Procedures.

### Disclosure Controls and Procedures

Duke Energy's management, including the Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Duke Energy's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) (Disclosure Controls Evaluation) and concluded that, as of the end of the period covered by this report, the disclosure controls and procedures are effective in ensuring that all material information required to be filed in this annual report has been made known to them in a timely fashion. The required information was effectively recorded, processed, summarized and reported within the time period necessary to prepare this annual report. Duke Energy's disclosure controls and procedures are effective in ensuring that information required to be disclosed in Duke Energy's reports under the Exchange Act are accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

### Management's Annual Report On Internal Control Over Financial Reporting

See Item 8. Financial Statements and Supplementary Data

### Attestation Report of the Independent Registered Public Accounting Firm

See Item 8. *Financial Statements and Supplementary Data*

### Changes in Internal Control over Financial Reporting

Because of Duke Energy's ongoing evaluation of internal controls over financial reporting, management continues to implement procedures and controls to enhance the reliability of Duke Energy's internal control procedures including planned improvements in our financial closing and consolidation processes. However, there have been no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, Duke Energy's internal control over financial reporting.

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

Reference to "Executive Officers of Duke Energy" is included in "Item 1. Business" of this report. See "The Board of Directors," "Information on the Board of Directors" and "Other Information" in the Proxy Statement relating to Duke Energy's 2005 annual meeting of shareholders, incorporated herein by reference.

Duke Energy has adopted a code of ethics entitled "Code of Business Ethics" that applies to all officers (including the principal executive officers, principal financial officer and controller) and all other employees of Duke Energy and Duke Energy's subsidiaries. The "Code of Business Ethics" is posted on Duke Energy's Internet Web site: *http://www.duke-energy.com/investors/governance/ethics/* and is available in print to any shareholder who requests it. In satisfaction of the disclosure requirements of Item 5.05 of Form 8-K, Duke Energy will disclose on this website any amendments to, or waivers to, provisions of the "Code of Business Ethics" that apply to its principal executive officers, principal financial officer and controller and that relate to any element of this code enumerated in Item 406(b) of Regulation S-K.

Directors are held to the same high standards of business conduct as employees. Duke Energy's Board of Directors has approved and Duke Energy has adopted a "Code of Business Conduct and Ethics for Members of the Board of Directors of Duke Energy Corporation," applicable to all members of Duke Energy's Board of Directors, that set forth standards of conduct for directors. This code includes those standards from the employees' code which directly apply to the roles and responsibilities of a director. The director's code is posted on Duke Energy's Internet Web site: *http://www.duke-energy.com/governance/board/conduct/* and is available in print to any shareholder who requests it.

Duke Energy also has adopted its "Principles of Corporate Governance," which addresses, among other things, director and board committee responsibilities. These guidelines are posted on Duke Energy's Internet Web site: *http://www.duke-energy.com/investors/governance/principles/* and are available in print to any shareholder who requests it.

On June 4, 2004, Paul M. Anderson, Duke Energy's Chief Executive Officer, filed with the New York Stock Exchange (NYSE) a certification, as required by the NYSE's Corporate Governance Standards, that he is not aware of any violation by Duke Energy of those standards. Mr. Anderson and David L. Hauser, Duke Energy's Chief Financial Officer, signed certifications as required by Section 302 of the Sarbanes-Oxley Act of 2002 with respect to Duke Energy's Consolidated Financial Statements for the year ended December 31, 2003, and those certifications were filed as exhibits to Duke Energy's Form 10-K for the year ended December 31, 2003.

### Item 11. Executive Compensation.

See "Executive Compensation" and "Information on the Board of Directors—Compensation of Directors" in the Proxy Statement relating to Duke Energy's 2005 annual meeting of shareholders, incorporated herein by reference.

### Item 12. Security Ownership of Certain Beneficial Owners and Management.

See "Beneficial Ownership" in the Proxy Statement relating to Duke Energy's 2005 annual meeting of shareholders, incorporated herein by reference.

## EQUITY COMPENSATION PLAN DISCLOSURE

This table shows information about securities to be issued upon exercise of outstanding options, warrants and rights under Duke Energy's equity compensation plans, along with the weighted-average exercise price of the outstanding options, warrants and rights and the number of securities remaining available for future issuance under the plans.

| Plan Category | Number of securities to be issued upon exercise of outstanding options, warrants and rights[1] (a) | Weighted-average exercise price of outstanding options, warrants and rights[1] (b) | Number of securities remaining available under equity compensation plans (excluding securities reflected in column (a)) (c) |
|---|---|---|---|
| Equity compensation plans approved by security holders | 27,029,876[2] | $29.20 | 25,948,990[3] |
| Equity compensation plans not approved by security holders | None | None | None |
| Total | 27,029,876 | $29.20 | 25,948,990 |

1 Duke Energy has not granted any warrants or rights under any equity compensation plans. Amounts do not include 1,526,325 outstanding options with a weighted average exercise price of $23.84 assumed in connection with various mergers and acquisitions.
2 Does not include 3,743,386 shares of Duke Energy Common Stock to be issued upon vesting, if shares vest, of phantom stock and performance share awards outstanding as of December 31, 2004.
3 Includes 6,910,639 shares remaining available for issuance for awards of restricted stock, performance shares or phantom stock under the Duke Energy Corporation 1998 Long-Term Incentive Plan.

### Item 13. Certain Relationships and Related Transactions

*None.*

### Item 14. Principal Accounting Fees and Services.

See "Other Information—Fees Paid to Independent Auditors" in the Proxy Statement relating to Duke Energy's 2005 annual meeting of shareholders, incorporated herein by reference.

## Item 15. Exhibits and Financial Statement Schedule.

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedule included in Part II of this annual report are as follows:

Consolidated Financial Statements

Consolidated Statements of Operations for the Years Ended December 31, 2004, 2003 and 2002

Consolidated Statements of Cash Flows for the Years Ended December 31, 2004, 2003 and 2002

Consolidated Balance Sheets as of December 31, 2004 and 2003

Consolidated Statements of Common Stockholders' Equity and Comprehensive Income (Loss) for the Years ended December 31, 2004, 2003 and 2002

Notes to the Consolidated Financial Statements

Quarterly Financial Data, as revised (unaudited, included in Note 22 to the Consolidated Financial Statements)

Consolidated Financial Statement Schedule II—Valuation and Qualifying Accounts and Reserves for the years Ended December 31, 2004, 2003 and 2002

Report of Independent Registered Public Accounting Firm

All other schedules are omitted because they are not required, or because the required information is included in the Consolidated Financial Statements or Notes.

(c) Exhibits—See Exhibit Index immediately following the signature page.

## SIGNATURES

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

Date: March 15, 2005

DUKE ENERGY CORPORATION
(Registrant)

By: PAUL M. ANDERSON

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

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

(i) Principal executive officer:
Paul M. Anderson
Chairman of the Board and Chief Executive Officer

(ii) Principal financial officer:
David L. Hauser
Group Vice President and Chief Financial Officer

(iii) Principal accounting officer:
Keith G. Butler
Vice President and Controller

(iv) A majority of the Directors:
Roger Agnelli
Paul M. Anderson
G. Alex Bernhardt, Sr.
Robert J. Brown
William T. Esrey
Ann Maynard Gray
Dennis Hendrix
George Dean Johnson, Jr.
A. Max Lennon
Leo E. Linbeck, Jr.
James G. Martin
Michael E.J. Phelps
James T. Rhodes

Date: March 15, 2005

David L. Hauser, by signing his name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

By: /s/ DAVID L. HAUSER

Attorney-In-Fact

## EXHIBIT INDEX

Exhibits filed herewith are designated by an asterisk (*). All exhibits not so designated are incorporated by reference to a prior filing, as indicated. Items constituting management contracts or compensatory plans or arrangements are designated by a double asterisk (**).

| Exhibit Number | |
|---|---|
| 2-1 | Amended and Restated Combination Agreement dated as of September 20, 2001, among Duke Energy Corporation, 3058368 Nova Scotia Company, 3946509 Canada Inc. and Westcoast Energy Inc. (filed with Form 10-Q of the registrant for the quarter ended September 30, 2001, File No. 1-4928, as Exhibit 10.7). |
| 3-1 | Restated Articles of Incorporation of registrant, dated June 18, 1997 (filed with Form S-8, No. 333-29563, effective June 19, 1997, as Exhibit 4(G)). |
| 3-2 | Articles of Amendment to Restated Articles of Incorporation of registrant, dated February 9, 1999 (filed with Form 8-K of the registrant on February 11, 1999, File No. 1-4928, as Exhibit A to Exhibit 4.1). |
| 3-3 | Articles of Amendment to Restated Articles of Incorporation of registrant, dated April 28, 1999 (filed with Form S-3 of the registrant, file number 333-81573, filed June 25, 1999 as Exhibit 4(B)). |
| 3-4 | Articles of Amendment to Restated Articles of Incorporation of registrant, dated May 2, 2001 (filed with Post-Effective Amendment No. 2 to Form S-3 of the registrant, file number 333-81573, filed December 12, 2001, as Exhibit 4(B)-1). |
| 3-5 | Articles of Amendment to Restated Articles of Incorporation of registrant, dated May 1, 2002 (filed with Form 10-Q of the registrant for the quarter ended March 31, 2002, File No. 1-4928, as Exhibit 3). |
| 3-6 | By-Laws of registrant, as amended (filed with Form 10-K for the year ended December 31, 2002, File No. 1-4928, as Exhibit 3-4). |
| 4 | Rights Agreement, dated as of December 17, 1998, between the registrant and The Bank of New York, as Rights Agent (filed with Form 8-K dated February 11, 1999, as Exhibit 4.1). |
| 10-1** | Directors' Charitable Giving Program (filed with Form 10-K of the registrant for the year ended December 31, 1992, File No. 1-4928, as Exhibit 10-P). |
| 10-1.1** | Amendment to Directors' Charitable Giving Program dated June 18, 1997 (filed with Form 10-K of the registrant for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-1.1). |
| 10-1.2** | Amendment to Directors' Charitable Giving Program dated July 28, 1997 (filed with Form 10-K of the registrant for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-1.2). |
| 10-1.3** | Amendment to Directors' Charitable Giving Program dated February 18, 1998 (filed with Form 10-K of the registrant for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-1.3). |
| 10-2 | $600,000,000 364-Day Credit Agreement dated as of June 30, 2004, among Duke Capital LLC, the Banks listed therein and JPMorgan Chase Bank, as Administrative Agent (filed with Form 10-Q of the registrant for the quarter ended June 30, 2004, File No. 1-4928, as Exhibit 10-1). |
| 10-2.1 | $600,000,000 Three-Year Credit Agreement dated as of June 30, 2004, among Duke Capital LLC, the Banks listed therein and JPMorgan Chase Bank, as Administrative Agent (filed with Form 10-Q of the registrant for the quarter ended June 30, 2004, File No. 1-4928, as Exhibit 10-2). |
| 10-2.2 | $500,000,000 Three-Year Credit Agreement dated as of June 30, 2004, among Duke Energy Corporation, the Banks listed therein and Citicorp USA Inc., as Administrative Agent (filed with Form 10-Q of the registrant for the quarter ended June 30, 2004, File No. 1-4928, as Exhibit 10-3). |
| 10-3 | Formation Agreement between PanEnergy Trading and Market Services, Inc. and Mobil Natural Gas, Inc. dated May 29, 1996 (filed with Form 10-Q of PanEnergy Corp for the quarter ended June 30, 1996, File No. 1-8157, as Exhibit 2). |

| Exhibit Number | |
|---|---|
| 10-4** | Duke Energy Corporation 1998 Long-Term Incentive Plan, as amended (filed as Exhibit 1 to Schedule 14A of the registrant, March 28, 2003, File No. 1-4928). |
| 10-4.1** | Form of Performance Award Agreement dated February 28, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and each of Fred J. Fowler, David L. Hauser, Jimmy W. Mogg and Ruth G. Shaw (filed as Exhibit 10.1 of Current Report on Form 8-K of the registrant, filed on February 28, 2005). |
| 10-4.2** | Form of Phantom Stock Award Agreement dated February 28, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and each of Fred J. Fowler, David L. Hauser, Jimmy W. Mogg and Ruth G. Shaw (filed as Exhibit 10.2 of Current Report on Form 8-K of the registrant, filed on February 28, 2005). |
| 10-5** | Duke Energy Corporation Executive Short-Term Incentive Plan (filed as Exhibit 2 to Schedule 14A of registrant, March 28, 2003, File No. 1-4928). |
| 10-6** | Duke Energy Corporation Executive Savings Plan, as amended and restated (filed with Form 10-K of the registrant for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-6). |
| *10-6.1** | Amendment No. 1 to the Duke Energy Corporation Executive Savings Plan, dated October 27, 2004, effective December 31, 2004. |
| 10-7** | Duke Energy Corporation Executive Cash Balance Plan (filed with Form 10-K Report of TEPPCO Partners, LP, File No. 1-10403, for the year ended December 31, 1999, as Exhibit 10.8). |
| *10-7.1** | Amendment No. 1 to the Duke Energy Corporation Executive Cash Balance Plan, dated August 26, 1999. |
| *10-7.2** | Amendment No. 2 to the Duke Energy Corporation Executive Cash Balance Plan, dated March 6, 2000. |
| *10-7.3** | Amendment No. 3 to the Duke Energy Corporation Executive Cash Balance Plan, dated December 21, 2000. |
| *10-7.4** | Amendment No. 4 to the Duke Energy Corporation Executive Cash Balance Plan, dated October 27, 2004, effective December 31, 2004. |
| 10-8** | Duke Energy Corporation Retirement Benefit Equalization Plan (filed with Form 10-K Report of TEPPCO Partners, LP, File No. 1-10403, for the year ended December 31, 1999, as Exhibit 10.9). |
| 10-9** | Form of Key Employee Severance Agreement and Release between Duke Energy Corporation and certain key executives (filed with Form 10-K of the registrant for the year ended December 31, 1999, as Exhibit 10-BB). |
| 10-10** | Form of Change in Control Agreement between Duke Energy Corporation and certain key executives (filed with Form 10-K of the registrant for the year ended December 31, 1999, as Exhibit 10-CC). |
| 10-14 | Parent Company Agreement dated as of March 31, 2000 among Phillips Petroleum Company, Duke Energy Corporation, Duke Energy Field Services, LLC and Duke Energy Field Services Corporation (filed as Exhibit 10.10 to Registration Statement on Form S-1/A (Registration No. 333-32502) of Duke Energy Field Services LLC, filed on May 4, 2000). |
| 10-14.1 | First Amendment to the Parent Company Agreement dated as of May 25, 2000 among Phillips Petroleum Company, Duke Energy Corporation, Duke Energy Field Services, LLC and Duke Energy Field Services Corporation (filed as Exhibit 10.8 (b) to Form 10 of Duke Energy Field Services LLC, File No. 000-31095, filed July 20, 2000). |
| 10-14.2 | Second Amendment to Parent Company Agreement among Phillips Petroleum Company, Duke Energy Corporation, Duke Energy Field Services, LLC, and Duke Energy Field Services Corporation dated as of August 4, 2000 (filed as Exhibit 10.1 of Current Report on Form 8-K of Duke Energy Field Services, LLC filed on August 16, 2000). |

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| 10-14.3 | Third Amendment to Parent Company Agreement among Duke Energy Field Services Corporation, Duke Energy Field Services, LLC, ConocoPhillips Company and Duke Energy Corporation dated as of July 29, 2004 (field as Exhibit 10.1 of Quarterly Report on Form 10-Q of Duke Energy Field Services, LLC filed on November 10, 2004). |
| 10-15 | Amended and Restated Limited Liability Company Agreement of Duke Energy Field Services, LLC by and between Phillips Gas Company and Duke Energy Field Services Corporation, dated as of March 31, 2000 (filed as Exhibit 3.1 to Form 10 of Duke Energy Field Services LLC, File No. 000-31095, filed July 20, 2000). |
| 10-15.1 | First Amendment to Amended and Restated Limited Liability Company Agreement of Duke Energy Field Services, LLC dated as of August 4, 2000 (filed as Exhibit 3.1 of Current Report on Form 8-K of Duke Energy Field Services, LLC filed on August 16, 2000). |
| 10-15.2 | Second Amendment to Amended and Restated Limited Liability Company Agreement of Duke Energy Field Services, LLC dated as of July 29, 2004 (filed as Exhibit 3.1 of Quarterly Report on Form 10-Q of Duke Energy Field Services, LLC filed on November 10, 2004). |
| 10-17 | Limited Liability Company Agreement of Gulfstream Management & Operating Services, LLC dated as of February 1, 2001 between Duke Energy Gas Transmission Corporation and Williams Gas Pipeline Company (filed with Form 10-K of the registrant for the year ended December 31, 2002, File No.1-4928, as Exhibit 10-18). |
| 10-18** | Employment Agreement dated November 2003 between Paul M. Anderson and Duke Energy Corporation (filed with Form 10-K of the registrant for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-18). |
| 10-18.1** | First Amendment to Employment Agreement dated March 9, 2004 between Paul M. Anderson and Duke Energy Corporation (filed with Form 10-K of the registrant for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-18.1). |
| *10-18.2** | Performance Award Agreement dated November 17, 2003, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan, by and between Duke Energy Corporation and Paul M. Anderson. |
| *10-18.3** | Phantom Stock Agreement dated November 17, 2003, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan, by and between Duke Energy Corporation and Paul M. Anderson. |
| *10-18.4** | Non-Qualified Option Agreement dated as of November 17, 2003 pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan, by and between Duke Energy Corporation and Paul M. Anderson. |
| 10-19** | Supplemental Compensation Agreement dated June 17, 1997 between Duke Power Company and Dr. Ruth G. Shaw (filed with Form 10-K of the registrant for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-19). |
| 10-20** | Separation Agreement and General Release dated January 30, 2004 between Duke Energy Corporation and Robert Brace (filed with Form 10-K of the registrant for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-20). |
| 10-21** | Letter agreement dated January 28, 2004 between Duke Energy Corporation and Richard W. Blackburn (filed with Form 10-K of the registrant for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-21). |
| 10-22** | Amendment and Supplement to Key Employee Severance Agreement and General Release dated as of February 2, 2004 between Duke Energy Corporation and Richard B. Priory (filed with Form 10-K of the registrant for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-22). |
| *10-23** | Agreement between Duke Energy Corporation and Jimmy W. Mogg relating to certain retirement benefits, consisting of letter agreements dated May 25, 1995, August 4, 2001 and March 29, 2004. |
| 10-24** | First Amendment to Key Employee Severance Agreement and General Release between Duke Energy Corporation and Richard J. Osborne, dated August 21, 2004 (filed with Form 10-Q of the registrant for the quarter ended October 31, 2004, File No. 1-4928, as Exhibit 10-2). |

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| 10-24.1** | First Amendment to Change in Control Agreement and General Release between Duke Energy Corporation and Richard J. Osborne, dated August 18, 2004 (filed with Form 10-Q of the registrant for the quarter ended October 31, 2004, File No. 1-4928, as Exhibit 10-3). |
| *10-25 | Purchase and Sale Agreement dated as of February 24, 2005, by and between Enterprise GP Holdings LP and Duke Energy Field Services, LLC. |
| *10-26 | Term Sheet Regarding the Restructuring of Duke Energy Field Services LLC dated as of February 23, 2005, between Duke Energy Corporation and ConocoPhillips. |
| *10-27** | Summary of Directors' Fees as of May 1, 2004. |
| 10-28** | Certification of Chairman and Chief Executive Officer 2004 Performance Goals (filed in Form 8-K of the registrant, February 28, 2005, File No. 1-4928, as item 1 of Item 1.01). |
| 10-29** | Approval of Payment of 2004 Executive Officer Short-Term Incentives (filed in Form 8-K of the registrant, February 28, 2005, File No. 1-4928, as item 2 of Item 1.01). |
| 10-30** | Establishment of Chairman and Chief Executive Officer 2005 Performance Goals (filed in Form 8-K of the registrant, February 28, 2005, File No. 1-4928, as item 3 of Item 1.01). |
| 10-31** | 2005 Executive Officer Base Salaries, Short-Term Incentive Opportunities and Long-Term Incentive Opportunities (filed in Form 8-K of the registrant, February 28, 2005, File No. 1-4928, as item 4 of Item 1.01). |
| *12 | Computation of Ratio of Earnings to Fixed Charges. |
| *21 | List of Subsidiaries. |
| *23-1 | Consent of Independent Registered Public Accounting Firm. |
| *24-1 | Power of attorney authorizing David L. Hauser and others to sign the annual report on behalf of the registrant and certain of its directors and officers. |
| *24-2 | Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney. |
| *31.1 | Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| *31.2 | Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| *32.1 | Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| *32.2 | Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

The total amount of securities of the registrant or its subsidiaries authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to it.