DUKE ENERGY CORP
Form 10-K/A
August 09, 2004
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

Amendment No. 1

FOR ANNUAL AND TRANSITION REPORTS

PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

(Mark One)

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

For the fiscal year ended December 31, 2003 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 **(State or other jurisdiction of incorporation or organization)**	**56-0205520** **(I.R.S. Employer Identification No.)**
526 South Church Street, Charlotte, North Carolina	**28202-1803**

(Address of principal executive offices) **(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.
7.20% Quarterly Income Preferred Securities issued by Duke Energy Capital Trust I and guaranteed by Duke Energy Corporation	New York Stock Exchange, Inc.
7.20% Trust Preferred Securities issued by Duke Energy Capital Trust II and guaranteed by Duke Energy Corporation	New York Stock Exchange, Inc.
Preference Stock Purchase Rights	New York Stock Exchange, Inc.
Series C 6.60% Senior Notes Due 2038	New York Stock Exchange, Inc.
Corporate Units	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 x No ¨

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

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 x No ¨

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant at June 30, 2003	$ 18,018,000,000
Number of shares of Common Stock, without par value, outstanding at March 2, 2004	912,888,377

Documents incorporated by reference:

The registrant is incorporating herein by reference certain sections of the proxy statement relating to the 2004 annual meeting of shareholders to provide information required by Part II, portions of Item 5, and Part III, Items 10, 11, 12,13 and 14 of this annual report.

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Explanatory Note

This Amendment No. 1 to the Annual Report on Form 10-K of Duke Energy Corporation (Duke Energy) for the fiscal year ended December 31, 2003 is being filed for the purpose of amending and revising Items 1, 2, 3, 6, 7, 8, 9A and 15. This Form 10-K/A is being filed in order to (1) present Duke Energy s real estate operations, Crescent Resources, LLC (Crescent), as a separate reportable segment (see Note 3 to the Consolidated Financial Statements), (2) to present the effects of additional discontinued operations as a result of the change within the Field Services reportable segment (see Note 12 to the Consolidated Financial Statements), (3) to revise certain financial statement captions related to Crescent (see Note 24 to the Consolidated Financial Statements), (4) to provide updates to significant litigation matters since the original filing date of March 15, 2004 (see Note 17 to the Consolidated Financial Statements), (5) to remove the presentation of consolidated earnings before interest and taxes (EBIT) pursuant to the Securities and Exchange Commission s rules on presentation of non-GAAP financial measures, and (6) to update for material subsequent events occurring since the original filing date of March 15, 2004 (see Note 23 to the Consolidated Financial Statements). These revisions did not affect consolidated net income, total assets, liabilities or stockholders equity.

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DUKE ENERGY CORPORATION

FORM 10-K/A FOR THE YEAR ENDED DECEMBER 31, 2003

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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 statemen 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

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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

Lack of improvement or further 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.

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Item 1. Business.

GENERAL

Duke Energy Corporation (collectively with its subsidiaries, Duke Energy) is a leading energy company located in the Americas with an affiliated real estate operation. Duke Energy provides its services through the business segments 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 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 throughout the East Coast and Southern U.S., the Pacific Northwest, and in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and gas transportation and processing services to customers in Western Canada. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission Corporation. Duke Energy Gas Transmission Corporation s natural gas transmission and storage operations in the U.S. are subject to the FERC s, the Texas Railroad Commission 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 subject to the rules and regulations of the National Energy Board (NEB) or the Ontario Energy Board (OEB).

Field Services gathers, compresses, treats, processes, transports, trades and markets, and stores natural gas; and produces, 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 natural gas from production wellheads in Western Canada and 10 states in the U.S. Those systems serve major natural gas-producing regions in the Western Canadian Sedimentary Basin, Rocky Mountain, Permian Basin, Mid-Continent and East Texas-Austin Chalk-North Louisiana areas, as well as onshore and offshore Gulf Coast areas.

DENA operates and manages merchant power generation facilities and engages in commodity sales and services related to natural gas and electric power around its generation assets and contractual positions. DENA conducts business throughout the U.S. and Canada generally through Duke Energy North America, LLC and Duke Energy Trading and Marketing, LLC (DETM). DETM is 40% owned by Exxon Mobil Corporation and 60% owned by Duke Energy. In 2003, Duke Energy discontinued the proprietary trading business at DENA, commenced actions to unwind DETM, and announced its intent to reduce its investment in merchant power generation facilities by selling its facilities in the Southeast U.S. and reducing its interests in partially constructed facilities in the Western U.S.

International Energy develops, 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.

During 2003, International Energy began the process to discontinue proprietary trading and is in the process of exiting its European and Australian operations.

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Beginning in 2004, Crescent, formerly part of Other Operations, is considered a separate reportable segment. All information for all the years presented within this report has been updated to show the impact of presenting Crescent as a separate reportable segment. Crescent develops high-quality commercial, residential and multi-family real estate projects, and manages legacy land holdings primarily in the Southeastern and Southwestern U.S.

All other entities previously included in Other Operations and now within Other still remain, primarily: DukeNet Communications, LLC (DukeNet), Duke Energy Merchants, LLC (DEM) and Duke/Fluor Daniel (D/FD). DukeNet develops and manages fiber optic communications systems for wireless, local and long-distance communications companies; and for selected educational, governmental, financial and health care entities. DEM is in the refined products business. During 2003, Duke Energy determined that it will exit the refined products business at DEM in an orderly manner, and is unwinding its portfolio of contracts. D/FD provides comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide. D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation. During 2003, Duke Energy and Fluor Corporation announced that the D/FD partnership will be dissolved. The D/FD partners have adopted a plan for an orderly wind-down of the business targeted for completion in July 2005. Also previously included in Other Operations was Energy Delivery Services, an engineering, construction, maintenance and technical services firm specializing in electric transmission and distribution lines and substation projects, until its sale in December 2003. Additionally, Duke Capital Partners, LLC, a wholly owned merchant finance company that provided debt and equity capital and financial advisory services primarily to the merchant energy industry, had been previously included in Other Operations, but is now classified as discontinued 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 Securities and Exchange Commission (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.

Allowance for Funds Used During Construction. 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.

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Derivative. A 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 and gains or losses are often settled net.

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

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.

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 fixed amount of a commodity at a predetermined price 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, etc.

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 ensures non-discriminatory access to a regional transmission system, providing all customers access to the power exchange and clearing all bilateral contract requests for use of the electric transmission system. Also responsible 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 260 degrees Fahrenheit.

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. The process whereby an asset or liability is recognized at fair value and the change in the fair value of that asset or liability is recognized in revenues in the Consolidated Statements of Operations or in Other Comprehensive Income within equity during the current period.

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 value chain.

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.

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.

Reliability Must Run. Generation that the California 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.

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

Tolling. Process whereby a party provides fuel to a power generator and receives kilowatt hours in return for a pre-established 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. Implied volatility is a measure of what the market values volatility to be, as reflected in the option s price.

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 financial information on Duke Energy s business segments, see Note 3 to the Consolidated Financial Statements, Business Segments.)

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FRANCHISED ELECTRIC

Service Area and Customers

Franchised Electric generates, transmits, distributes and sells electricity. It conducts operations primarily 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 92,000 miles of distribution lines and a 13,000 mile transmission system. Electricity is 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 buy power 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, the largest industry served by Franchised Electric, accounted for approximately $309 million of Franchised Electric s revenues for 2003, representing 6% of total electric revenues and 29% of industrial revenues. Franchised Electric normally experiences seasonal peak loads in summer and winter months.

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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 7,699 MW, 31 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 2,806 MW and seven combustion turbine stations with a combined capacity of 2,424 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, exchange of capacity and energy, and reliability of power supply. Franchised Electric expects that 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 with 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 2003, more than 97% of the total generated energy came from Franchised Electric s low cost, efficient nuclear and coal units (46.7% nuclear and 50.7% coal). The remainder of energy needs was supplied by hydro 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 fewer peak hour load periods (or 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, 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 which increased dramatically in 2003 as compared to the four previous drought years. Since these hydroelectric units can also be rapidly started or stopped, they are also used in peak periods when customer loads are rapidly changing so that system operators can match changing customer 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, 2003.

	Generation by Source (Percent)			Cost of Delivered Fuel per Net Kilowatt-hour Generated (Cents)		
	2003	2002	2001	2003	2002	2001

Coal	50.7	51.2	50.9	1.59	1.54	1.48
Nuclear(a)	46.7	48.3	48.6	0.42	0.42	0.42
Oil and gas(b)	0.1	0.1	0.2	15.52	11.89	11.48
All fuels (cost based on weighted average)(a)	97.5	99.6	99.7	1.05	1.01	0.98
Hydroelectric(c)	2.5	0.4	0.3			
	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.

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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 2004 to 2006. Duke Energy 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.

The average sulfur content of coal purchased by Franchised Electric is approximately 1%. This coal, coupled with utilization of available sulfur dioxide emission allowances on the open market 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 the 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 domestic suppliers on a plant by plant basis using multi-year contracts.

Based upon 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	2005	2005	2007	2006
McGuire	2005	2005	2007	2009
Catawba	2005	2005	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 Duke Power 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 and Webster, LLC from the U.S. government s excess plutonium in its nuclear weapons programs and is similar to conventional uranium fuel. Before using the fuel, Duke Energy must apply for and obtain amendments to the facilities operating licenses from the NRC. (See Note 18 to the Consolidated Financial Statements, Guarantees and Indemnifications, for additional information.)

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Insurance and Decommissioning

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 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 $10.9 billion. (See Note 17 to the Consolidated Financial Statements, Commitments and Contingencies Nuclear Insurance, for more information.)

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.9 billion in 1999 dollars, based on decommissioning studies completed in 1999 (studies are completed every five years). 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. Both the NCUC and the PSCSC have allowed Duke Energy to recover estimated decommissioning costs through rates over the expected remaining service periods of Duke Energy s nuclear stations.

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.

Competition

Duke Energy continues to monitor electric industry restructuring; however, movement toward retail deregulation has virtually stopped. (For more information, see Management s Discussion and Analysis of Results of Operations and Financial Condition, Current Issues Electric Competition.)

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. 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 some electric sales to wholesale customers, excluding the other joint owners of the Catawba Nuclear Station: those rates are set through contractual agreements. (For more

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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 affiliated entities. These regulations affect the activities of non-regulated affiliates with Franchised Electric.

The Energy Policy Act of 1992 and the FERC s subsequent rulemaking activities opened the wholesale energy market to competition. Open-access transmission for wholesale customers, as defined by the FERC s rules, provides energy suppliers, including Duke Energy, with opportunities to sell and deliver capacity and energy at market-based prices. From the FERC s open-access rule, Franchised Electric obtained the rights to sell capacity and energy at market-based rates from its own assets, which also allows Franchised Electric to purchase, at attractive rates, a portion of its capacity and energy requirements resulting in lower overall costs to customers. Open access also provides Franchised Electric s existing wholesale customers with competitive opportunities to seek other suppliers for their capacity and energy requirements.

In 1999 and 2000, the FERC issued its Order 2000 and Order 2000-A regarding RTOs. These orders set minimum characteristics and functions RTOs must meet, including independent authority to establish the terms and conditions of transmission service over the facilities they control. The orders provide for an open and flexible RTO structure to meet the needs of the market, and for the possibility of incentive ratemaking and other benefits for transmission owners that participate. The FERC proposes to have RTOs or other independent transmission providers operate transmission systems in all regions of the country.

As a result of these rulemakings, Duke Power and the franchised electric units of two other investor-owned utilities, Carolina Power & Light Company 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. The sponsors expected that GridSouth would be substantially operational by the FERC s Order 2000 deadline date of December 15, 2001. However, in July 2001 the FERC ordered GridSouth and other utilities in the Southeast to join in a mediation to negotiate terms of a southeastern RTO. It does not appear that the FERC will issue an order specifically based on that proceeding. In 2002, the GridSouth sponsors withdrew their applications to the NCUC and the PSCSC for approval of the transfer of functional control of their electric transmission assets to GridSouth, and announced that development of the GridSouth implementation project had been suspended until the sponsors have an opportunity to further consider regulatory circumstances. Duke Energy believes that more open wholesale electric markets will at some point provide benefits to consumers and other market participants. Duke Energy continues to examine options relative to RTOs in light of the existing complex regulatory environment. 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.

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Franchised Electric is subject to the jurisdiction of the Environmental Protection Agency (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 throughout the East Coast and Southern U.S., the Pacific Northwest, and in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and gas transportation and processing services to customers in Western Canada. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission Corporation.

For 2003, Natural Gas Transmission s proportional throughput for its pipelines totaled 3,362 trillion British thermal units (TBtu), compared to 3,160 TBtu in 2002, a 6% increase mainly due to the Westcoast Energy Incorporated (Westcoast) acquisition. 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. The operations purchased in the Westcoast acquisition contributed 1,396 TBtu in 2003, compared to 1,229 TBtu in 2002. 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, British Columbia, and the Pacific Northwest. (For detailed descriptions of Natural Gas Transmission s pipeline systems, see Properties Natural Gas Transmission)

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 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 U.S. Union Gas distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall. Union Gas distribution system consists of approximately 21,000 miles of distribution pipelines serving approximately 1.2 million residential, commercial and industrial customers.

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Natural Gas Transmission, through Market Hub Partners (MHP), wholly owns natural gas salt cavern facilities in south Texas and Louisiana with a total storage capacity of approximately 31 billion cubic feet (Bcf). MHP markets natural gas storage services to pipelines, LDCs, producers, end users and natural gas marketers. Texas Eastern Transmission, LP (Texas Eastern) and East Tennessee Natural Gas Company (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. Texas Eastern has two joint-venture storage facilities in Pennsylvania and one wholly owned and operated storage field in Maryland. Texas Eastern s certificated working capacity in these three fields is 75 Bcf. ETNG has an LNG storage facility in Tennessee with a certificated working capacity of 1.2 Bcf. Union Gas owns approximately 150 Bcf of natural gas storage capacity in 20 underground facilities located in depleted gas fields near Sarnia, Ontario.

Competition

Natural Gas Transmission s pipeline, storage and gas gathering and processing businesses compete with other pipeline and storage facilities in the transportation, processing and storage of natural gas. Natural Gas Transmission competes directly with other pipelines and storage facilities serving its market areas. Natural Gas Transmission also competes directly with other natural gas storage facilities in south Texas, Louisiana and Ontario. 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. As 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.

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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.

The FERC regulations restrict access to U.S. interstate pipeline natural gas transmission customer and other data by affiliated gas marketing entities, 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.

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 has developed new regulations, effective February 14, 2004, that establish mandatory inspections for all natural gas transmission pipelines in high-consequence areas within 10 years. 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 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 and the British Columbia Utilities Commission. These agencies have authorization similar to the FERC for setting 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 produces, 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 natural gas from production wellheads in Western Canada and ten states in the U.S. Those systems serve major gas-producing regions in the Western Canadian Sedimentary Basin, Rocky Mountain, Permian Basin, Mid-Continent and East Texas-Austin Chalk-North Louisiana areas, as well as onshore and offshore Gulf Coast areas. Field Services owns and operates approximately 58,000 miles of natural gas gathering systems with approximately 34,000 active receipt points.

Field Services natural gas processing operations separate raw natural gas that has been gathered on its systems and third-party systems into condensate, NGLs and residue gas. Field Services processes the raw natural gas at the 56 natural gas processing facilities that it owns and operates and at ten 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

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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 or 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 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 Waha, Texas; 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 marketing 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 also owns Texas Eastern Products Pipeline Company, LLC (TEPPCO), the general partner of TEPPCO Partners, L.P., a publicly traded limited partnership which owns one of the largest common carrier pipelines of refined petroleum products and liquefied petroleum gases in the U.S., 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.

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Field Services operating results are significantly impacted by changes in average NGL prices, which increased approximately 39% in 2003 compared to 2002. (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.)

Field Services activities can fluctuate in response to seasonal demand for natural gas.

Competition

Field Services competes with major integrated oil companies, major interstate and intrastate pipelines, national and local natural gas gatherers, and brokers, marketers and distributors for natural gas supplies, in gathering and processing natural gas and in marketing and transporting natural gas and NGLs. 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; whereas, competition for sales to customers is based primarily upon reliability, services offered, and price of delivered natural gas and NGLs.

Regulation

The intrastate pipelines owned by Field Services are subject to state regulation. To the extent they provide services under Section 311 of the Natural Gas Policy Act of 1978, the pipelines are also subject to FERC regulation. However, most of Field Services natural gas gathering 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.) Some of Field Services operations are subject to the jurisdiction of the Federal and state transportation agencies.

Recently, the DOT has developed new regulations, effective February 14, 2004, that require gas transmission pipeline operators to develop and implement integrity management programs for gas transmission pipelines located where a leak or rupture could have the greatest impact to life and property in areas referred to as high consequence areas. The regulations require gas pipeline transmission operators to perform ongoing assessments of pipeline integrity and to implement preventative and mitigative actions. Baseline integrity assessments are required to be completed by December 2012. Reassessments are to be conducted at prescribed intervals. Field Services is presently developing its implementation program to address these new DOT requirements, and is also evaluating the effects of complying with this new DOT regulatory program.

Field Services Canadian assets are regulated by the Alberta Energy and Utilities Board and the NEB.

DUKE ENERGY NORTH AMERICA

DENA operates and manages merchant power generation facilities and engages in commodity sales and services related to natural gas and electric power around its generation and contractual positions. DENA conducts business throughout the U.S. and Canada through Duke Energy North America and DETM. DETM is 40% owned by Exxon Mobil Corporation and 60% owned by Duke Energy. As discussed below, during 2003 certain key events led DENA to undertake a number of actions to change its existing business strategy.

As an active participant in the North American wholesale energy market, DENA has redefined its business strategy primarily in response to:

- Power generation oversupply in certain regions in the U.S., resulting in low spark spreads

- Reduction of major wholesale energy marketing and trading participants resulting in decreased market liquidity and increased collateral demands

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As a result of these market developments DENA:

- Executed substantial re-organization efforts, resulting in significant staff and annual cost reductions
- Discontinued proprietary trading and other non-core businesses
- Decided to exit the Southeast region
- Resolved to wind down the operations of DETM. The majority of the commodity contracts have been eliminated or sold to third parties. DENA will continue its participation in the market through 100% Duke Energy-owned entities.

In the fourth quarter 2003, management decided to: a) exit the Southeast region through a contemplated disposition of its merchant generation plants located in that region, b) not use Duke Energy funds to complete construction and reduce DENA s interest in deferred plants, and c) wind-down DETM. These actions negatively impacted operating income by approximately $3.1 billion.

Previously, DETM was committed to market substantially all of ExxonMobil s U.S. and Canadian natural gas production through 2006. Beginning in March 2003, most of this natural gas production was no longer made available to be marketed by DETM. This change in gas supply along with the other key market events described above prompted the wind-down of DETM. As stated above, the majority of DETM s commodity contracts have been eliminated or sold to third parties during 2003 and the remaining actions to wind-down DETM s operations will continue in 2004.

In June 2003, DENA sold its 50% ownership interest in Duke/UAE Ref-Fuel for $325 million to Highstar Renewable Fuels LLC. DENA recorded a gain on the sale of approximately $178 million, which is included in Gains on Sales of Equity Investments in the Consolidated Statements of Operations.

Generation Assets

DENA currently owns or operates approximately 15,820 net MW of operating generation and has approximately 2,402 net MW of operating generation under construction. During 2003, DENA determined that the partially constructed power generation facilities, Moapa, Grays Harbor, and Luna (collectively the deferred plants), will not be completed with Duke Energy funds. DENA will look to sell and/or solicit funding for completion of the deferred plants in 2004. Additionally, DENA has decided to sell all of its power generation facilities in the Southeast U.S.

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The following map shows DENA s power generation facilities.

Marketing Portfolio

The majority of DENA s portfolio of purchase and sales agreements incorporate market-sensitive pricing terms. Physical purchase and sales commitments involving significant price and location risk are generally hedged with financial derivatives. DENA s results may also fluctuate in response to seasonal demand for electricity, natural gas and other energy-related commodities. Additionally, weather has a significant impact on electricity and natural gas demand. (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.)

Customers

DENA markets electricity to investor-owned utilities, municipal power generators and other power marketers. DENA markets natural gas primarily to LDCs, electric power generators, municipalities, large industrial end-users and energy marketing companies. DENA also provides energy management services, such as supply and market aggregation, peaking services, dispatching, balancing, transportation, storage, tolling, contract negotiation and administration, as well as energy commodity risk management products and services.

Competition

DENA s competitors include utilities, other merchant electric generation companies in North America, certain financial institutions engaged in commodity trading, major integrated oil companies, major interstate pipelines and their marketing affiliates, brokers, marketers and distributors, and other domestic and international electric power and natural gas marketers. The price of commodities and services delivered, along with the quality and reliability of services provided, drive competition in the energy marketing business.

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Over the past two years, there has been a significant reduction in number of market participants due to the profitability decline resulting from oversupply of generation, increase in regulation, cost of capital to maintain generation facilities, collateral requirements, and bankruptcies. With fewer market participants, liquidity has been further depressed.

Regulation

DENA s energy marketing activities are, in some circumstances, subject to the jurisdiction of the FERC. Current FERC policies permit DENA s trading and marketing entities to market natural gas, electricity and other energy-related commodities at market-based rates, subject to FERC jurisdiction. DENA continues to monitor the varied pace of wholesale electricity market restructuring. (For more information, see Management s Discussion and Analysis of Results of Operations and Financial Condition, Current Issues Electric Competition.)

Certain of DENA s generating stations in California sell electricity to the California ISO under reliability must run agreements; those sales are made at FERC regulated rates. In addition, several legal and regulatory proceedings at the state and federal levels are ongoing related to DENA s activities in California during the electricity supply situation and related to trading activities. (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 will be subject to regulation pursuant to rules that are currently being promulgated by state authorities. The new rules are intended to increase the reliability of the generation supply in California by setting maintenance standards and regulating when plants may be taken out of service for routine maintenance. Duke Energy does not believe that the new rules, when finalized, 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 develops, 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.

During 2003, International Energy sold its interest in P.T. Puncakjaya Power in Indonesia as well as decided to exit the European market and sell its Australian assets. As a result, these operations are not included in International Energy s results but have been reclassified to discontinued operations for current and prior years. As of December 31, 2003, the European and Australian assets and liabilities are classified as Assets Held for Sale, and Liabilities Associated with Assets Held for Sale, respectively, on the Consolidated Balance Sheet. (See Note 12 to the Consolidated Financial Statements, Assets Held for Sale and Discontinued Operations for further discussion.)

From its platform of assets, International Energy provides customers with energy supply at competitive prices, manages the logistics associated with power and natural gas delivery, and offers services that allow customers to improve energy efficiency and hedge their commodity price exposure. International Energy s customers include retail distributors, electric utilities, independent power producers 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, controlling and reducing costs and divesting selected assets.

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International Energy s continuing operations owns, operates or has substantial interests in approximately 4,121 net MW of generation facilities. The following map shows the locations of International Energy s facilities, including projects under construction. The capacities shown in the map are gross MW values (for net MW values see Properties International Energy).

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 is 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 international environmental regulations. (See Environmental Matters in this section.)

CRESCENT

Beginning in 2004, Crescent, formerly part of Other Operations, is considered a separate reportable segment. Crescent develops high-quality commercial, residential and multi-family real estate projects, and manages land holdings, primarily in the Southeastern and Southwestern U.S. On December 31, 2003, Crescent owned 1.3 million square feet of commercial, industrial and retail space, with an additional 0.9 million square

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feet under construction. This portfolio included 1.4 million square feet of office space, 0.4 million square feet of warehouse space and 0.4 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 four multi-family communities at December 31, 2003, including two operating properties and two properties under development. On December 31, 2003, Crescent also managed approximately 134,000 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 with an inventory 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

Beginning in 2004, with the exception of Crescent, all other entities previously part of Other Operations as defined in Duke Energy s Form 10-K for December 31, 2003 and now within Other, still remain, primarily: DukeNet, DEM and D/FD. Unallocated corporate costs are also included in Other.

DukeNet provides telecommunications bandwidth capacity for industrial and commercial customers through its fiber optic network. It owns and operates a fiber optic communications network centered in North Carolina and South Carolina and is interconnected with a fiber optic communications network through affiliate agreements with third parties.

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. In 2003, Duke Energy determined that it will exit the refined products and NGL business at DEM in an orderly manner. DEM expects to complete the exit during 2004. The exiting process will include both a wind down of the current business and the selling of remaining long-term contracts. In 2003, DEM also sold Duke Energy Hydrocarbons LLC, and the related hydrocarbons activity was classified as discontinued operations.

D/FD, operating through several entities, provides full-service siting, permitting, licensing, engineering, procurement, construction, start-up, operating and maintenance services for fossil-fueled electric power plants, both domestically and internationally. Subsidiaries of Duke Energy and Fluor Corporation each own 50% of D/FD. In 2003, Duke Energy and Fluor Corporation announced that the D/FD partnership will be dissolved. The partners of D/FD have adopted a plan for an orderly wind-down of the D/FD business targeted for completion in July 2005.

Competition and Regulation

DEM competes for other energy-related commodities. Competitors include major integrated oil companies, major interstate pipelines and their marketing affiliates, brokers and distributors. D/FD competes with major companies who provide engineering, procurement, construction, start-up and maintenance services for fossil fueled power generation facilities.

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The entities within Other are subject to the jurisdiction of the EPA and international, 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 regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental matters. Environmental 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 emissions 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 treated wastewater into the environment.

- The Comprehensive Environmental Response, Compensation and Liability Act, which can require any individual or entity that may have owned or operated a disposal site, as well as transporters or generators of hazardous substances sent to such 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 consideration of potential environmental impacts by federal agencies 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 and Note 17 to the Consolidated Financial Statements, 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, 2003, Duke Energy had approximately 23,800 employees. A total of 3,124 operating and maintenance employees were represented by unions. This amount consists of the following:

1,214 employees represented by the International Brotherhood of Electrical Workers

1,039 employees represented by the Communications, Energy and Paperworkers of Canada

219 employees represented by the United Steel Workers of America

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186 employees represented by the Canadian Pipeline Employees Association

85 employees represented by Sindicato de Trabajadores del Sector Petroquimico

79 employees represented by Sindicato de Trabajadores del Sector Electrico

77 employees represented by Sindicato dos Trabalhadores na Industria da Energia Hidroeletrica de Ipaussu

63 employees represented by the International Union of Operating Engineers

29 employees represented by Asociacion del Personal Jerarquico del Agua y la Energia

25 employees represented by Sindicato Unico de Centrales de Generacion Canion del Pato

24 employees represented by Sindicato dos Trabalhadores na Industria de Energia Eletrica de Campinas

24 employees represented by Sindicato Unico de Generacion Electrica Carhuaquero

20 employees represented by Sindicato Corani

14 employees represented by Federacion Argentina de Trabajadores de Luz y Fuerza

11 employees represented by Sindicato dos Trabalhadores nas Industrias de Energia Eletrica de Sao Paulo

11 employees represented by the National Distribution Union

4 employees represented by the United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industries of the U.S. and Canada

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EXECUTIVE OFFICERS OF DUKE ENERGY

PAUL M. ANDERSON, 58, 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 CEO of PanEnergy Corp (PanEnergy).

KEITH G. BUTLER, 43, 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 Duke Energy North America in July 1998, and Chief Operating Officer of DukeSolutions in September 1999 before he assumed his current position in August 2001.

MYRON L. CALDWELL, 46, 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.

FRED J. FOWLER, 58, 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, 52, Group Vice President and Chief Financial Officer. Mr. Hauser assumed his current position in February 2004, but had been the Acting Chief Financial Officer since December 2003. He previously served as Senior Vice President and Treasurer. Mr. Hauser held various positions, including Controller, at Duke Power before being named Senior Vice President, Global Asset Development in 1997.

JIM W. MOGG, 55, 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.

RICHARD J. OSBORNE, 53, 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, 56, President, 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.

MARTHA B. WYRSCH, 46, Group Vice President, General Counsel and Secretary. Ms. Wyrsch was named to her current position in January 2004. She previously 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.

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Item 2. Properties.

FRANCHISED ELECTRIC

As of December 31, 2003, 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 7,699 MW, 31 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 2,806 MW and seven combustion turbine stations with a combined capacity of 2,424 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	2,240	2,240	Coal	NC	100
McGuire	2,200	2,200	Nuclear	NC	100
Marshall	2,090	2,090	Coal	NC	100
Lincoln CT	1,267	1,267	Natural gas/Fuel Oil	NC	100
Allen	1,140	1,140	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	573	573	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)	646	646	Hydro	NC/SC	100
Total	19,925	17,949			

In addition, Franchised Electric owned, as of December 31, 2003, 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 92,600 conductor miles of electric distribution lines, including 49,300 miles of rural overhead lines, 16,500 miles of urban overhead lines, 14,300 miles of rural underground lines and 12,500 miles of urban underground lines. As of December 31, 2003, 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.)

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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.

Algonquin Gas Transmission Company s (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. Algonquin is a wholly owned subsidiary of Duke Energy.

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.

Maritimes and Northeast Pipeline s transmission system (approximately 75% 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 of 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 distributes natural gas to 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 U.S. 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. Union Gas distribution system consists of approximately 21,000 miles of distribution.

MHP owns and operates two natural gas storage facilities: Moss Bluff and Egan. The Moss Bluff facility consists of three storage caverns located in Liberty and Chambers counties near Houston, Texas and has access to five pipelines. The Egan facility consists of three storage caverns located in Acadia Parish in the south central part of Louisiana and has access to seven pipeline facilities.

(For a map showing natural gas transmission and storage properties and additional information on Natural Gas Transmission s 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.)

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DUKE ENERGY NORTH AMERICA

The following table provides information about DENA s generation portfolio in operation as of December 31, 2003.

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
Murray(a)	1,240	1,240	Combined Cycle	Natural Gas	GA	100
Morro Bay	1,002	1,002	Combined Cycle	Natural Gas	CA	100
South Bay	700	700	Combined Cycle	Natural Gas	CA	100
Enterprise Energy(a)	640	640	Simple Cycle	Natural Gas	MS	100
Lee	640	640	Simple Cycle	Natural Gas	IL	100
Marshall(a)	640	640	Simple Cycle	Natural Gas	KY	100
Sandersville(a)	640	640	Simple Cycle	Natural Gas	GA	100
Southhaven(a)	640	640	Simple Cycle	Natural Gas	MS	100
Vermillion	640	640	Simple Cycle	Natural Gas	IN	100
Fayette	620	620	Combined Cycle	Natural Gas	PA	100
Hot Springs(a)	620	620	Combined Cycle	Natural Gas	AR	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
Hinds(a)	520	520	Combined Cycle	Natural Gas	MS	100
Maine Independence	520	520	Combined Cycle	Natural Gas	ME	100
St. Francis	500	250	Combined Cycle	Natural Gas	MO	50
Bridgeport	490	326	Combined Cycle	Natural Gas	CT	67
New AlbanyEnergy(a)	385	385	Simple Cycle	Natural Gas	MS	100
Bayside	260	195	Combined Cycle	Natural Gas	NB	75
Oakland	165	165	Simple Cycle	Oil	CA	100
McMahon	117	59	Cogen	Natural Gas	BC	50
Ft. Francis	110	110	Cogen	Natural Gas	ON	100
Total	16,657	15,820				

(a) Southeast region

(For a map showing DENA s properties, see Business Duke Energy North America earlier in this section.)

INTERNATIONAL ENERGY

The following table provides information about International Energy s generation portfolio in operation as of December 31, 2003

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
Acajutla	324	293	Oil/Diesel	El Salvador	90
Electroquil	180	130	Diesel	Ecuador	72
DEI Guatemala y Cia	328	328	Oil/Diesel	Guatemala	100
Aquaytia	160	61	Natural Gas	Peru	38
Empressa Electrica Corani	126	63	Hydro	Bolivia	50
Total(a)	4,541	4,121			

(a) Excludes discontinued operations

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(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.

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 2003.

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PART II.

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 27, 2004, there were approximately 147,900 common stockholders of record.

Common Stock Data by Quarter

	2003			2002		
	Dividends Per Share	Stock Price Range(a) High	Stock Price Range(a) Low	Dividends Per Share	Stock Price Range(a) High	Stock Price Range(a) Low
First Quarter	$ 0.275	$ 21.57	$ 12.21	$ 0.275	$ 40.00	$ 31.99
Second Quarter	0.550	20.75	13.51	0.550	39.60	28.50
Third Quarter		19.70	16.75		31.10	17.81
Fourth Quarter	0.275	20.89	17.08	0.275	22.00	16.42

(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 every three years.

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Item 6. Selected Financial Data.(d)

	2003(b)(d)	2002(d)	2001(d)	2000(d)	1999(d)
	(in millions, except per share amounts)				
Statement of Operations					
Operating revenues	$ 22,154	$ 15,898	$ 17,946	$ 15,970	$ 9,618
Operating expenses	22,872	13,295	14,367	12,934	8,163
Gains on sales of investments in commercial and multi-family properties	84	106	106	75	116
(Losses) gains on sales of other assets, net	(199)	32	238	214	132
Operating (loss) income	(833)	2,741	3,923	3,325	1,703
Other income and expenses, net	556	379	311	707	314
Interest expense	1,380	1,097	760	887	583
Minority interest expense	61	116	326	305	141
(Loss) earnings from continuing operations before income taxes	(1,718)	1,907	3,148	2,840	1,293
Income tax (benefit) expense from continuing operations	(709)	611	1,149	1,035	456
(Loss) income from continuing operations	(1,009)	1,296	1,999	1,805	837
(Loss) income from discontinued operations, net of tax	(152)	(262)	(5)	(29)	10
(Loss) income before extraordinary item and cumulative effect of change in accounting principle	(1,161)	1,034	1,994	1,776	847
Extraordinary gain, net of tax					660
Cumulative effect of change in accounting principle, net of tax and minority interest	(162)		(96)		
Net (loss) income	(1,323)	1,034	1,898	1,776	1,507
Dividends and premiums on redemption of preferred and preference stock	15	13	14	19	20
(Loss) earnings available for common stockholders	$ (1,338)	$ 1,021	$ 1,884	$ 1,757	$ 1,487
Ratio of Earnings to Fixed Charges	(c)	2.2	3.9	3.7	2.8
Common Stock Data(a)					
Shares of common stock outstanding					
Year-end	911	895	777	739	733
Weighted average	903	836	767	736	729
(Loss) earnings per share (from continuing operations)					
Basic	$ (1.13)	$ 1.53	$ 2.59	$ 2.43	$ 1.12
Diluted	(1.13)	1.53	2.57	2.42	1.12
(Loss) earnings per share (from discontinued operations)					
Basic	$ (0.17)	$ (0.31)	$ (0.01)	$ (0.04)	$ 0.01
Diluted	(0.17)	(0.31)	(0.01)	(0.04)	0.01
(Loss) earnings per share (before extraordinary item and cumulative effect of change in accounting principle)					
Basic	$ (1.30)	$ 1.22	$ 2.58	$ 2.39	$ 1.13
Diluted	(1.30)	1.22	2.56	2.38	1.13
(Loss) earnings per share					
Basic	$ (1.48)	$ 1.22	$ 2.45	$ 2.39	$ 2.04
Diluted	(1.48)	1.22	2.44	2.38	2.03
Dividends per share	1.10	1.10	1.10	1.10	1.10
Balance Sheet					
Total assets	$ 56,203	$ 60,122	$ 49,624	$ 59,276	$ 34,388
Long-term debt, less current maturities	20,622	20,221	12,321	10,717	8,683

(a) Amounts prior to 2001 were restated to reflect the two-for-one common stock split effective January 26, 2001.

(b) As of January 1, 2003, Duke Energy adopted the remaining provisions of Emerging Issues Task Force Issue No. 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and for Contracts Involved in Energy Trading and Risk Management Activities and Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. In accordance with the transition guidance for these standards, Duke Energy recorded a net-of-tax and minority interest cumulative effect adjustment for change in accounting principles. 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 $1,715 million for the year ended December 31, 2003.

(d) Certain amounts have been revised. See Note 24 to the Consolidated Financial Statements.

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

INTRODUCTION

Management s Discussion and Analysis includes the effects of revisions in order to (1) present Duke Energy s real estate operations, Crescent Resources, LLC (Crescent), as a separate reportable segment (see Note 3 to the Consolidated Financial Statements), (2) to present the effects of additional discontinued operations as a result of the change within the Field Services reportable segment (see Note 11 to the Consolidated Financial Statements), (3) to revise certain financial statement captions related to Crescent (see Note 24 to the Consolidated Financial Statements), (4) to provide updates to significant litigation matters since the original filing date of March 15, 2004 (see Note 17 to the Consolidated Financial Statements), (5) to remove the presentation of consolidated earnings before interest and taxes (EBIT) pursuant to the Securities and Exchange Commission s rules on presentation of non-GAAP financial measures, and (6) to update for material subsequent events occurring since the original filing date of March 15, 2004 (see Note 23 to the Consolidated Financial Statements). These revisions did not affect consolidated net income, total assets, liabilities or stockholders equity.

Management s Discussion and Analysis should be read in connection with the Consolidated Financial Statements.

Overview of Business Strategy and Economic Factors. Duke Energy s business strategy is to develop integrated energy businesses in targeted regions where Duke Energy s capabilities in developing energy assets; operating power plants, natural gas liquid (NGL) plants and natural gas pipelines; optimizing commercial operations (including its affiliated real estate operation); and managing risk can provide comprehensive energy solutions for customers and create value for shareholders.

The energy industry and Duke Energy are experiencing 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 current challenges, Duke Energy is focusing on reducing risks and restructuring its business to be well positioned as the energy marketplace regains its health and vigor. In 2003, Duke Energy established a platform for future growth by selling certain non-strategic assets, cutting expenses and paying down debt, while still funding capital expenditures at the core regulated Franchised Electric and Natural Gas Transmission businesses. Duke Energy also resolved many outstanding legal and regulatory issues; reduced the scope of its international operations by announcing its intention to exit the Australian and European markets; and repositioned Duke Energy North America (DENA) to be a more focused, asset-backed merchant business. The repositioning of DENA included discontinuing proprietary trading and announcing its intentions to exit the merchant generation business in the Southeast region.

Duke Energy s current goals for 2004 include: positive net cash generation; investing in its strongest businesses such as Franchised Electric, Natural Gas Transmission and Crescent; continuing to size its businesses to market realities; addressing merchant energy issues; strengthening relationships with customers; and further reducing regulatory and legal uncertainty. A major focus for 2004 will be to complete the execution of the plans Duke Energy announced for its merchant and international business, including the sale of its assets in the Southeastern U.S and Australia, and its exit from Europe. Duke Energy also plans to preserve its dividend payout of $1.10 per share and to continue to pay down debt in 2004 by $3.5 to $4.0 billion to further strengthen its balance sheet. (Included in the expected 2004 debt reduction amount is approximately $900 million of Australian dollar denominated debt related to International Energy s Australian operations.) Duke Energy believes it is well-positioned to generate cash in 2004 from operations, the settlement of the forward stock purchase component of the outstanding equity units, and from asset sales to meet its goals of reducing debt, paying the dividend and providing for maintenance and modest expansion.

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

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businesses like DENA, International Energy and Field Services. Additionally, Crescent s portfolio strategy is diversified between residential, commercial and multi-family development. Although Duke Energy expects to return to profitability in 2004, all of its 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 2004.

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 an impairment. The largest impairments over the past two years have been related to DENA and International Energy and it is estimated that the most significant future risk of impairments also resides within these segments.

Duke Energy and its goals for 2004 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 are 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 U.S. 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-U.S. 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 satisfied 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 2003 and 2002

Year Ended December 31, 2003 as Compared to December 31, 2002. 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. For 2002, earnings available for common stockholders were $1,021 million, or earnings of $1.22 per basic and diluted share. For Duke Energy, 2003 was a year of transition and one of Duke Energy s key goals was to establish a

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platform for future growth by cutting costs, selling non-strategic assets and exiting businesses that were not profitable or were not part of the core business. As a result, Duke Energy incurred significant charges in 2003 related to these activities; including wind-down costs, asset impairments and other charges related to current market conditions and strategic actions taken by management. Significant charges that contributed to the lower results in 2003 included:

- Charges of $2.8 billion related to asset impairment of DENA s Southeastern plants and its deferred Western plants, and wind-down costs associated with the Duke Energy Trading and Marketing, LLC (DETM) joint venture
- Charges of $262 million for the disqualification of certain hedges from the accrual method of accounting to mark-to-market accounting that were related to the impaired assets at DENA
- Charges and impairments of $292 million for International Energy s Australian and European businesses, which have been classified as discontinued operations
- A charge of $254 million for goodwill impairment at DENA, related primarily to the trading and marketing business
- Net losses of $199 million on other assets sold or held for sale
- Severance and related charges of $153 million associated with workforce reductions across all segments
- A charge of $51 million for the write-off of an abandoned corporate risk management information system

Partially offsetting these 2003 charges were net gains of $279 million on equity investment sales during the year, and when compared to 2002, $645 million of charges in 2002 related to severance, goodwill impairment for International Energy s European trading and marketing business, the termination of certain turbines on order, impairments of other uninstalled turbines, write-off of project and site development costs, demobilization costs related to deferred plants and a partial impairment of a merchant plant. (For additional information on goodwill impairments, other impairments and related charges, assets held for sale and discontinued operations, see Notes 9, 11 and 12 to the Consolidated Financial Statements)

Other key drivers of the 2003 lower results included:

- Increased interest expense of $283 million due primarily to decreased capitalized interest and higher average debt balances, primarily resulting from debt assumed in, and issued with respect to, the acquisition of Westcoast Energy Inc. (Westcoast)
- Charges related to changes in accounting principles of $162 million, net of tax and minority interest (see Note 1 to the Consolidated Financial Statements)
- Increased amortization expense of $115 million at Franchised Electric related to North Carolina clean air legislation (see Note 4 to the Consolidated Financial Statements)

A regulatory action by the Public Service Commission of South Carolina (PSCSC) which resulted in decreased earnings of $46 million at Franchised Electric, $16 million of which was an order to write-off regulatory assets related to debt issuance costs through interest expense (see Note 4 to the Consolidated Financial Statements)

International Energy s reserve and charges for environmental settlements with Brazil of $26 million

A settlement with the Commodity Futures Trading Commission (CFTC) of $17 million, net of minority interest expense, by DENA (see Note 17 to the Consolidated Financial Statements)

Milder weather which negatively impacted operations at DENA and Franchised Electric

Foregone earnings of assets and equity investments sold

The above decreases in earnings were partially offset by additional earnings in 2003 from the Westcoast acquisition in March 2002.

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Year Ended December 31, 2002 as Compared to December 31, 2001. In 2002, earnings available for common stockholders were $1,021 million, or $1.22 per basic and diluted share, compared to $1,884 million, or $2.45 per basic share and $2.44 per diluted share, in 2001. The decrease was due primarily to:

- Decreased trading and marketing results, due primarily to negative impacts of a prolonged economic downturn, low commodity prices, low volatility levels, reduced sparks spreads and decreased market liquidity
- Charges at several business units, such as asset impairments and severance costs, related to market conditions in 2002 and strategic actions taken by management
- A decline in the average price realized for electricity generated by Duke Energy s merchant plants
- An increase in interest expense due primarily to the debt assumed in the acquisition of Westcoast

The above drivers were partially offset by:

- Increased transportation, storage and distribution income from assets acquired or consolidated as a part of the acquisition of Westcoast in March 2002
- A one-time net-of-tax charge in 2001 of $96 million, or $0.13 per basic share, related to the cumulative effect of a change in accounting principle for the January 1, 2001 adoption of Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities

For additional information on specific business unit related items, see the segment discussions that follow. For a detailed discussion of interest, taxes and the change 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, 2003 as Compared to December 31, 2002. Consolidated operating revenues for 2003 increased $6,256 million, compared to 2002. This change was driven by a $5,368 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.

Regulated Natural Gas revenues also increased $742 million due primarily to increased transportation, storage and distribution revenues from assets acquired or consolidated as a part of the acquisition of Westcoast in March 2002.

Year Ended December 31, 2002 as Compared to December 31, 2001. Consolidated operating revenues for 2002 decreased $2,048 million, compared to 2001. The decrease was due primarily to decreased trading and marketing net margins (included in Non-regulated Electric, Natural Gas, Natural Gas Liquids, and Other revenues on the Consolidated Statements of Operations) as a result of the negative impacts of a prolonged economic weakness, low commodity prices, continued low volatility levels, reduced spark spreads and decreased market liquidity. The decrease was also a result of decreased revenues on the sale of natural gas, NGLs and other petroleum products. The decrease was partially offset by increased transportation, storage and distribution revenue from assets acquired or consolidated as part of the Westcoast acquisition in March 2002.

For a more detailed discussion of operating revenues, see the segment discussions that follow.

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Consolidated Operating Expenses

Year Ended December 31, 2003 as Compared to December 31, 2002. Consolidated operating expenses for 2003 increased $9,577 million, compared to 2002. Changes in consolidated operating expenses were driven primarily by asset impairments and 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.

Year Ended December 31, 2002 as Compared to December 31, 2001. Consolidated operating expenses for 2002 decreased $1,072 million, compared to 2001. The decrease was due primarily to a reduction in expenses related to the purchases of natural gas, NGLs and other petroleum products. The decrease was partially offset by increased operating expenses from assets acquired or consolidated as part of the Westcoast acquisition in March 2002, and various asset impairment and severance charges related to market conditions and strategic actions taken by management.

For a more detailed discussion of operating expenses, see the segment discussions that follow.

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 $84 million in 2003, and $106 million in 2002 and 2001. 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 $199 million for 2003, a gain of $32 million for 2002, and a gain of $238 million for 2001. The loss for 2003 was 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 Duke Energy 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. The gain for 2001 was primarily comprised of gains on sales of DENA s interests in several merchant energy facilities.

Consolidated Operating Income

Year Ended December 31, 2003 as Compared to December 31, 2002. For 2003, consolidated operating income decreased $3,574 million, compared to 2002. Lower operating income was driven by decreased operating income at DENA of $3,699 million, due primarily to asset impairments and related charges, as discussed above.

Year Ended December 31, 2002 as Compared to December 31, 2001. Consolidated operating income for 2002 decreased $1,182 million, compared to 2001. The decrease was driven by a $1,430 million decrease at DENA due to decreased trading and marketing results (as previously described), decreased average prices realized on electric generation, and certain charges taken as a result of 2002 market conditions and strategic actions by management. Also contributing to the decrease was a $314 million decrease at Field Services due to decreased commodity prices such as NGLs and natural gas. Slightly offsetting these decreases was a $488 million increase at Natural Gas Transmission due primarily to the acquisition of Westcoast in March 2002.

For a more detailed discussion of these variances, see segment discussions below.

Consolidated Other Income and Expenses

Other Income and Expenses increased $177 million for the year ended December 31, 2003 and $68 million for the year ended December 31, 2002. The increase for 2003 was driven primarily by DENA s $178 million gain on the sale of its 50% ownership interest in Duke/UAE Ref-Fuel LLC (Ref-Fuel) in June 2003 and Natural

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Gas Transmission s $90 million gain on sales of various investments in 2003, offset by foregone earnings from the sale of those investments. The increase for 2002 was driven by Natural Gas Transmission s $32 million gain on the sale of a portion of its partnership interests in Northern Border Partners L.P. in 2002.

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 excludes discontinued operations and 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 and cash equivalents are managed centrally by Duke Energy. Since the business units do not manage those items, the gains and losses on foreign currency remeasurement associated with cash balances, and third-party interest income on those balances, are generally 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.

EBIT is viewed as a non-Generally Accepted Accounting Principle (GAAP) measure under the rules of the Securities and Exchange Commission (SEC). EBIT should not be considered an alternative to, or more meaningful than, net income or operating cash flow as determined in accordance with GAAP. Duke Energy s 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,		
	2003	2002	2001
		(in millions)	
Franchised Electric	$ 1,403	$ 1,595	$ 1,626
Natural Gas Transmission	1,317	1,161	607
Field Services	186	149	334
Duke Energy North America	(3,341)	169	1,487
International Energy	210	102	236
Crescent	133	158	167
Total reportable segment EBIT	(92)	3,334	4,457
Other	(272)	(368)	(539)
Total reportable segment and other EBIT	(364)	2,966	3,918
Minority interest expense and other(a)	26	38	(10)
Interest expense	(1,380)	(1,097)	(760)
Consolidated (loss) earnings from continuing operations before income taxes	$ (1,718)	$ 1,907	$ 3,148

(a) Includes interest income, foreign currency remeasurement gains and losses, and additional minority interest expense not allocated to the segment results.

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The amounts discussed below include intercompany transactions that are eliminated in the Consolidated Financial Statements.

Franchised Electric

	Years Ended December 31,		
	2003	2002	2001
	(in millions, except where noted)		
Operating revenues	$ 4,883	$ 4,888	$ 4,746
Operating expenses	3,533	3,329	3,185
Gains on sales of other assets, net	6		
Operating income	1,356	1,559	1,561
Other income, net of expenses	47	36	65
EBIT	$ 1,403	$ 1,595	$ 1,626
Sales, Gigawatt-hours (GWh)	82,828	83,783	79,685

The following table shows the changes in GWh sales and average number of customers for Franchised Electric for the past two years.

Increase (decrease) over prior year	2003	2002
Residential sales(a)	(2.3)%	5.2%
General service sales(a)	0.4%	2.4%
Industrial sales(a)	(5.7)%	(2.4)%
Wholesale sales	5.1%	35.4%
Total Franchised Electric sales(b)	(1.1)%	5.1%
Average number of customers	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, 2003 as Compared to December 31, 2002

Operating Revenues. Operating revenues for 2003 decreased $5 million, compared to 2002. 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 (see Note 4 to the Consolidated Financial Statements)

A $28 million decrease in sales to industrial customers, which continued to decline due to the sluggish economy in North Carolina and South Carolina

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).

A $38 million increase due to continued growth in the number of residential and general service customers in Franchised Electric s service territory

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Operating Expenses. Operating expenses for 2003 increased $204 million, compared to 2002. 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 (see Note 4 to the Consolidated Financial Statements)
- 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
- 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
- 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.

Matters Impacting Future Franchised Electric s 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, but this growth will be offset by a continuing decline in the industrial sector. Franchised Electric s compounded annual EBIT growth over the next three years is expected to be 0% to 2%, coupled with strong cash flows. Changes in weather, wholesale power market prices and changes to the regulatory environment could impact future financial results for Franchised Electric. In addition, Franchised Electric s results will be affected by Duke Energy s flexibility to vary the amortization expenses associated with the North Carolina clean air legislation as noted in Operating Expenses above.

Year Ended December 31, 2002 as Compared to December 31, 2001

Operating Revenues. Operating revenues for 2002 increased $142 million, compared to 2001. The increase was driven primarily by:

- A $130 million increase from increased GWh sales to retail customers, driven by favorable weather in the latter half of 2002

A $40 million increase from continued growth in the number of residential and general service customers in Franchised Electric s service territory

A $36 million reduction in 2001 revenues resulting from a refinement in the estimates used to calculate unbilled kilowatt-hour sales

A $45 million decrease in wholesale power sales, primarily driven by lower prices in 2002

A $35 million decrease from decreased GWh sales to industrial customers as a result of a slow economy in North Carolina and South Carolina

Operating Expenses. Operating expenses for 2002 increased $144 million, compared to 2001. The increase was driven primarily by:

Expenses totaling $89 million associated with an ice storm in December 2002

Increased fuel costs of $54 million, resulting from the increase in electric sales

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A $36 million charge in 2002 for severance costs related to workforce reductions

Lower operating and maintenance expenses of $20 million at Franchised Electric s generating plants

Other Income, net of expenses. Other income, net of expenses decreased $29 million in 2002, compared to 2001, due primarily to a $19 million charge resulting from the settlement agreements reached with the North Carolina Utilities Commission (NCUC) and the PSCSC. (See Note 4 to the Consolidated Financial Statements.)

EBIT. EBIT for 2002 decreased $31 million, compared to 2001, primarily as a result of increased operating expenses, including costs associated with an ice storm in December 2002, severance costs related to workforce reductions, and charges resulting from the settlement agreements reached by Duke Energy with the NCUC and the PSCSC. The increase in operating expenses was offset by increases in revenues as discussed above.

Natural Gas Transmission

	Years Ended December 31,		
	2003	**2002**	**2001**
	(in millions, except where noted)		
Operating revenues	$ 3,197	$ 2,464	$ 1,060
Operating expenses	1,969	1,420	504
Gains on sales of other assets, net	7		
Operating income	1,235	1,044	556
Other income, net of expenses	125	148	51
Minority interest expense	43	31	
EBIT	$ 1,317	$ 1,161	$ 607
Proportional throughput, TBtu(a)	3,362	3,160	1,781

(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, 2003 as Compared to December 31, 2002

Operating Revenues. Operating revenues for 2003 increased $733 million, compared to 2002. 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)

A $177 million increase due to foreign exchange favorably impacting revenues from the Canadian operations as a result of the strengthening Canadian dollar

An $81 million increase from recovery of natural gas commodity costs that are passed through to customers without a mark-up at Union Gas Limited (Union Gas). This amount is offset in expenses.

A $31 million increase from completed and operational business expansion projects in the U.S.

A $58 million decrease from operations sold in 2003 and the fourth quarter of 2002 (see Note 2 to the Consolidated Financial Statements)

Operating Expenses. Operating expenses for 2003 increased $549 million, compared to 2002. 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

An $81 million increase related to increased natural gas prices at Union Gas. This amount is offset in revenues.

A $20 million increase from 2003 severance charges related to workforce reductions

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. Other income, net of expenses decreased $23 million for 2003, compared to 2002. 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 the Gulfstream Natural Gas System, LLC (Gulfstream), 50% owned by Duke Energy which went into service in May 2002

A $58 million increase in gains from the sale of various equity investments in 2003 (see Note 2 to the Consolidated Financial Statements)

A $17 million increase in allowance for funds used during construction related to additional capital projects

Minority Interest Expense. Minority interest expense increased $12 million for 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 100% owned subsidiaries acquired in the March 2002 acquisition of Westcoast.

EBIT. EBIT for 2003 increased $156 million, 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.

Matters Impacting Future Natural Gas Transmission s 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 2003 EBIT. The average contract life for the U.S. pipelines is nine years. Changes in the Canadian dollar, weather, throughput and the ability to renew service contracts would impact future financial results at Natural Gas Transmission.

Year Ended December 31, 2002 as Compared to December 31, 2001

Operating Revenues. Operating revenues for 2002 increased $1,404 million, compared to 2001. This increase resulted primarily from increased transportation, storage, and distribution revenue of $1,380 million from assets acquired or consolidated as a part of the Westcoast acquisition in March 2002. Revenues also increased $35 million due to business expansion projects.

Operating Expenses. Operating expenses for 2002 increased $916 million, compared to 2001. This increase was driven primarily by:

- Incremental operating expenses of $877 million related to the gas transmission, storage and distribution assets acquired or consolidated in the Westcoast acquisition in March 2002
- Severance costs of $9 million associated with a workforce reduction in 2002
- Incremental operating expenses associated with business expansion projects
- Reversal of reserves of $25 million related to certain environmental issues that were resolved in 2002
- Reduced goodwill amortization of $14 million in 2002 as a result of the implementation of SFAS No. 142, Goodwill and Other Intangible Assets

Other Income, net of expenses. Other income, net of expenses increased $97 million in 2002, compared to 2001, partly as a result of a $28 million construction fee from an unconsolidated affiliate related to the successful completion of the Gulfstream project in 2002 and associated incremental earnings of $19 million. Also contributing to the increase in other income was a $32 million gain in 2002 on the sale of a portion of Natural Gas Transmission s limited partnership units in Northern Border Partners, L.P. and an increase in allowance for funds used during construction related to capital projects.

Minority Interest Expense. Minority interest expense for 2002 resulted from consolidating less than 100% owned subsidiaries acquired in the March 2002 acquisition of Westcoast.

EBIT. EBIT for 2002 increased $554 million, compared to 2001. As discussed above, this increase resulted primarily from incremental EBIT related to assets acquired or consolidated as part of the acquisition of Westcoast in March 2002. EBIT was also impacted by a construction fee from an unconsolidated affiliate related to the successful completion of Gulfstream, and incremental earnings from Gulfstream which went into service in May 2002. EBIT was impacted, to a lesser extent, by the reversal of reserves as a result of the resolution of certain environmental issues during 2002 and the implementation of SFAS No. 142, resulting in the elimination of goodwill amortization.

Field Services

	Years Ended December 31,		
	2003	**2002**	**2001**
	(in millions, except where noted)		
Operating revenues	$ 8,661	$ 5,990	$ 8,341
Operating expenses	8,428	5,854	7,891
Losses on sales of other assets, net	(4)		

Operating income	229	136	450
Other income, net of expenses	67	60	45
Minority interest expense	110	47	161
EBIT	$ 186	$ 149	$ 334
Natural gas gathered and processed/transported, TBtu/d (a)	7.5	8.0	8.2
NGL production, MBbl/d (b)	359.1	384.4	390.0
Average natural gas price per MMBtu (c)	$ 5.39	$ 3.22	$ 4.27
Average NGL price per gallon (d)	$ 0.53	$ 0.38	$ 0.45

(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

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Year Ended December 31, 2003 as Compared to December 31, 2002

Operating Revenues. Operating revenues for 2003 increased $2,671 million, compared to 2002. The increase was due primarily to a $2.17 per MMBtu increase in average natural gas prices of approximately $2,250 million and a $0.15 per gallon increase in average NGL prices of approximately $1,195 million. Lower throughput and NGL production partially offset higher revenues by approximately $120 million related to natural gas volume and approximately $380 million related to lower NGL production. The results of cash flow hedging also partially offset higher revenues by approximately $179 million, as hedge contracts locked in an average MMBtu price below market.

Operating Expenses. Operating expenses for 2003 increased $2,574 million, compared to 2002. The increase was due primarily to increased costs of raw natural gas and natural gas liquids supply of approximately $2,985 million, offset by lower throughput volumes of approximately $440 million. Other factors contributing to higher operating expenses included severance charges in 2003 and other employee related expenditure increases totaling approximately $36 million.

Offsetting increases in operating expenses were 2002 charges related to Field Services internal review of balance sheet accounts of approximately $53 million ($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 $63 million in 2003, compared to 2002, due to increased earnings from Duke Energy Field Services, LLC (DEFS), Duke Energy s joint venture with ConocoPhillips. 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.

EBIT. EBIT for 2003 increased $37 million compared to the same period in 2002, as a result of better pricing and other factors discussed above.

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 organic growth. Field Services estimates 8% to 10% compounded annual EBIT growth over the next three years. However, 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.

In 2003, DEFS converted a portion of their keep whole contracts to add a minimum fee clause to the keep whole contract and/or converted the contracts to percent of proceeds contracts. This had the impact of reducing DEFS exposure to natural gas prices and reducing the exposure to NGL prices on an unhedged basis. After considering the impacts of hedging, DEFS exposure to a one cent per gallon change in the average price of NGLs is $6 million for 2004 and $7 million for 2003.

Year Ended December 31, 2002 as Compared to December 31, 2001

Operating Revenues. Operating revenues for 2002 decreased $2,351 million, compared to 2001. The decrease was due primarily to a $1.05 per MMBtu decrease in average natural gas prices and a decrease in average NGL prices of approximately $0.07 per gallon. Other factors contributing to lower operating revenues were reduced levels of natural gas gathered and processed/transported (throughput) of 0.2 TBtu per day, and a lower trading and marketing net margin as a result of market conditions.

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Operating Expenses. Operating expenses for 2002 decreased $2,037 million, compared to 2001. The decrease was due primarily to a decrease in average natural gas prices of $1.05 per MMBtu, a $0.07 per gallon decrease in average NGL prices and lower throughput levels. Partially offsetting these decreases were increases in operating and maintenance costs and general administrative costs of $113 million, resulting from increased maintenance on equipment, pipeline integrity and core business process improvements. Additionally, Field Services recorded, as part of its internal review of balance sheet accounts, approximately $53 million of charges ($37 million at Duke Energy s 70% share) in 2002, as described above.

Minority Interest Expense. Minority interest at Field Services decreased $114 million in 2002, compared to 2001, due primarily to decreased earnings from DEFS, Duke Energy s joint venture with ConocoPhillips. The decrease in minority interest expense was not proportionate to the decrease 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.

EBIT. EBIT for 2002 decreased $185 million, compared to 2001, primarily as a result of the changes in commodity prices and increases in operating, and general and administrative costs.

Duke Energy North America

	Years Ended December 31,		
	2003	**2002**	**2001**
	(in millions, except where noted)		
Operating revenues	$ 4,321	$ 1,552	$ 3,014
Operating expenses and impairments	7,767	1,507	1,768
(Losses) gains on sales of other assets, net	(208)		229
Operating (loss) income	(3,654)	45	1,475
Other income, net of expenses	206	81	56
Minority interest (benefit) expense	(107)	(43)	44
EBIT	$ (3,341)	$ 169	$ 1,487
Actual plant production, GWh (a)	24,046	24,962	20,516
Proportional megawatt capacity in operation	15,820	14,157	6,799

(a) Includes plant production from plants accounted for under the equity method

Year Ended December 31, 2003 as Compared to December 31, 2002

Operating Revenues. Operating revenues for 2003 increased $2,769 million, compared to 2002. 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.

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

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

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Operating Expenses and Impairments. Operating expenses and impairments for 2003 increased $6,260 million, compared to 2002. 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 Southeastern plants and its deferred 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 merchant power projects of $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

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 anticipated sale of the 25% net interest in Vermillion, a $66 million loss on the anticipated 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 $125 million for 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

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

Remaining decrease due primarily to lower equity earnings from Ref Fuel

Minority Interest Expense. Minority interest benefit increased $64 million for 2003 compared to 2002, due to increased losses at DETM.

EBIT. EBIT for 2003 decreased $3,510 million, 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.

Matters Impacting Future DENA Results

Power generation oversupply in certain regions in the U.S. has resulted in reduced spark spread in many markets. In addition the reduction of major wholesale marketing and trading participants has resulted in a decrease in overall power and gas market liquidity. DENA has reduced its merchant exposure and has simplified its business strategy to reposition DENA to maximize the value of its assets focusing on natural gas and power.

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If negative market conditions persist over time and estimated cash flows over the lives of DENA s individual assets do not exceed the carrying value of those individual assets, asset impairments may occur in the future. 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 impact an impairment analysis. As of December 31, 2003, DENA had written off all of its goodwill but had $4,386 million in total net property, plant and equipment (including the Southeastern U.S. plants), and $164 million in assets held for sale.

Year Ended December 31, 2002 as Compared to December 31, 2001

Operating Revenues. Operating revenues for 2002 decreased $1,462 million, compared to 2001. Significant increases in the megawatt capacity of generation assets in operation were more than offset by decreases in the average price realized for electricity generated, resulting in a reduction in operating revenue of $415 million. In addition, revenues decreased $1,017 million as a result of a decrease in the trading and marketing net margin. DENA s results reflected the negative impacts of a prolonged economic weakness, low commodity prices, continued low volatility levels (measures of the fluctuation in the prices of energy commodities or products), reduced spark spreads, and decreased market liquidity.

Operating Expenses and Impairments. Operating expenses for 2002 decreased $261 million, compared to 2001. The decrease was driven primarily by:

Lower incentive compensation expense of $300 million, primarily related to trading activities

Decreased bad debt expense of $123 million

Lower fuel costs of $88 million

Demolition reserves recorded in 2001 of $65 million

Asset impairment and other charges of $229 million related to market conditions in 2002 and strategic actions taken by management, as described above

Higher depreciation expense of $89 million, related to the commencement of operations of nine generation facilities by mid-year 2002

Severance costs of $19 million in 2002 associated with work force reductions

Gains on Sales of Other Assets, net. Gains on sales of other assets of $229 million in 2001 resulted from the sale of interests in several generating facilities.

Other Income, net of expenses. Other income, net of expenses, increased $25 million in 2002 compared to 2001. The increase was due primarily to 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.

Minority Interest (Benefit) Expense. Minority interest benefit increased $87 million for 2002 compared to 2001, due to increased losses at DETM.

EBIT. EBIT for 2002 decreased $1,318 million compared to 2001. The decrease was due primarily to those factors discussed above: decreased trading margins, a decrease in the average price realized on electric generation, a decrease in the number of generation facilities sold in 2002, and certain charges taken as a result of market conditions in 2002 and strategic actions taken by management.

As a result of Duke Energy s findings in the course of its investigation related to the SEC inquiry on round trip trades (see Note 17 to the Consolidated Financial Statements), DENA identified accounting issues that justified adjustments which reduced its EBIT by $11 million during 2002. An additional $2 million charge was recorded in other Duke Energy business segments related to these findings.

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International Energy

	Years Ended December 31,		
	2003	2002	2001
	(in millions, except where noted)		
Operating revenues	$ 597	$ 743	$ 684
Operating expenses	406	716	458
Gains on sales of other assets, net			9
Operating income	191	27	235
Other income, net of expenses	32	85	24
Minority interest expense	13	10	23
EBIT	$ 210	$ 102	$ 236
Sales, GWh	16,374	18,350	15,749
Proportional megawatt capacity in operation	4,121	3,917	3,968

Year Ended December 31, 2003 as Compared to December 31, 2002

Operating Revenues. Operating revenues for 2003 decreased $146 million, compared to 2002. The decrease was driven primarily by:

A $91 million increase in 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. The change related to prices was not material.

Lower revenues of $35 million in El Salvador as a result of a power sales contract not being renewed by a counterparty

Lower liquefied natural gas sales of $33 million, due primarily to the termination of a gas sales contract

Currency translation impacts resulting in a decrease of $10 million in Brazil and Argentina

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 megawatt (MW) expansion in Guatemala

Increases to revenues and receivables for adjustments of $11 million as a result of a regulatory audit in Brazil

Operating Expenses. Operating expenses for 2003 decreased $310 million compared to 2002. The decrease was driven primarily by:

A $91 million increase in 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

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Lower expenses in the liquefied natural gas business due to a $40 million reduction in 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

Higher operating expenses of $22 million due to the completion of the 160 MW expansion in Guatemala

Other Income, net of expenses. Other income, net of expenses decreased $53 million compared to 2002. 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

A $26 million charge and reserve for environmental settlements in Brazil

An $11 million increase in equity investment income at National Methanol Company due to favorable product prices

EBIT. EBIT for 2003 increased $108 million, compared to 2002. This increase was due primarily to the absence of $75 million in 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 liquefied natural gas 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.

Matters Impacting Future International Energy s Results

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 Latin America (primarily Brazil), optimizing the output and efficiency of its various facilities, controlling and reducing costs and actively managing its portfolio of assets. International Energy estimates 2% to 3% compounded annual EBIT growth over the next three years.

If estimated cash flows over the lives of International 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. 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 impact an impairment analysis. As of December 31, 2003, International Energy had $238 million in goodwill, $1,752 million in net property, plant and equipment, and $1,625 million in assets held for sale.

EBIT results for International Energy are sensitive to short term translation impacts from fluctuations in exchange rates, most notably, the Brazilian Real and the Mexican Peso. Results could also be affected by significant changes in the Argentine Peso, the Peruvian Nuevo Sol, and the Bolivian Boliviano.

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. Following the 2002 devaluation of the Brazilian currency, 2003 inflation rates were significantly higher than in recent years impacting both revenue and interest expense. Current inflation levels are lower than they were on average for 2003.

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Regulatory changes in Brazil affecting the electric sector have been passed by the Brazil legislature. Implementation of the regulations are still being developed by the regulatory authority but could significantly affect the ability of International Energy s existing Brazilian plants to receive competitive market prices for their energy capacity and production.

Year Ended December 31, 2002 as Compared to December 31, 2001

Operating Revenues. Operating revenues for 2002 increased $59 million, compared to 2001. The increase was driven primarily by:

A $91 million increase in 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 $36 million increase due to the effect of reporting a full year of operations in 2002 for assets acquired in Guatemala during 2001, compared to only two months in 2001

A $15 million increase in Peru due primarily to higher electricity sales volumes

A $70 million decrease from currency translations within Brazil and Argentina

A $15 million decrease as a result of lower sales volumes and commodity prices at International Energy s liquefied natural gas business

Operating Expenses. Operating expenses for 2002 increased $258 million, compared to 2001. The increase was driven primarily by:

A $91 million increase in 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 impairment charge in 2002 related to the write-off of project and site development costs in Brazil and Bolivia

A $28 million increase in operating expenses related to the effect of reporting a full year of operations in 2002 for assets acquired in Guatemala during 2001, compared to only two months in 2001

A $22 million increase in the liquefied natural gas business reserve for estimated probable losses due to the early termination of a natural gas sales contract

A $19 million increase in Brazil as a result of reserve reversals in 2001 and the establishment of settlement provisions in 2002

Other Income, net of expenses. Other income, net of expenses increased $61 million in 2002, compared to 2001. The increase was primarily the result of $48 million of income generated from certain assets in Mexico acquired with the Westcoast acquisition in March 2002, as well as a $9 million increase in the equity investment income from operations in Peru.

EBIT. EBIT for 2002 decreased $134 million, compared to 2001. This decrease was due primarily to charges recorded as a result of the write-off of site development costs and the write-down of uninstalled turbines, primarily related to planned energy plants in Brazil and Bolivia. This decrease was partially offset by the positive effect of the Guatemala acquisition.

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Crescent

	Years Ended December 31,		
	2003	2002	2001
		(in millions)	
Operating revenues	$ 284	$ 226	$ 213
Operating expenses	232	177	151
Gains on sales of investments in commercial and multi-family real estate	84	106	106
Operating income	136	155	168
Other income, net of expenses		1	1
Minority interest expense (benefit)	3	(2)	2
EBIT	$ 133	$ 158	$ 167

Year Ended December 31, 2003 as Compared to December 31, 2002

Operating Revenues. Operating revenues for 2003 increased $58 million, compared to 2002. 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 in a new development in 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. Operating expenses for 2003 increased $55 million, compared to 2002. 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. 2003 Gains on sales of Investments in Commercial and Multi-family Real Estate decreased $22 million compared to 2002 primarily 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 is 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 is due to the initial sales of land at our Potomac Yard project in the Washington, DC area.

EBIT. For 2003, EBIT decreased $25 million, compared to 2002, due primarily to decreased land management sales partially offset by earnings from commercial land sales and increased residential developed lot sales.

Matters Impacting Future Crescent s Results

Crescent plans sustained levels of earnings in its development activities, while generating additional cash flow through increased sales of developed and undeveloped land. Crescent estimates 0%-2% compounded annual earnings growth over the next three years.

Year Ended December 31, 2002 as Compared to December 31, 2001

Operating Revenues. Operating revenues for 2002 increased $13 million, compared to 2001. The increase was driven primarily by a $29 million increase in Crescent s residential developed lot sales in 2002, due to the addition of several high-end communities offset by a $19 million reduction in commercial rental revenue due to soft market conditions and a smaller portfolio of commercial properties due to large portfolio sales in 2001.

Operating Expenses. Operating expenses for 2002 increased $26 million, compared to 2001. The increase was driven by a $28 million increase in the cost of developed lot sales resulting from an increase in sales as discussed above.

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Gains on Sales of Investments in Commercial and Multi-Family Real Estate. The 2002 gains on sales of investments in commercial and multi-family real estate remained flat over 2001. However, commercial project sales decreased $30 million due to a reduced inventory of commercial buildings available for sale resulting from large portfolio sales in 2001. Offsetting this decrease was a $29 million increase in legacy land sales in 2002, resulting from opportunities to accelerate sales of large, contiguous tracts in North and South Carolina.

Other

	Years Ended December 31,		
	2003	**2002**	**2001**
		(in millions)	
Operating revenues	$ 1,628	$ 303	$ 597
Operating expenses	1,933	655	1,113
Gains on sales of other assets, net		32	
Operating loss	(305)	(320)	(516)
Other income (loss), net of expenses	33	(48)	(23)
EBIT	$ (272)	$ (368)	$ (539)

Year Ended December 31, 2003 as Compared to December 31, 2002

Operating Revenues. Operating revenues for 2003 increased $1,325 million, compared to 2002. The increase was driven primarily by:

A $1,300 million increase at Duke Energy Merchants, LLC (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 Energy Delivery Services (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 $172 million decrease due to the sale of Duke Engineering & Services, Inc. (DE&S) and DukeSolutions, Inc. (DukeSolutions) in 2002

Operating Expenses. Operating expenses for 2003 increased $1,278 million, compared to 2002. 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, as described earlier

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

A $164 million decrease due to the sale of DE&S and DukeSolutions in 2002

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 for 2003 decreased $32 million, 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 $81 million for 2003, compared to 2002, due primarily to increased earnings related to Duke/Fluor Daniel (D/FD).

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EBIT. For 2003, EBIT increased $96 million, compared to 2002. As discussed above, the increase in EBIT was primarily driven by the increase in other income, offset by the decrease due to the sale of assets.

Matters Impacting Future Other Results

In 2003, a significant portion of Other was either sold or classified as held-for-sale. For 2004, Other will be comprised mainly of DEM, DukeNet Communications, LLC (DukeNet), D/FD and certain unallocated corporate costs. DEM is still winding down its positions in ammonia, coal, hydrocarbon, and refined products. Earnings from DukeNet should remain relatively stable, while earnings from D/FD will continue to decrease as the partnership winds down.

Year Ended December 31, 2002 as Compared to December 31, 2001

Operating Revenues. Operating revenues for 2002 decreased $294 million, compared to 2001. The decrease was driven primarily by:

A $339 million decrease due primarily to the sale of DE&S and DukeSolutions in 2002, resulting in a partial year of revenues compared to a full year in 2001

A $142 million decrease due to revenues in 2001 on corporately managed energy risk positions used to hedge exposure to commodity prices

A $92 million increase in revenues from EDS, which was formed in the second quarter of 2002

A $39 million increase at DEM as a result of increased trading and marketing net margins in 2002, and the write-offs for Enron Corporation (Enron) and Agrifos in 2001

Operating Expenses. Operating expenses for 2002 decreased $458 million, compared to 2001. The decrease was driven primarily by:

A $364 million decrease due primarily to sale of DE&S and DukeSolutions in 2002, resulting in a partial year of expenses

A $134 million decrease due to expenses in 2001 on corporately managed energy risk positions used to hedge exposure to commodity prices

A $52 million decrease due to expenses associated with increased contributions in 2001 to the Duke Energy Foundation (an independent, Internal Revenue Code section 501(c)(3) entity that funds Duke Energy s charitable contributions)

A $77 million increase in operating expenses as a result of the formation of EDS in the second quarter of 2002

A $17 million increase for severance charges in 2002 at D/FD due to the downturn in the domestic power industry.

Gains on Sales of Other Assets, net. Gains on sales of other assets for 2002 was comprised primarily of a $33 million net gain on the sale of Duke Energy s remaining water operations.

Other Income, net of expenses. Other income, net of expenses decreased $25 million due primarily to decreased equity earnings from D/FD.

EBIT. EBIT for 2002 increased $171 million, compared to 2001. The increase was due primarily to gains on sales of other assets, as described above, earnings generated from EDS and the DEM write-off for Enron and Agrifos in 2001.

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Other Impacts on Earnings Available for Common Stockholders

Interest expense increased $283 million in 2003 as compared to 2002. The increase was due primarily to a $136 million decrease in capitalized interest, resulting primarily from DENA s significantly lower plant construction activity in 2003, and expenses of $48 million related to certain 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. Interest expense also increased $16 million as a result of a 2003 regulatory action by the PSCSC which required the write-off of a portion of regulatory assets related to debt issuance costs (see Note 4 to the Consolidated Financial Statements). The 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.

In 2002 as compared to 2001, interest expense increased $337 million, due primarily to higher debt balances resulting from debt assumed in, and issued with respect to, the acquisition of Westcoast and increased financing throughout the corporation, partially offset by lower interest rates in 2002.

Minority interest expense decreased $55 million in 2003 as compared to 2002, and decreased $210 million in 2002 as compared to 2001. 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, and due to lower distributions related to Catawba River Associates, LLC (changes in its ownership structure as of October 2002 caused costs associated with this financing to be classified as interest expense from minority interest), minority interest expense decreased $75 million for 2003 and $31 million for 2002.

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 $20 million in 2003 as compared to 2002, and decreased $179 million in 2002 as compared to 2001. The 2003 change was driven by increased earnings at DEFS, and Natural Gas Transmission, offset by decreased earnings at DETM. The 2002 change was driven by decreased earnings at DETM and decreased earnings from DEFS.

Income tax expense decreased $1,320 million for the year ending December 31, 2003, compared to the same period in 2002, due primarily to the large write-offs in 2003. Income tax expense decreased $538 million in 2002, compared to 2001, due primarily to a $1,241 decrease in earnings from continuing operations before income taxes, favorable foreign taxes due to the acquisition of regulated Westcoast entities, a benefit from a change in the federal tax law relating to the deduction of employee stock ownership plan dividends, and a state tax settlement finalized during 2002.

Loss from discontinued operations was $152 million for 2003, $262 million for 2002 and $5 million for 2001. These amounts represent operating losses and net loss on dispositions related primarily to International Energy s Australian and European operations, Duke Capital Partners, LLC (DCP) and certain businesses at DEFS and DEM. (See Note 12 to the Consolidated Financial Statements.) 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 Australian assets as held for sale and to exit the European market. The 2002 amount is primarily comprised of $194 million charge for the impairment of goodwill for International Energy s European trading and marketing 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

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share, related to the implementation of EITF Issue No. 02-03 and an after-tax charge of $11 million, or $0.01 per basic share, due to the implementation of SFAS No. 143, Accounting for Asset Retirement Obligations. (See Note 1 to the Consolidated Financial Statements.)

During 2001, Duke Energy recorded a one-time net-of-tax charge of $96 million related to the cumulative effect of a change in accounting principle for the January 1, 2001 adoption of SFAS No. 133. This charge related to contracts that either did not meet the definition of a derivative under previous accounting guidance or do not qualify as hedge positions under new accounting requirements. (See Notes 1 and 8 to the Consolidated Financial Statements.)

CRITICAL ACCOUNTING POLICIES

The selection and application of accounting policies 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 that require the use of significant estimates and judgments and have a material impact on its consolidated financial position and results of operations. 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 other significant accounting policies with senior members of management and the audit committee, as appropriate. Duke Energy s critical accounting policies are listed below.

Risk Management Activities

Duke Energy uses two comprehensive accounting models for its risk management activities in reporting its consolidated financial position and results of operations as required by GAAP: a fair value model and an accrual model. For the three years ended December 31, 2003, 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 presentation of the accounting used for certain of Duke Energy s transactions, the overall application of the models remains the same.

The fair value model incorporates the use of mark-to-market (MTM) accounting. Under this method, 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 Non-regulated Electric, Natural Gas, Natural Gas Liquids and Other in the Consolidated Statements of Operations during the current period. While DENA is the primary business segment that uses this accounting model, International Energy, Field Services, Other and Franchised Electric also have certain transactions subject to this model. For the year ended December 31, 2003, Duke Energy applied MTM accounting to its derivative contracts, unless subject to hedge accounting or the normal purchase and normal sale exemption (as described below). For the years ended December 31, 2002 and 2001, Duke Energy also applied MTM accounting to energy trading contracts, as defined by EITF Issue No 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities.

MTM accounting 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 energy trading 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

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significant component affecting the ultimate fair value for a contract subject to mark-to-market accounting after implementation of EITF 02-03 due to the discontinuation of mark-to-market accounting 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.

Validation of a contract s calculated fair value is performed by the Risk Management Group. 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.

Often for a derivative instrument that is initially subject to MTM accounting, Duke Energy applies either hedge accounting or the normal purchase and normal sales exemption in accordance with SFAS No. 133. 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 only limited recognition related to hedge ineffectiveness 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 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 realized 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 method. The unrealized loss associated with power forward sales contracts designated under the normal purchases and normal sales exemption as of December 31, 2003 was approximately $700 million. This unrealized loss represents the difference in the normal purchases and normal sales contract prices compared to the forward market prices of power as of December 31, 2003 and is partially offset by unrealized gains on natural gas positions of approximately $400 million which are recorded on the Consolidated

Balance Sheet in Unrealized Gains and Losses on Mark-to-Market and Hedging Transactions. Duke Energy intends to fulfill these contractual obligations with production from its power generation fleet and, assuming that occurs, the above unrealized gains and losses would not be recognized in DENA s EBIT.

Regulatory Accounting

Duke Energy accounts for 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 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. This determination 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 $2,016 million as of December 31, 2003 and $1,421 million as of December 31, 2002. (See Note 4 to the Consolidated Financial Statements.)

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 exists 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 natural gas liquids and costs of fuel over periods of time consistent with the useful lives of the assets. 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.

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Judgment is also involved in determining the timing of meeting the criteria for classification as an asset held for sale under SFAS No. 144.

Duke Energy intends to dispose of certain other assets in addition to the assets classified as held for sale at December 31, 2003. Negotiations for dispositions of these other assets, in addition to those classified as held for sale, are at various stages with prospective buyers. Based on current market conditions in the merchant energy industry, it is reasonably possible that Duke Energy s estimate of fair value of the long-lived assets impaired in 2003 could change and the change would impact the consolidated results of operations.

Impairment of Goodwill

Duke Energy evaluates the impairment of goodwill under SFAS No. 142. The majority of Duke Energy s goodwill relates to the acquisition of Westcoast in March 2002 and was not impaired as of December 31, 2003. The remainder relates to Field Services and International Energy s Latin America operations. 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. As a result of the 2003 impairment test, Duke Energy recorded a $254 million goodwill impairment charge in the third quarter 2003 to write off all DENA goodwill, most of which related to certain aspects of DENA s trading and marketing business. This impairment charge reflects 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 perform the assessment. 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 as well as historical factors and fundamental analysis as well as other factors into its forecasted commodity prices.

As the challenging market conditions continue into 2004, in addition to performing the annual goodwill impairment analysis required by SFAS No. 142, management will remain alert for any indicators that the fair value of a reporting unit could be below book value and 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 kilowatt hour 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.

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 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.

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Trading and Marketing Revenues. The recognition of income in the Consolidated Statements of Operations for derivative activity is primarily dependent on whether the accrual method or mark-to-market method of accounting is applied. Prior to January 1, 2003, Duke Energy applied the mark-to-market accounting method 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, the use of mark-to-market accounting 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 method of accounting. While the mark-to-market method of accounting is the default method of accounting for all SFAS No. 133 derivatives, SFAS No. 133 allows for the use of accrual accounting 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 or mark-to-market method of accounting, see Risk Management Activities 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.

Pension

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.

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.

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. For Duke Energy s U. S. defined benefit pension plans, it recognized expense of $2 million in 2003 and income of $27 million and $9 million in 2002 and 2001, respectively. Duke Energy expects its U.S. pension income to be less than $1 million in 2004. The Westcoast retirement plans recognized pension expense of $13 million in 2003 and $4 million in 2002 and has expected pension expense of $14 million in 2004.

The fair value of Duke Energy s U.S. plan assets increased to $2,477 million as of September 30, 2003 from $2,120 million as of September 30, 2002. Higher 2003 investment returns, net of ongoing benefit payments and declining interest rates have decreased Duke Energy s plan s calculated under-funded status to $286 million as of September 30, 2003 from $551 million as of September 30, 2002. Funding requirements for defined benefit plans are determined by government regulations, not SFAS No. 87. Duke Energy made a voluntary contribution of $181 million to its U.S. defined benefit retirement plan in 2003. No contributions to the Duke Energy plan were necessary in 2002 or 2001. No decision on 2004 contributions has been reached due to significant uncertainty around pending U.S. Congressional action over required interest rates used to determine minimum funding requirements. Duke Energy made contributions to the Westcoast pension plans of approximately $11 million in 2003 and $9 million dollars in 2002. Duke Energy anticipates that it will make contributions of approximately $27 million to the Westcoast plans in 2004.

The calculation of pension expense and Duke Energy s pension liability requires 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 two most critical assumptions are the expected long-term rate of return on plan assets and the assumed discount rate.

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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, 2003 and 2002, and 9.25% as of September 30, 2001. The assets for Duke Energy s U.S. pension plan 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 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 4.18% for U.S. equities, 1.92 % for Non U.S. equities, 2.21 % for fixed income securities, and 0.24% for real estate. A premium of 0.36% 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 2003, pre-tax pension expense would have been higher by approximately $16 million.

The long-term rate of return for the Westcoast plan assets was 7.5% as of September 30, 2003 and 7.75% in 2002. The Westcoast plan 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 long-term rate of return of 7.5% 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 3.15% for Canadian equities, 1.27% for U.S. equities, 1.41% for Europe, Australasia and Far East equities, and 1.79% for fixed income securities. If the Westcoast plan had used a long-term rate of 7.00% in 2003, pre-tax pension expense would have been higher by less than $2 million.

Duke Energy discounted its future U.S. pension obligations using a rate of 6.0% as of September 30, 2003, compared to 6.75% as of September 30, 2002 and 7.25% as of September 30, 2001. 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. For 2003, the discount rate used to calculate pension expense was 6.75%. Lowering the discount rate by 0.25% (from 6.75% to 6.5%) would have decreased Duke Energy s 2003 pension expense by approximately $5 million, before income taxes.

Westcoast discounted its future pension obligations using a rate of 6.0% as of September 30, 2003, compared to 6.5% as of September 30, 2002. 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. For 2003, the discount rate used to calculate pension expense was 6.5%. Lowering the discount rate by 0.25% (from 6.5% to 6.25%) would have increased Duke Energy s 2003 pension expense by less $2 million, before income taxes.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in Duke Energy s pension plans will impact Duke Energy s future pension expense and liabilities. Management cannot predict with certainty what these factors will be in the future.

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LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

Duke Energy relies primarily upon cash flows from operations, as well as borrowings and the sale of assets to fund its liquidity and capital requirements. 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 comprise a substantial portion of Duke Energy s cash flow from operations and it is anticipated to continue as such for the next several years.

Duke Energy currently anticipates net cash provided by operating activities in 2004 to be approximately $4.0 billion. In addition to net cash provided by operating activities, Duke Energy also expects to generate approximately $2.2 billion of proceeds from asset sales in 2004, including approximately $900 million of debt that is intended to be transferred in connection with the Australian sales transaction and subsequently retired. Achievement of these projected amounts is subject to a number of factors, including, but not limited to, regulatory constraints, economic trends, divestiture opportunities and market volatility. The 2004 asset sales principally include International Energy s Australian operations, including its related debt, and DENA s Southeast merchant generation plants. Management anticipates either an initial public offering or the sale of the Australian operations by mid-2004, and the sale of merchant generation plants by the end of 2004.

Duke Energy s projected 2004 capital and investment expenditures are approximately $2.5 billion. Duke Energy is focusing on reducing risk and restructuring its business for future success, including opportunities to reduce further projected capital and investment expenditures. Duke Energy will invest in its strongest business sectors with an overall focus on positive net cash generation. Based on this goal, approximately 65% of total projected 2004 capital expenditures are projected to be allocated to Natural Gas Transmission and Franchised Electric. Total projected capital and investment expenditures include approximately $1.5 billion for maintenance and upgrades of existing plants, pipelines, and infrastructure to serve load growth. Additionally, Duke Energy has approximately $0.3 billion in capital and investment expenditures designated for Crescent, including amounts for residential real estate. Expenditures at Crescent and Natural Gas Transmission constitute the majority of the expansion capital planned in 2004 by Duke Energy.

In 2004, Duke Energy expects to continue to pay down overall debt by approximately $3.5 billion to $4.0 billion, which includes approximately $900 million for Australian dollar denominated debt that is intended to be transferred in connection with the sale transaction and subsequently retired, through the settlement of the forward stock purchase component of the outstanding Equity Units in May and November 2004 totaling $1,625 million, asset sales, and cash from operations. The reductions in debt are expected to consist of debt maturities, the early retirement of all economically callable debt, and other reductions. Additionally, Duke Energy expects to obtain some funding through common stock issuances in its InvestorDirect Choice Plan (a stock purchase and dividend reinvestment plan) and employee benefits.

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 will 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 as evidenced by the Stable Outlook ratings of the agencies that are retained to rate Duke Energy and its subsidiaries.

Operating Cash Flows

Net cash provided by operating activities was $3,419 million in 2003 compared to $4,199 million in 2002, a decrease of $780 million. The decrease in cash provided by operating activities was due primarily to lower cash settlements from trading and hedging activities, and less cash flows in 2003 from changes in working capital, principally accounts payables and accounts receivable. Additionally, in 2003, Duke Energy made a voluntary contribution of $181 million to its U.S. defined benefit pension plan. No contributions to the Duke Energy defined pension plan were made in 2002 or 2001. No decision for the U.S. plan on 2004 contributions has been reached due to significant uncertainty around pending U.S. Congressional action over required interest rates used to determine minimum funding requirements. Also, Duke Energy made contributions to the Westcoast retirement plans (Westcoast plans) of approximately $11 million in 2003 and $9 million in 2002. Duke Energy anticipates that it will make contributions of approximately $27 million to the Westcoast plans in 2004.

Net cash provided by operating activities was $4,199 million in 2002 compared to $3,749 million in 2001, an increase of $450 million. The increase in cash provided by operating activities was due primarily to higher cash earnings plus changes in working capital from 2001. Although net income significantly decreased in 2002 (see Results of Operation for further discussion) many of the items affecting net income were non-cash. Non-cash items affecting earnings included an increase in depreciation expense, primarily due to the acquisition of Westcoast; non-cash impairment charges for goodwill (at International Energy), project sites (primarily at DENA) and property plant and equipment; and higher deferred tax expense.

Investing Cash Flows

Cash used in investing activities was $421 million in 2003 compared to $6,461 million in 2002, a decrease of $6,040 million. Additionally, cash used in investing activities was $6,461 million in 2002 compared to $5,435 million in 2001, an increase of $1,026 million. The primary use of cash related to investing activities is capital and investment expenditures, which are detailed by business segment in the following table.

Capital and Investment Expenditures by Business Segment(a)

	Years Ended December 31,		
	2003	**2002**	**2001**
		(in millions)	
Franchised Electric	$ 1,030	$ 1,269	$ 1,115
Natural Gas Transmission	766	2,878	748
Field Services	211	309	587
Duke Energy North America	277	2,013	3,213
International Energy	71	412	442
Crescent(c)	290	275	452
Other(b)	116	193	483
Cash acquired in acquisitions		(77)	(17)
Total consolidated	$ 2,761	$ 7,272	$ 7,023

(a) Amounts include the acquisition of Westcoast in 2002

(b) Amounts include deferral in the consolidation of fifty percent of the profit earned by D/FD for the construction of DENA s merchant generation plants, which is associated with Duke Energy s ownership.

(c) Amounts include capital expenditures for residential real estate included in operating cash flows of $196 million in 2003, $179 million in 2002 and $230 million in 2001.

Capital and investment expenditures, including Crescent residential real estate investments, decreased $4,511 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 are due to deferred construction on the Moapa, Grays Harbor, and Luna facilities of $621 million, decreases in expenditures for the Marshall, Sandersville, and Moss Landing facilities of $380 million, and a decrease in turbine purchases of

$434 million. Capital and investment expenditures also decreased in 2003 due to a decrease in plant construction costs at Franchised Electric primarily due to a decrease of approximately $250 million in expenditures related to environmental equipment at its coal-fired plants and the Mill Creek combustion turbine plant, which was completed in 2003; a decrease in plant construction costs at International Energy of $268 million, primarily in Australia; a decrease in investments in Natural Gas Transmission s 50% interest in Gulfstream of $226 million; and a reduction in investments at Other (primarily related to DCP).

The decrease in investing cash flow in 2003 when compared to 2002 was also impacted by the 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 Pipelines L.P.; Field Services sale of assets to Crosstex Energy Services, L.P. & ScissorTail Energy, LLC, and Duke Energy s sale of the 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, sale of its European gas marketing business, and sale of its French generating facility; and the monetization of various investments at DCP.

Capital and investment expenditures increased $249 million in 2002 compared to 2001. The increase was due primarily to cash used in the acquisition of Westcoast of $1,707 million, net of cash acquired, partially offset by decreases in capital expenditures and investment expenditures. Capital expenditures decreased when compared to 2001 due to a decrease in DENA investments in generating facilities of approximately $1,030 million, as a result of management s revised outlook for the merchant energy portion of its business, and a decrease in acquisitions of businesses and assets of approximately $375 million when compared to 2001. These decreases in capital expenditures were partially offset by an increase in plant construction costs at Franchised Electric of approximately $185 million primarily due to expenditures at the Mill Creek combustion turbine plant and related to environmental equipment at coal-fired plants; and an increase in investments in property plant and equipment of approximately $520 million at Natural Gas Transmission due primarily to increased expansion and maintenance projects related to the Westcoast, Algonquin Gas Transmission Company, East Tennessee Natural Gas Company, and Texas Eastern Transmission LP (Texas Eastern) systems, along with the Maritimes & Northeast Pipeline (M&N Pipeline) expansion costs after its consolidation in 2002. Investment activities also decreased when compared to 2001, due primarily to reduced investments at Other (primarily related to a decrease of approximately $110 million in notes receivable at DCP) and a decrease of approximately $205 million in expenditures for Natural Gas Transmission s investment in Gulfstream. The remaining decrease of approximately $440 million is associated with a decrease in capital and investment expenditures throughout Duke Energy s segments.

In June 2002, the state of North Carolina passed new clean air legislation that includes provisions that freeze 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 recording of compliance costs. During the rate freeze period, Duke Energy is expected to recover a minimum of 70% of the total estimated costs of compliance. (See Note 17 to the Consolidated Financial Statements.) As part of this legislation Duke Energy will spend an estimated total of $1.5 billion over the next ten years to install pollution controls in its coal-fired plants. Duke Energy expects to incur approximately $80 million of total capital costs associated with this legislation in 2004.

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

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Financing Cash Flows and Liquidity

Duke Energy s consolidated capital structure as of December 31, 2003, including short-term debt, was 58% debt, 37% common equity and 5% minority interests. Fixed charges coverage ratio, calculated using SEC guidelines, was 2.2 times for 2002 and 3.9 times for 2001. Earnings were inadequate to cover fixed charges by $1,715 million for the year ended December 31, 2003 as a result of approximately $3.5 billion in non-cash impairment charges incurred in 2003.

Cash flows from financing activities decreased $5,503 million to net cash used in financing activities of $2,657 million 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. This 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.

Cash flows provided by financing activities were $2,846 million in 2002 and $1,354 million in 2001, an increase of $1,492 million. This change was due primarily to the net increase in outstanding long-term debt as a result of the 2002 Westcoast acquisition.

During 2003, cash from operations and the sale of assets was adequate for funding Duke Energy s cash requirements such as capital expenditures, dividend payments and permanently retiring a portion of scheduled debt maturities.

Significant Financing Activities. During 2003, Duke Energy issued $500 million of 3.75% first and refunding mortgage bonds due in 2008 in a private placement transaction exempt from registration under Rule 144A of the Securities Act of 1933, as amended (Securities Act). Pursuant to a registration agreement, Duke Energy registered an exchange with the holders of identical bonds under the Securities Act on a registration statement filed with the SEC. This registration statement was declared effective and the exchange offer was completed during the third quarter of 2003 with substantially all of the private bonds exchanged for registered bonds. There were no proceeds to Duke Energy from the exchange. The proceeds of the offering of the private bonds were used to repay short-term debt, to replace $100 million of Duke Energy s first and refunding mortgage bonds that matured in February 2003, to repay approximately $200 million of an intercompany loan from Duke Capital and for general corporate purposes.

Also in 2003, Duke Energy completed a $700 million offering of 1.75% convertible senior notes due in 2023. In connection with the offering, the underwriters exercised an option to purchase an additional $70 million of convertible senior notes to cover any over allotments. Each of these senior notes is 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 holders put the senior notes back to Duke Energy, 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, 2003. 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. The net proceeds of the offering were used for general corporate purposes, including the reduction of outstanding commercial paper.

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 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, 2003, the interest rate associated with the credit facility, which is based on commercial paper rates, was 1.5% 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, 2003, the $300 million outstanding balance of the credit facility was secured by approximately $446 million of accounts receivable held by DERF. The obligations of DERF under the credit facility are non-recourse to Duke Energy.

Additionally, during 2003, Duke Energy issued $200 million of 4.50% first and refunding mortgage bonds due in 2010, and $500 million of 5.30% first and refunding mortgage bonds due in 2015. The proceeds from the first mortgage bond issuances were used for general corporate purposes, to repay commercial paper, and to redeem (1) at 102% of their aggregate principal amount, $200 million of 6.875% first and refunding mortgage bonds due in 2023, (2) at 101.785% of their aggregate principal amount, $150 million of 6.75% first and refunding mortgage bonds due in 2025 and (3) at 102.35% of their aggregate principal amount, $150 million of 7.0% first and refunding mortgage bonds due in 2033. The loss of approximately $23 million from the redemption of the first and refunding mortgage bonds will be deferred over the life of the 5.30% first and refunding mortgage bond issuance. Duke Energy also issued $300 million of 4.20% senior unsecured notes due in 2008, and $250 million of senior unsecured floating rate notes (based on the three-month LIBOR plus 0.45%) due in 2005. The net proceeds from the note issuances were used for general corporate purposes, including the repayment of commercial paper.

During 2003, PanEnergy Corp (PanEnergy), a wholly owned subsidiary of Duke Energy, called $328 million of 7.75% bonds due in 2022. The bonds were redeemed at 102% of their aggregate principal amount. The pre-tax loss of approximately $13 million on the early extinguishment of the debt was recorded as Interest Expense in the Consolidated Statements of Operations.

In June 2003, prior to the implementation of SFAS No. 150, Duke Capital redeemed $250 million of its 7.375% trust preferred securities due in 2038. The redemption price for this issuance was approximately $250 million, and an approximate loss of $8 million on the early extinguishment of the trust preferred securities was recorded as Dividends and Premiums on Redemption of Preferred and Preference Stock in the Consolidated Statements of Operations. In December 2003, subsequent to the implementation of SFAS No. 150, Duke Capital redeemed $350 million of its 7.375% trust preferred securities due in 2038. The redemption price for this issuance was approximately $350 million, and an approximate loss of $10 million on the early extinguishment of the trust preferred securities was recorded as Interest Expense in the Consolidated Statements of Operations.

During 2003, $1,000 million of commercial paper that had been included in Long-term Debt on the December 31, 2002 Consolidated Balance Sheet was reclassified as Notes Payable and Commercial Paper. This reclassification reflects Duke Energy s intention to no longer maintain a significant outstanding long-term portion of commercial paper. As of December 31, 2003, $150 million of commercial paper was included in Long-term Debt.

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Also, in 2003, as a result of International Energy s Australian operations being classified as discontinued operations, $883 million of debt related to those operations was reclassified from Notes Payable and Commercial Paper and Long-term Debt to Current and Non-Current Liabilities Associated with Assets Held for Sale on the December 31, 2003 Consolidated Balance Sheet. For additional information about discontinued operations see Note 12 to the Consolidated Financial Statements.

In February 2004, Duke Capital remarketed $875 million of its 5.87% senior notes due in 2006. As a result of the remarketing, the interest rate on the notes was reset to 4.302%. The remarketing was required under the terms of the Equity Units originally issued by Duke Energy in March 2001. Proceeds from the remarketed senior notes were used to purchase U.S. Treasury securities being held by a collateral agent to satisfy the forward stock purchase contracts component of the Equity Units. In May 2004, Duke Energy intends to receive $875 million from the collateral agent, and to issue approximately 22.5 million shares of Duke Energy common stock pursuant to the forward stock purchase contracts. Additionally, in February 2004, Duke Capital issued $200 million of 4.37% senior unsecured notes due in 2009 and $288 million of 5.50% senior unsecured notes due in 2014 in exchange for $475 million of the principal amount of the remarketed senior notes. After the exchange, $400 million of the principal amount of the remarketed senior notes remained outstanding.

Also, in February 2004, Duke Energy announced that on March 26, 2004, it will redeem the entire issue of 7.20% Duke Energy debt to an affiliate due in 2037. The redemption price will be approximately $360 million, and the redemption is not anticipated to have a material impact on Duke Energy s Consolidated Statements of Operations.

For additional information on subsequent debt issuances and redemptions see Subsequent Events section.

For additional information about Duke Energy s financing activities, and the impact of the 2003 adoption of SFAS No. 150 and FIN 46 (Revised December 2003) (FIN 46R), Consolidation of Variable Interest Entities An Interpretation of ARB No. 51, see Notes 14, 15 and 16 to the Consolidated Financial Statements.

Available Credit Facilities and Restrictive Debt Covenants. During 2003, Duke Energy, Duke Capital, Westcoast, Union Gas, DEFS and Duke Australia Finance Pty Ltd. (a wholly owned subsidiary of Duke Energy) replaced portions of their expiring credit facilities, thereby reducing the total amount of credit facilities available by approximately $2.2 billion. The majority of the credit facilities support commercial paper programs. 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 acceleration of due dates of certain borrowings and/or termination of the agreements. As of December 31, 2003, Duke Energy was in compliance with those covenants. In addition, certain of the agreements contain cross-acceleration provisions that may allow for acceleration of payments or termination of the agreements upon: (1) nonpayment or (2) acceleration of other significant indebtedness of the applicable borrower or certain of its subsidiaries. None of the credit agreements contain material adverse change clauses or any covenants based upon credit ratings.

For information on Duke Energy s credit facilities as of December 31, 2003, see Note 14 to the Consolidated Financial Statements.

Duke Energy has approximately $2,900 million of credit facilities which expire in 2004. It is Duke Energy s intent to resyndicate less than the total $2,900 million of expiring credit facilities.

Credit Ratings. In March 2003, Moody s Investors Service (Moody s) placed its long-term and short-term ratings of Duke Energy, Duke Capital and DEFS, and its long-term ratings of Texas Eastern and PanEnergy, on Review for Potential Downgrade. In June 2003, Moody s lowered its long-term rating of Duke Energy, its long-term and short-term ratings of Duke Capital, and its long-term ratings of Texas Eastern and PanEnergy one

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ratings level. Moody s actions were prompted by concerns regarding leverage ratios and cash flow coverage metrics at Duke Energy, and uncertainties associated with cash flow contributions from DENA and Duke Energy International, LLC. Moody s concluded its actions by placing Duke Energy, Duke Capital, Texas Eastern and PanEnergy on Stable Outlook. In September 2003, Moody s confirmed its long and short-term ratings of DEFS and placed DEFS on Stable Outlook, concluding its Review for Potential Downgrade.

In June 2003, S&P lowered its long-term ratings of Duke Energy, Duke Capital and its subsidiaries (with the exception of Maritimes & Northeast Pipeline, LLC and Maritimes & Northeast Pipeline, LP (collectively, M&N Pipeline) and DEFS) one ratings level. In addition, S&P lowered its Canadian commercial paper ratings of Westcoast and Union Gas one ratings level. S&P s actions were based on concern about Duke Energy s ability to strengthen its financial profile during the remainder of 2003 and in 2004, and its ability to absorb any further weakening in operating cash flows, while still meeting its debt reduction targets. S&P concluded its actions by leaving Duke Energy and its subsidiaries, excluding M&N Pipeline and DEFS, on Negative Outlook. In February 2004, S&P again lowered its long-term ratings of Duke Energy and its subsidiaries, with the exception 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 assets 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 all have a Stable Outlook, with the exception of DETM, which remained on Negative Outlook until July 9, 2004 when it was upgraded to stable.

The following table summarizes the March 1, 2004 credit ratings from the rating 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, 2004

	Standard and Poor s	**Moody s Investor Service**	**Dominion Bond Rating Service (DBRS)**
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(d)
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
(d) In August 2003, DBRS initiated a rating on Maritimes & Northeast Pipeline, LLC.

Duke Energy s credit ratings are dependent on, among other factors, the ability to generate sufficient cash to fund Duke Energy s capital and investment expenditures and dividends, while strengthening the balance sheet through debt reductions. If, as a result of market conditions or other factors affecting Duke Energy s business, Duke Energy is unable to execute its business plan or if its earnings outlook materially deteriorates, Duke Energy s ratings could be further affected.

Duke Energy and its subsidiaries are required to post collateral under certain trading and marketing and other contracts. Typically, the amount of the collateral is dependent upon Duke Energy s economic position at

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points in time during the life of a contract and the credit rating of the subsidiary obligated under the collateral agreement. Business activity by DENA generates the majority of Duke Energy s collateral requirements. DENA frequently transacts through DETM or Duke Energy Marketing America, a wholly owned subsidiary of Duke Capital.

A reduction in DETM s credit rating to below investment grade as of December 31, 2003 would have resulted in Duke Capital posting additional collateral of up to approximately $220 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, 2003, Duke Capital would have been required to escrow approximately $150 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, 2003 would have resulted in Duke Capital posting additional collateral of up to approximately $510 million. The amount of cash held as collateral that would have been required to be segregated into escrow due to a Duke Capital downgrade to below investment grade was less than $10 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 the termination of the agreements. As of December 31, 2003, Duke Capital could have been required to pay up to $100 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, 2003, Duke Energy had $19 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 $30 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, 2003, Duke Energy and its subsidiaries had effective SEC shelf registrations for up to $1,950 million in gross proceeds from debt and other securities. Subsequent to December 31, 2003, these SEC shelf registrations were reduced by $488 million as a result of the senior unsecured notes issued by Duke Capital in February 2004. Additionally, as of December 31, 2003, Duke Energy had access to 700 million Canadian dollars (U.S. $542 million) available under 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, 200 million Canadian dollars will expire in June 2004 and 500 million Canadian dollars will expire in November 2005.

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 77 consecutive years. Dividends on common and preferred stocks in 2004 are expected to be paid on March 16, June 16, September 16 and December 16, subject to the discretion of the Board of Directors.

Duke Energy s InvestorDirect Choice Plan allows investors to reinvest dividends in common stock and to purchase common stock directly from Duke Energy. Issuances under this plan were $111 million in 2003, $105 million in 2002 and $100 million in 2001.

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Duke Energy also sponsors employee savings plans that cover substantially all employees. Issuances of common stock under these plans were $156 million in 2003, $188 million in 2002 and $170 million in 2001. 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 $20 million for 2003, approximately $50 million for 2002 and approximately $60 million for 2001. This practice is expected to continue in 2004. (See Notes 20 and 21 to the Consolidated Financial Statements for additional information on stock-based compensation and employee benefit plans.)

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.

As discussed in Note 1 to the Consolidated Financial Statements, Summary of Significant Accounting Policies, Duke Energy has a variable interest in, but is not the primary beneficiary of, Duke COGEMA Stone & Webster, LLC (DCS) due to certain guarantee obligations as discussed in Note 18, Guarantees and Indemnifications. This guarantee obligation is an off-balance sheet arrangement. Duke Energy s maximum exposure to loss as a result of its variable interest in DCS cannot be quantified.

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 Notes 17 and 18 to the Consolidated Financial Statements.

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. The majority of current liabilities on the Consolidated Balance Sheets will be paid in cash in 2004.

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Contractual Obligations as of December 31, 2003

	Payments Due By Period				
	Total	Less than 1 year (2004)	2-3 Years (2005 & 2006)	4-5 Years (2007 & 2008)	More than 5 Years (Beyond 2008)
			(in millions)		
Long-term debt(a)	$ 34,922	$ 2,484	$ 7,460	$ 3,739	$ 21,239
Capital leases(a)	367	15	193	36	123
Operating leases(b)	508	98	127	76	207
Purchase Obligations:					
Firm capacity payments(c)	2,917	444	560	444	1,469
Energy commodity contracts(d)	10,571	5,221	3,531	958	861
Other purchase obligations(e)	4,561	1,120	1,264	376	1,801
Other long-term liabilities on the Consolidated Balance Sheets(f)	544	133	212	199	
Total contractual cash obligations	$ 54,390	$ 9,515	$ 13,347	$ 5,828	$ 25,700

(a) See Note 14 to the Consolidated Financial Statements. Amount also includes interest payments over life of debt.
(b) See Note 17 to the Consolidated Financial Statements.
(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 power, natural gas and NGLs. Amount includes certain normal purchases, energy derivates 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, 2003. For certain of these amounts, Duke Energy may net settle rather than paying cash. Amount excludes contracts to purchase commodities that do not require delivery of physical quantities and also are expected to net settle. The amounts presented for this line item have been revised from the originally presented total of $15, 923 million to adjust for amounts related to certain intercompany contracts that were included in the amount previously disclosed.
(e) Includes purchase commitments for coal, nuclear fuel supply contracts, 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 2004 (see Note 21 to the Consolidated Financial Statements), certain executive benefits, Department of Energy assessment fee (see Note 4 to the Consolidated Financial Statements), and asset retirement obligations which are contractually committed and contributions to the nuclear decommissioning trust fund (see Note 7 to the Consolidated Financial Statements). Duke Energy has not determined these amounts beyond 2008. The majority of asset retirement obligations is not yet contractually committed, and thus is 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) 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), funding of other post-employment benefits (see Note 21 to the Consolidated Financial Statements) and regulatory credits (see Note 4 to the Consolidated Financial Statements) 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 12 to the Consolidated Financial Statements) are also excluded as Duke Energy expects these liabilities will be assumed by the buyer upon sale of the assets.

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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 Executive Committee is responsible for the overall approval of market risk management policies and the delegation of approval and authorization levels. The Executive Committee is composed of senior executives who receive 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 Activities 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 Notes 1 and 8 to the Consolidated Financial Statements.)

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. In accordance with SFAS No. 133, Duke Energy s primary use of energy commodity derivatives is to hedge the output and production of assets it physically 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. 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 Notes 1 and 8 to the Consolidated Financial Statements.)

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. 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.

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 merchant plants in the Southeast U.S. and reduce DENA s interest in deferred plants required the reassessment of all associated derivatives, including normal purchases and normal sales. This required an accounting change from the accrual method of accounting to the mark-to-market method of accounting and introduced substantial unrealized losses not previously recognized in the Consolidated Financial Statements.

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Based upon the current net open positions for DENA s commodity derivatives recorded using the mark-to-market accounting method which includes the trading and undesignated portfolios, 2004 EBIT at DENA would change by approximately $25 million if forward power and natural gas prices were to increase or decrease over the entire position term in tandem by $1.00 per megawatt hour and $0.15 per million Btu s, respectively.

Based on a sensitivity analysis as of December 31, 2003, it was estimated that a difference of one cent per gallon in the average price of NGLs in 2004 would have a corresponding effect on operating income of approximately $6 million (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, 2002 estimated that operating income would have changed by approximately $7 million in 2003. The effect on operating income for 2004 or 2003 was also not expected to be material as of December 31, 2003 or 2002 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.

Trading. The risk in the trading 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 accounting method are shown in the following table.

Daily Earnings at Risk (in millions)

	Period Ending One-Day Impact on Operating Income for 2003(a)	Estimated Average One-Day Impact on Operating Income for 2003(a)	Estimated Average One-Day Impact on Operating Income for 2002	High One-Day Impact on Operating Income for 2003(a)	Low One-Day Impact on Operating Income for 2003(a)
Calculated DER	$ 20	$ 8	$ 14	$ 32	$ 2

(a) These figures include all trading contracts and all undesignated commodity contracts as described in the notes to the consolidated financial statements.

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.

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 fair value of trading contracts by commodity and settlement method as of December 31, 2003.

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Commodity Type

	Fair Value (in millions)
Financial gas and power contracts	$ 498
Physical power contracts	(280)
Physical natural gas contracts	(37)
Refined products/NGL contracts	(4)
Total fair value of contracts	$ 177

See Note 8 to the Consolidated Financial Statements for the Changes in Fair Value of Trading Contracts and Fair Value of Trading Contracts by source and maturity date.

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 payment 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, Asia Pacific 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, 2003. 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, 2003

	% of Total
Investment Grade Externally Rated	74%
Non-Investment Grade Externally Rated	11%
Investment Grade Internally Rated	7%
Non-Investment Grade Internally Rated	8%
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 rating methodologies and credit scoring

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models to develop a public rating equivalent. The total of the unsecured credit exposure included in the table above represents approximately 29% 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, 2003.

Duke Energy had no net exposure to any one customer that represented greater than 10% of the gross fair value of trade accounts receivable, energy trading assets and derivative assets at December 31, 2003. 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. Recent downgrades in Duke Energy s affiliates credit ratings resulted in reductions in Duke Energy s unsecured thresholds granted by counterparties, with Duke Energy posting more collateral to counterparties, and any further downgrade could require the posting of additional collateral. 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 New York Mercantile Exchange-traded futures and options contracts requires daily cash settlement in margin accounts with brokers.

Duke Energy s claims made in the Enron bankruptcy case exceeded its non-collateralized accounting exposure. Bankruptcy claims that exceed this amount primarily relate to termination and settlement rights under normal purchases and normal sales contracts where Enron was the counterparty. (See Note 17 to the Consolidated Financial Statements.)

Substantially all contracts with Enron were completed or terminated prior to December 31, 2001. Duke Energy has continuing contractual relationships with certain Enron affiliates, which are not in bankruptcy. In Brazil, a power purchase agreement between a Duke Energy affiliate, Paranapanema, and Elektro Eletricidade e Servicos S/A (Elektro), a distribution company approximately 100% owned by Enron, will expire December 31, 2005. The contract was executed by Duke Energy s predecessor in interest in Paranapanema, and obligates Paranapanema to provide energy to Elektro on an irrevocable basis for the contract period.

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

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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, 14, and 15 to the Consolidated Financial Statements.)

Based on a sensitivity analysis as of December 31, 2003, it was estimated that if market interest rates average 1% higher (lower) in 2004 than in 2003, interest expense, net of offsetting impacts in interest income, would increase (decrease) by approximately $34 million. Comparatively, based on a sensitivity analysis as of December 31, 2002, had interest rates averaged 1% higher (lower) in 2003 than in 2002, it was estimated that interest expense would have increased (decreased) by approximately $55 million. These amounts include the effects of interest rate hedges and invested cash and were determined by considering the impact of the hypothetical interest rates on the variable-rate securities outstanding as of December 31, 2003 and 2002. The decrease in interest rate sensitivity was primarily due to the decrease in outstanding variable-rate commercial paper and increase in 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 17 to the Consolidated Financial Statements.) As of December 31, 2003 and 2002, 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.

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, 2003 (Duke Energy s measurement date), Duke Energy s pension plan obligation, excluding Westcoast, exceeded the value of the plan assets by $170 million and Duke Energy was therefore required to reduce the minimum liability as prescribed by SFAS No. 87 and SFAS No. 132, Employers Disclosures about Pensions and Postretirement Benefits, by approximately $83 million to $689 million. The $689 million pension liability was a combination of the $170 million excess obligation and $519 million in pre-paid pension assets. The net pension liability as of December 31, 2003 is included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets. The liability was recorded as a reduction to Accumulated Other Comprehensive Income (AOCI), net of income taxes, and did not affect net income for 2003. 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 $36 million minimum pension liability recorded as of December 31, 2003.

Foreign Currency Risk

Duke Energy is exposed to foreign currency risk from investments in international affiliates and businesses owned and operated in foreign countries. 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.

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As of December 31, 2003, 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 $16 million to Duke Energy s Consolidated Statements of Operations. The Consolidated Balance Sheets would be negatively impacted by approximately $480 million currency translation through the cumulative translation adjustment in AOCI.

In 1991, the Argentine peso was pegged to the U.S. dollar at a fixed 1:1 exchange ratio. In December 2001, the Argentine government imposed a restriction that limited cash withdrawals above a certain amount and foreign money transfers. Financial institutions were allowed to conduct limited activity, a holiday was announced, and currency exchange activity was essentially halted. The government also required that all dollar-denominated contracts be converted to pesos. In January 2002, the Argentine government announced the creation of a dual-currency system. Subsequently, however, the Argentine government changed to a managed free-floating currency.

Duke Energy s investment in Argentina was U.S. dollar functional as of December 31, 2001. Once a functional currency determination has been made, that determination must be adhered to consistently, unless significant changes in economic factors indicate that the entity s functional currency has changed. The events in Argentina required a change. In January 2002, the functional currency of Duke Energy s investment in Argentina changed from the U.S. dollar to the Argentine peso. In compliance with SFAS No. 52, Foreign Currency Translation, the change in functional currency was made prospectively. Management believes that the events in Argentina will have no material adverse effect on Duke Energy s future consolidated results of operations, cash flows or financial position.

CURRENT ISSUES

Electric Competition

Wholesale Competition. The Energy Policy Act of 1992 and the Federal Energy Regulatory Commission (FERC s) subsequent rulemaking activities opened the wholesale energy market to competition. Open-access transmission for wholesale customers, as defined by the FERC s rules, provides energy suppliers, including Duke Energy, with opportunities to sell and deliver capacity and energy at market-based prices. From the FERC s open-access rule, Franchised Electric obtained the rights to sell capacity and energy at market-based rates from its own assets, which also allows Franchised Electric to purchase, at attractive rates, a portion of its capacity and energy requirements resulting in lower overall costs to customers. Open access also provides Franchised Electric s existing wholesale customers with competitive opportunities to seek other suppliers for their capacity and energy requirements.

In 1999 and 2000, the FERC issued its Order 2000 and Order 2000-A regarding Regional Transmission Organizations (RTOs). These orders set minimum characteristics and functions RTOs must meet, including independent authority to establish the terms and conditions of transmission service over the facilities they control. The orders provide for an open and flexible RTO structure to meet the needs of the market, and for the possibility of incentive ratemaking and other benefits for transmission owners that participate. The FERC proposes to have RTOs or other independent transmission providers operate transmission systems in all regions of the country.

As a result of these rulemakings, Duke Power and the franchised electric units of two other investor-owned utilities, Carolina Power & Light Company 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. The sponsors expected that GridSouth would be

substantially operational by the FERC s Order 2000 deadline date of December 15, 2001. However, in July 2001 the FERC ordered GridSouth and other utilities in the Southeast to join in a mediation to negotiate terms of a southeastern RTO. It does not appear that the FERC will issue an order specifically based on that proceeding. In 2002, the GridSouth sponsors withdrew their applications to the NCUC and the PSCSC for approval of the transfer of functional control of their electric transmission assets to GridSouth, and announced that development of the GridSouth implementation project had been suspended until the sponsors have an opportunity to further consider regulatory circumstances. Duke Energy believes that more open wholesale electric markets will at some point provide benefits to consumers and other market participants. Duke Energy continues to examine options relative to RTOs in light of the existing complex regulatory environment. Management expects it will recover its investment in GridSouth.

Today, the pace of electricity restructuring varies quite substantially across the U.S. Duke Energy is actively engaged in most markets, particularly those in which it owns assets. Duke Energy continues to believe that wholesale competitive markets bring added value to consumers; therefore, Duke Energy supports the continued restructuring of wholesale electric markets through a disciplined, prudent transition to regional markets. Transforming the current regulated industry into efficient, competitive wholesale and retail electric markets is a complex undertaking, and will continue to require careful planning and coordination between federal and state regulators and other key stakeholders. Duke Energy intends to continue to work with customers, legislators and regulators to address all the important issues. Management currently cannot predict the impact, if any, of these competitive forces on future consolidated results of operations, cash flows or financial position.

Natural Gas Competition

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 and these initiatives generally reflect more light-handed regulation of the natural gas industry.

Retail Competition. Changes in regulation to allow retail competition could affect Duke Energy s natural gas transportation contracts with local natural gas distribution companies. Since natural gas retail deregulation is in the very early stages of development, management believes the effects of this matter will have no material adverse effect on Duke Energy s future consolidated results of operations, cash flows or financial position.

Other Current Issues

For information on other current issues related to Duke Energy, see the following Notes to the Consolidated Financial Statements: Note 4, Notices of Proposed Rulemaking section; Note 17, Environmental and Litigation sections.

New Accounting Standards

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, such financial 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 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 on July 1, 2003.

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As a result of the adoption of SFAS No. 150, Long-term Debt included trust preferred securities which had been previously included on the Consolidated Balance Sheet as Guaranteed Preferred Beneficial Interests in Subordinated Notes of Duke Energy or Subsidiaries. However, upon the adoption of the provisions of FIN 46R as of December 31, 2003, which required deconsolidation of the trust subsidiary, this long-term debt of $876 million has been reclassified as an affiliate debt balance in the Consolidated Balance Sheet. In addition, Long-term Debt, including current maturities, as of December 31, 2003 also included $25 million of preferred stock with sinking fund requirements, which had been previously included on the Consolidated Balance Sheet as Preferred and Preference Stock with Sinking Fund Requirements. In addition, $23 million of DEFS preferred members interest held by ConocoPhillips, which had previously been included on the Consolidated Balance Sheets as Minority Interests was reclassified to Long-term Debt. As of December 31, 2003, DEFS had redeemed all outstanding amounts of the preferred members interest. In accordance with the requirements of SFAS No. 150, prior period amounts have not been reclassified to be in conformity with the current presentation.

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 Noncontrolling Interests under FASB Statement No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity. Duke Energy has a non-controlling interest in a limited life entity in Bolivia, whereby the entity is required to be liquidated 99 years after formation. 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. At December 31, 2003 the fair value of the entity s non-controlling interest of approximately $40 million is approximately $5 million less than its carrying 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 changes could be made by the FASB during such future deliberations. Therefore, Duke Energy is not able to conclude as to whether such future changes would be likely to materially affect the amounts already recorded and disclosed under the provisions of SFAS No. 150.

Revised SFAS No. 132, 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 postretirement plans, such as the following: (1) long-term rate of return on plan assets along with narrative discussion of basis for selecting the rate of return used; (2) 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 by each major asset category and the actual allocation percentage at the measurement date; (3) amount of benefit payments expected to be paid in each of the next five years and the following five year period, in the aggregate; (4) current best estimate of range of contributions expected to be made in following year; (5) the accumulated benefit obligation for defined benefit pension plans; and (6) disclosure of measurement date utilized. Additionally, interim reports require certain additional disclosures related to the components of net periodic pension cost recognized and 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 revised SFAS No. 132 do not change the measurement or recognition provisions of defined benefit pension and postretirement plans as required by previous accounting standards. Except as discussed below, the provisions of revised SFAS No. 132 are effective for fiscal years ending after December 15, 2003 (December 31, 2003 for calendar-year entities) and all interim periods beginning after December 15, 2003 (March 31, 2004 for calendar-year entities). The disclosure provisions of estimated future benefit payments and information about foreign plans are effective for fiscal years ending after June 15, 2004 (December 31, 2004 for calendar-year entities). See Note 21 to the Consolidated Financial Statements for additional disclosures required as of December 31, 2003.

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 is the party that 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, FIN 46 was revised with the issuance of FIN 46R, which supercedes and amends certain provisions of FIN 46. While FIN 46R retains many of the concepts and provisions of FIN 46, it also provides additional guidance related to the application of FIN 46, provides for certain additional scope exceptions, and incorporates several FASB Staff Positions issued related to the application of FIN 46.

The provisions of FIN 46 are immediately applicable to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003 and the provisions of FIN 46R are required to be applied to such entities, except for special-purpose entities, by the end of the first reporting period ending after March 15, 2004 (March 31, 2004 for calendar-year entities). For variable interest entities created, or interests in variable interest entities obtained, on or before January 31, 2003, FIN 46 or FIN 46R is 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 calendar-year entities) and is 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 calendar-year entities). FIN 46 and FIN 46R may be applied prospectively with a cumulative-effect adjustment as of the date it is first applied, or by restating previously issued financial statements with a cumulative-effect adjustment as of the beginning of the first year restated. FIN 46 and FIN 46R also require certain disclosures of an entity s relationship with variable interest entities.

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 46 and continues to assess the existence of any interests in variable interest entities created on or prior to January 31, 2003. Duke Energy currently anticipates certain non-special purpose entities, previously accounted for under the equity method of accounting, will be consolidated by Duke Energy in the first quarter of 2004 under the provisions of FIN 46R. These entities, which are substantive entities, have total assets of approximately $225 million as of December 31, 2003 and total revenue of approximately $150 million for the year ended December 31, 2003. Duke Energy s maximum exposure to loss as a result of its involvement with these entities is approximately $100 million, generally limited to Duke Energy s investment and guarantee obligations in these entities, as of December 31, 2003. Duke Energy adopted the provisions of FIN 46R on December 31, 2003, related to its special-purpose entities consisting of the trust subsidiaries that have issued the trust preferred securities, as discussed in Note 15 to the Consolidated Financial Statements. Since Duke Energy is not the primary beneficiary of such trust subsidiaries, these entities have been deconsolidated in the accompanying Consolidated Financial Statements effective December 31, 2003. This deconsolidation resulted in Duke Energy reflecting affiliate debt to the trusts in Long-term Debt in the Consolidated Balance Sheets. Interest paid to the subsidiary trust will be classified as Interest Expense in the accompanying Consolidated Statements of Operations beginning January 1, 2004 consistent with the classification under SFAS No. 150. Additionally, Duke Energy has a significant variable interest in, but is not the primary beneficiary of, DCS due to certain guarantee obligations as discussed in Note 18 to the Consolidated Financial Statements. As further discussed in Note 18 to the Consolidated Financial Statements, Duke Energy s maximum exposure to loss as a result of its variable interest in DCS cannot be quantified. Duke Energy continues to assess FIN 46R but does not anticipate that it will have a material impact on its consolidated results of operations, cash flows or financial position.

FASB Staff Position (FSP) FAS 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. In January 2004, the FASB staff issued FSP FAS 106-1, which allows a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act), which became law in December 2003. The Act introduced a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health

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care benefit plans. FSP FAS 106-1 allows a sponsor to defer recognizing the effects of the Act in accounting for its postretirement benefit plans under SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions until further authoritative accounting guidance is issued. Duke Energy has a measurement date of September 30th for its SFAS No. 106 postretirement benefit plans and has elected to defer application of SFAS No. 106 to the provisions of the Act under the guidance given in FSP FAS 106-1. Therefore, the accumulated postretirement benefit obligation and net periodic postretirement benefit cost contained in Note 21 to the Consolidated Financial Statements do not reflect the effects of the Act. Specific authoritative guidance on the accounting for the federal subsidy is pending and such guidance, when issued, could require a change to previously reported information. Duke Energy is still reviewing the potential impacts of the Act on its postretirement benefit plans, but currently anticipates it will qualify for the federal subsidy under the Act.

Subsequent Events

On March 1, 2004, Duke Capital Corporation, a Delaware corporation which is a wholly owned subsidiary of Duke Energy, announced that it had changed its form of organization from a corporation to a Delaware limited liability company. The change in form of organization was effected by conversion pursuant to Section 266 of the General Corporation Law of the State of Delaware and Section 18-214 of the Delaware Limited Liability Company Act. Pursuant to the conversion, all rights and liabilities of Duke Capital Corporation vested in Duke Capital LLC, a Delaware limited liability company. This conversion will not have any effect on the Duke Energy consolidated results of operations or financial position.

In the second quarter of 2004, DEFS acquired gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips for a total purchase price approximately $80 million, consisting of $74 million in cash and the assumption of approximately $6 million of liabilities.

On July 2, 2004, Duke Energy realigned certain subsidiaries resulting in all of its wholly owned merchant generation facilities being owned by a newly created entity, Duke Energy Americas, LLC (DEA), a directly wholly owned subsidiary of Duke Capital. DEA and Duke Capital are pass-through entities for US income tax purposes. As a result of these changes, Duke Capital will recognize a federal and state tax expense of approximately $900 million in the third quarter of 2004 from the elimination of the deferred tax assets that existed on its balance sheet prior to the July 2, 2004 reorganization. Correspondingly, Duke Energy, the parent of Duke Capital, will reflect, through consolidation, the elimination of the $900 million deferred tax asset at Duke Capital and the creation of a deferred tax asset of approximately $900 million on its balance sheet. Duke Energy will additionally recognize an approximate $45 million income tax benefit and corresponding deferred tax asset as a result of restating its deferred taxes to reflect a change in state tax rates. In future periods, as these deferred tax assets are converted into cash due to the realization of certain tax losses, Duke Energy intends to infuse the related cash flows back into Duke Capital. Most of these cash benefits result from tax losses arising from the sales of DENA s Southeastern U.S generation assets and the Moapa facility.

Asset Sales

In January 2004, Duke Energy, through its wholly owned subsidiary Duke Energy Royal, LLC, agreed to sell its interest in six energy service agreements and Duke Energy Huntington Beach, LLC. In February 2004, DEFS entered into a purchase and sale agreement to sell certain gas gathering and processing plant assets in West Texas. Also in February 2004, DEM sold its 15-percent ownership interest in Caribbean Nitrogen Company. Additionally, during the first and second quarter of 2004, DENA sold turbines and surplus equipment. In total, all of these transactions resulted in cash proceeds of approximately $209 million and a net gain of approximately $14 million.

During the first and second quarter of 2004, DETM sold certain physical power contracts in which it held a liability position. As part of the sale, DETM paid a third party an immaterial amount, which approximated the carrying value of the contracts at December 31, 2003.

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In the first quarter of 2004, Duke Energy recorded a $238 million after-tax gain related to International Energy s Asia Pacific power generation and natural transmission businesses. The estimated fair value, less costs to sell was classified as held for sale as of December 31, 2003. The gain recorded in the first quarter of 2004 restores the loss recorded during the fourth quarter of 2003. The December 31, 2003 estimated fair value was based upon third-party bids received by International Energy. During the first quarter, Duke Energy determined that it was likely a bid in excess of the originally determined fair value would be accepted. In April 2004, Duke Energy completed the sale of the Asia-Pacific businesses to Alinta Ltd. for a gross sales price of approximately $1.2 billion. This resulted in recording an additional $40 million after-tax gain in the second quarter. Duke Energy received approximately $390 million of cash proceeds, net of debt repayment of approximately $840 million of debt retired (as a non-cash financing activity) as part of the Asia-Pacific operations. The $840 million does not include approximately $50 million of Australian debt which has been placed in trust and fully funded in connection with the closing of the sale transaction and will be repaid in September 2004. This trust is included in the Consolidated Financial Statements as Duke Energy is the primary beneficiary of the trust and, therefore, is required to consolidate the trust under provisions of FIN 46. The Asia-Pacific debt had been classified as Current and Non-Current Liabilities Associated with Assets Held for Sale on the December 31, 2003 Consolidated Balance Sheet. All gains related to this transaction and the results of operations for these assets are included in Net Gain (Loss) on Dispositions, net of tax, within Discontinued Operations, in the 2004 Consolidated Statements of Operations.

On May 4, 2004 Duke Energy announced the sale of its merchant generation business in the southeastern United States to KGen Partners LLC (KGen). The sale transaction has obtained all required regulatory approvals and consents and closed on August 5, 2004. This transaction resulted in a cumulative pre-tax loss of approximately $367 million, of which approximately $360 million was recognized in the first quarter of 2004 to reduce the carrying value of those assets to their estimated fair values, while the remaining amount of the loss will be recognized by Duke Energy in the third quarter of 2004. Subsequent to the closing of the transaction, DENA will continue to provide certain transitional services and operating and maintenance services for the sold assets, including potential exercise of limited plant dispatch rights for a period not to exceed six months form the date of August 5, 2004. DENA anticipates recognizing the sale transaction in the third quarter of 2004, pending resolution of certain continuing involvement provisions.

In conjunction with the sale of DENA s southeastern assets to KGen, Duke Energy 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 its Murray facility to Georgia Power. Duke Energy is the primary obligor to the letter of credit provider, but KGen has an obligation to reimburse Duke Energy for any payments made by it under the letter of credit, as well as expenses incurred by Duke Energy in connection with the letter of credit. Duke Energy will operate the Murray facility under an operation and maintenance agreement with a KGen subsidiary.

As disclosed in Note 12 to the Consolidated Financial Statements, Subsequent Events, in Duke Energy s Form 10-Q for June 30, 2003, Duke Energy announced the sale of a 25% undivided interest in the Duke Energy Vermillion facility. In May 2004, the sale of the 25% undivided interest in the Vermillion facility was completed for approximately $44 million. A loss on the sale of approximately $18 million was recorded in the third quarter of 2003. Duke Energy will continue to own the remaining 75% interest in the facility.

In May 2004, Duke Energy reached an agreement to sell its 30% equity interest in Compañia de Nitrógeno de Cantarell, S.A. de C.V., nitrogen production and delivery facility in the Bay of Campeche, Gulf of Mexico for approximately $60 million. Duke Energy recorded a non-cash charge of $13 million to Operation, Maintenance and Other expenses on the Consolidated Statements of Operations in the first quarter of 2004 in anticipation of this sale. The sale is expected to close in the third quarter of 2004.

In the second quarter of 2004, Duke Energy announced an agreement to sell one of DENA s deferred facilities, Moapa, to Nevada Power Company for approximately $182 million in cash, with closing expected

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during the fourth quarter of 2004 pending regulatory approvals. The Moapa asset was classified as held for sale in the June 30, 2004 Consolidated Balance Sheet. This facility will not be reported in Discontinued Operations as, among other considerations, the facility never entered into operations and has no associated historical operating revenues or costs.

Debt and Financing Related Matters

In March 2004, Duke Energy redeemed the entire issue of 7.20% Duke Energy debt to an affiliate due 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 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, Duke Capital purchased $101 million of its outstanding notes in the open market. These purchases included $49 million of Duke Capital 5.50% senior notes due March 1, 2014 and $52 million of Duke Capital 4.37% senior notes due March 1, 2009. The securities were redeemed at the then current market price plus accrued interest.

In May 2004, Duke Energy redeemed Duke Energy Series C 6.60% Senior Notes due 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 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. Duke Energy issued 35,000,000 Equity Units in March 2001 at $25 per unit. 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. The rate was 0.6414 shares of stock per Equity Unit.

In June 2004, Westcoast Energy, Inc. 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 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 July 2004, Duke Energy announced that on August 31, 2004, it will redeem the entire issue of Duke Capital Financing Trust III 8 $^{3}/8$% Trust Preferred Securities due August 31, 2029 with a face value of $250 million. As the securities are being redeemed at par, security holders will receive $25 per preferred security held, plus accrued and unpaid distributions to the redemption date. Additionally, Duke Energy plans to remarket $750 million of its 4.32% senior notes, due in 2006, underlying its 8.00% Equity Units on August 11, 2004. Proceeds from the remarketed notes will be held by a collateral agent and used to purchase U.S. Treasury securities to satisfy the forward stock purchase contract component of the Equity Units in November 2004.

Regulatory Matters

Bulk Power Marketing Profit Sharing. On June 9, 2004, the NCUC approved Duke Energy s proposal to share an amount equal to 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

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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 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.

On June 29, 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 proposed to establish an entity to receive 50% of the South Carolina allocable share of the BPM Profits to support public assistance programs, education programs to promote economic development, and grants to promote the attraction and retention of industrial customers. The PSCSC has not addressed the appropriateness of 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. The 2004 year-to-date total of $27 million of shared profits was recorded as a $14 million decrease to revenues (for the portion related to reduced industrial customers rates) and a $13 million charge to expenses (for the portion related to donations to charitable, educational and economic development programs in North Carolina and South Carolina) in the second quarter of 2004.

For information on additional subsequent events related to debt and other financing matters refer to Financing Cash Flows and Liquidity Significant Financing Activities and Other Financing Matters sections. For information on additional subsequent events related to Regulatory Matters refer to Note 4 to the Consolidated Financial Statements. For information on subsequent events related to litigation and contingencies refer to Note 17 Litigation to the Consolidated Financial Statements. For information on subsequent events related to the MOX guarantee refer to Note 18 to the Consolidated Financial Statements.

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.

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Item 8. Financial Statements and Supplementary Data.

DUKE ENERGY CORPORATION

Consolidated Statements Of Operations

	Years Ended December 31,		
	2003	2002	2001
	(as Revised, See Note 24)		
	(In millions, except per-share amounts)		
Operating Revenues			
Non-regulated electric, natural gas, natural gas liquids, and other	$ 14,186	$ 8,818	$ 11,936
Regulated electric	5,026	4,880	5,088
Regulated natural gas	2,942	2,200	922
Total operating revenues	22,154	15,898	17,946
Operating Expenses			
Natural gas and petroleum products purchased	11,473	5,382	6,909
Fuel used in electric generation and purchased power	2,087	2,191	2,022
Operation and maintenance	3,777	3,313	3,712
Depreciation and amortization	1,799	1,511	1,258
Property and other taxes	526	534	430
Impairment and other related charges	2,956	364	
Impairment of goodwill	254		36
Total operating expenses	22,872	13,295	14,367
Gains on Sales of Investments in Commercial and Multi-family Real Estate	84	106	106
(Losses) Gains on Sales of Other Assets, net	(199)	32	238
Operating (Loss) Income	(833)	2,741	3,923
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	123	218	164
Gains on sales of equity investments	279	32	
Other income and expenses, net	154	129	147
Total other income and expenses	556	379	311
Interest Expense	1,380	1,097	760
Minority Interest Expense	61	116	326
(Loss) Earnings From Continuing Operations Before Income Taxes	(1,718)	1,907	3,148
Income Tax (Benefit) Expense From Continuing Operations	(709)	611	1,149
(Loss) Income From Continuing Operations	(1,009)	1,296	1,999

Discontinued Operations			
Net operating loss, net of tax	(23)	(262)	(5)
Net loss on dispositions, net of tax	(129)		
Loss From Discontinued Operations	(152)	(262)	(5)
(Loss) Income Before Cumulative Effect of Change in Accounting Principle	(1,161)	1,034	1,994
Cumulative Effect of Change in Accounting Principle, net of tax and minority interest	(162)		(96)
Net (Loss) Income	(1,323)	1,034	1,898
Dividends and Premiums on Redemption of Preferred and Preference Stock	15	13	14
(Loss) Earnings Available For Common Stockholders	$ (1,338)	$ 1,021	$ 1,884
Common Stock Data			
Weighted-average shares outstanding	903	836	767
(Loss) Earnings per share (from continuing operations)			
Basic	$ (1.13)	$ 1.53	$ 2.59
Diluted	$ (1.13)	$ 1.53	$ 2.57
Loss per share (from discontinued operations)			
Basic	$ (0.17)	$ (0.31)	$ (0.01)
Diluted	$ (0.17)	$ (0.31)	$ (0.01)
(Loss) Earnings per share (before cumulative effect of change in accounting principle)			
Basic	$ (1.30)	$ 1.22	$ 2.58
Diluted	$ (1.30)	$ 1.22	$ 2.56
(Loss) Earnings per share			
Basic	$ (1.48)	$ 1.22	$ 2.45
Diluted	$ (1.48)	$ 1.22	$ 2.44
Dividends per share	$ 1.10	$ 1.10	$ 1.10

See Notes to Consolidated Financial Statements.

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DUKE ENERGY CORPORATION

Consolidated Balance Sheets

	December 31,	
	2003	**2002**
	(as Revised, see Note 24) (In millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,160	$ 874
Receivables (net of allowance for doubtful accounts of $280 at 2003 and $349 at 2002)	2,888	4,861
Inventory	941	971
Assets held for sale	424	
Unrealized gains on mark-to-market and hedging transactions	1,566	2,144
Other	694	887
Total current assets	7,673	9,737
Investments and Other Assets		
Investments in unconsolidated affiliates	1,398	2,015
Nuclear decommissioning trust funds	925	708
Goodwill	3,962	3,747
Notes receivable	260	589
Unrealized gains on mark-to-market and hedging transactions	1,857	2,480
Assets held for sale	1,444	
Investments in residential, commercial and multi-family real estate (net of accumulated depreciation of $32 at 2003 and 2002)	1,331	1,440
Other	1,117	1,645
Total investments and other assets	12,294	12,624
Property, Plant and Equipment		
Cost	46,009	47,368
Less accumulated depreciation and amortization	12,139	11,266
Net property, plant and equipment	33,870	36,102
Regulatory Assets and Deferred Debits		
Deferred debt expense	275	263
Regulatory assets related to income taxes	1,152	936
Other	939	460
Total regulatory assets and deferred debits	2,366	1,659

Total Assets	$ 56,203	$ 60,122

See Notes to Consolidated Financial Statements.

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DUKE ENERGY CORPORATION

Consolidated Balance Sheets (Continued)

	December 31,	
	2003	**2002**
	(as Revised, see Note 24) (In millions)	
LIABILITIES AND COMMON STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 2,331	$ 3,637
Notes payable and commercial paper	130	915
Taxes accrued		156
Interest accrued	304	310
Liabilities associated with assets held for sale	651	
Current maturities of long-term debt and preferred stock	1,200	1,331
Unrealized losses on mark-to-market and hedging transactions	1,283	1,918
Other	1,799	1,770
Total current liabilities	7,698	10,037
Long-term Debt, including debt to affiliates of $876 at 2003	20,622	20,221
Deferred Credits and Other Liabilities		
Deferred income taxes	4,120	4,834
Investment tax credit	165	176
Unrealized losses on mark-to-market and hedging transactions	1,754	1,548
Liabilities associated with assets held for sale	737	
Other	5,524	4,893
Total deferred credits and other liabilities	12,300	11,451
Commitments and Contingencies		
Guaranteed Preferred Beneficial Interests in Subordinated Notes of Duke Energy Corporation or Subsidiaries		1,408
Minority Interests	1,701	1,904
Preferred and Preference Stock		
Preferred and preference stock with sinking fund requirements		23
Preferred and preference stock without sinking fund requirements	134	134
Total preferred and preference stock	134	157
Common Stockholders Equity		
Common stock, no par, 2 billion shares authorized; 911 million and 895 million shares outstanding at December 31, 2003 and 2002, respectively	9,519	9,236
Retained earnings	4,060	6,417

Accumulated other comprehensive income (loss)	169	(709)
Total common stockholders equity	13,748	14,944
Total Liabilities and Common Stockholders Equity	$ 56,203	$ 60,122

See Notes to Consolidated Financial Statements.

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DUKE ENERGY CORPORATION

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2003	2002	2001
	(as Revised, See Note 24) (In millions)		
Cash Flows From Operating Activities			
Net (loss) income	$ (1,323)	$ 1,034	$ 1,898
Adjustments to reconcile net (loss) income to net cash provided by operating activities			
Depreciation and amortization (including amortization of nuclear fuel)	1,987	1,692	1,450
Cumulative effect of change in accounting principle	162		96
Gains on sales of investments in commercial and multi-family real estate	(103)	(106)	(106)
Gain on sales of equity investments and other assets	(86)	(81)	(238)
Impairment charges	3,495	545	36
Deferred income taxes	(534)	495	129
Purchased capacity levelization	194	175	156
Contribution to company-sponsored pension plan	(181)		
(Increase) decrease in			
Net realized and unrealized mark-to-market and hedging transactions	(15)	596	91
Receivables	1,126	12	3,166
Inventory	(30)	134	(192)
Other current assets	(77)	(335)	694
Increase (decrease) in			
Accounts payable	(1,030)	798	(3,545)
Taxes accrued	(168)	(332)	183
Other current liabilities	79	(194)	325
Capital expenditures for residential real estate	(196)	(179)	(230)
Cost of residential real estate sold	167	117	90
Other, assets	(29)	200	(11)
Other, liabilities	(19)	(372)	(243)
Net cash provided by operating activities	3,419	4,199	3,749
Cash Flows From Investing Activities			
Capital expenditures, net of refund	(2,275)	(4,745)	(5,700)
Investment expenditures	(290)	(641)	(1,093)
Acquisition of Westcoast Energy Inc., net of cash acquired		(1,707)	
Proceeds from sales of commercial and multi-family real estate	314	169	378
Net proceeds from the sales of equity investment and other assets, and sales of and collections on notes receivable	1,966	516	943
Other	(136)	(53)	37
Net cash used in investing activities	(421)	(6,461)	(5,435)
Cash Flows From Financing Activities			
Proceeds from the			
Issuance of long-term debt	3,009	5,114	2,673
Issuance of common stock and common stock related to employee benefit plans	277	1,323	1,432
Payments for the redemption of			
Long-term debt	(2,849)	(1,837)	(1,298)
Preferred and preference stock and preferred member interests	(38)	(88)	(33)
Guaranteed preferred beneficial interests in subordinated notes	(250)		
Notes payable and commercial paper	(1,702)	(1,067)	(246)

Distributions to minority interests	(2,508)	(2,260)	(3,063)
Contributions from minority interests	2,432	2,535	2,733
Dividends paid	(1,051)	(938)	(871)
Other	23	64	27
Net cash (used in) provided by financing activities	(2,657)	2,846	1,354
Changes in cash and cash equivalents associated with assets held for sale	(55)		
Net increase (decrease) in cash and cash equivalents	286	584	(332)
Cash and cash equivalents at beginning of period	874	290	622
Cash and cash equivalents at end of period	$ 1,160	$ 874	$ 290
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$ 1,324	$ 1,011	$ 733
Cash (refunded) paid for income taxes	$ (18)	$ 344	$ 770
Significant non-cash transactions:			
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.

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DUKE ENERGY CORPORATION

Consolidated Statements of Common Stockholders Equity

and Comprehensive Income (Loss)

	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
				(In millions)			
Balance December 31, 2000	739	$ 4,797	$ 5,379	$ (120)	$	$	$ 10,056
Net income			1,898				1,898
Other Comprehensive Income							
Cumulative change in accounting principle(a)					(921)		(921)
Foreign currency translation adjustments				(187)			(187)
Net unrealized gains on cash flow hedges(c)					1,324		1,324
Reclassification into earnings from cash flow hedges(d)					84		84
Total comprehensive income							2,198
Dividend reinvestment and employee benefits	13	329					329
Equity offering	25	1,091					1,091
Common stock dividends, including equity units contract adjustment			(973)				(973)
Preferred and preference stock dividends			(14)				(14)
Other capital stock transactions, net			2				2
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(c)					37		37
Reclassification into earnings from cash flow hedges(d)					(102)		(102)
Minimum pension liability adjustment(e)						(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, including equity units contract adjustment			(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(b)				962			962
Net unrealized gains on cash flow hedges(c)					116		116
Reclassification into earnings from cash flow hedges(d)					(240)		(240)
Minimum pension liability adjustment(e)						40	40
Total comprehensive loss							(445)
Dividend reinvestment and employee benefits	16	283	(6)				277
Common stock dividends, including equity units contract adjustment			(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

(a) Cumulative change in accounting principle, net of $573 tax benefit in 2001.
(b) Foreign currency translation adjustments, net of $114 tax benefit in 2003
(c) Net unrealized gains on cash flow hedges, net of $49 tax expense in 2003, $72 tax expense in 2002 and $748 tax expense in 2001.
(d) Reclassification into earnings from cash flow hedges, net of $130 tax benefit in 2003, $94 tax benefit in 2002 and $116 tax expense in 2001.
(e) Minimum pension liability adjustment, net of $27 tax expense in 2003 and $309 tax benefit in 2002.

See Notes to Consolidated Financial Statements.

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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements

For the Years Ended December 31, 2003, 2002 and 2001

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 an affiliated real estate operation. The Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of Duke Energy and all majority-owned subsidiaries, except for the trust subsidiaries that have issued the trust preferred securities which have been deconsolidated upon the adoption of Financial Accounting Standards Board (FASB) Interpretation No. 46 (revised) (FIN 46R), Consolidation of Variable Interest Entities.

Use of Estimates. Conformity with generally accepted accounting principles (GAAP) in the U.S. requires management to make 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 of current and expected future events, actual results could be different from those estimates.

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 12). Also, beginning in the third quarter of 2003, Duke Energy elected to begin netting certain receivables and payables with common counterparties under the provisions of FASB Interpretation No. 39 (FIN 39), Offsetting of Amounts Related to Certain Contracts (an Interpretation of APB Opinion No. 10 and SFAS No. 105). For comparability purposes, balances of certain receivables and payables in the comparative balance sheet presented have been netted. Such netting reduced current assets and current liabilities as of December 31, 2002 by approximately $2 billion.

Included in the reclassified amounts are increases in both sales of natural gas and petroleum products, and in purchases of natural gas and petroleum products in the amount of $805 million for the year ended December 31, 2002 and $639 million for the year ended December 31, 2001 related to the Field Services segment. Management has concluded that these reclassifications are not material to the fair presentation of Duke Energy s consolidated financial statements.

In accordance with industry-wide guidance received from the Securities and Exchange Commission (SEC) in February 2004, Duke Energy has reclassified as other liabilities approximately $1,160 million of cost of removal and nuclear decommissioning costs as of December 31, 2002 which were classified as accumulated depreciation. See Notes 4 and 7 for further information.

For information related to certain reclassifications made in connection with Crescent Resources LLC (Crescent) activities see Note 24.

Cash and Cash Equivalents. All highly liquid investments with maturities of three months or less at the date of purchase are considered cash equivalents.

Inventory. Inventory consists primarily of materials and supplies; natural gas and natural gas liquid 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, except for inventory previously held for trading, which was recorded at fair value through December 31, 2002, the date before the accounting rule changed.

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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

Components of Inventory

	December 31,	
	2003	2002
	(in millions)	
Materials and supplies	$ 445	$ 433
Natural gas	299	271
Coal	87	84
Petroleum products	110	167
Trading mark-to-market inventory		16
Total inventory	$ 941	$ 971

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 Statement of Financial Accounting Standards (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. Prior to 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 for Contracts Involved in Energy Trading and Risk Management Activities, certain non-derivative energy and energy-related trading contracts were also 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 EITF Issue No. 02-03, Duke Energy designated all energy commodity derivatives as either trading or non-trading. For each of the Duke Energy s derivatives, the accounting method and presentation of gains and losses, or revenue and expense in the Consolidated Statements of Operations is shown below.

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Trading derivatives	Mark-to-market(a)	Net basis in Non-regulated Electric, Natural Gas, Natural Gas Liquids, 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	Gross basis in the same income statement category as the related hedged item
Normal purchase or normal sale	Accrual	Gross basis upon settlement in the corresponding income statement category based on commodity type
Undesignated	Mark-to-market	Net basis in the related income statement category for interest rate, currency and commodity derivative.

(a) An accounting method whereby the change in the fair value of the asset or liability is recognized in the Consolidated Statements of Operations during the current period.

(b) An accounting method whereby there is only limited recognition in the Consolidated Statements of Operations for changes in fair value of a contract until the service is provided or the associated delivery period occurs except to the extent a cash flow or fair value hedge is ineffective.

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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements   Continued

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 trading 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 FIN 39 are met, Duke Energy presents its derivative assets and liabilities, and accompanying receivables and payables, on a net basis in the accompanying 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 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 accounting method 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.

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 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, unless otherwise noted.

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

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

Electricity to certain 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 mark-to-market method 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 verify 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. Valuation adjustments for performance and market risk, and administration costs are used to adjust the fair value of the contract to the gain or loss ultimately recognized in the Consolidated Balance Sheets. For derivatives recognized under the mark-to-market accounting method, valuation adjustments are also recognized in the Consolidated Statements of Operations.

Goodwill. Prior to the adoption of SFAS No. 142, Goodwill and Other Intangible Assets, Duke Energy amortized goodwill on a straight-line basis over the useful lives of the acquired assets, ranging from 10 to 40 years. Duke Energy adopted the provisions of SFAS No. 142 on January 1, 2002. Under the provisions of SFAS No. 142, goodwill is no longer amortized. Duke Energy has designated August 31 as the date it performs the annual review for impairment for its reporting units, except for Field Services, whose date has been designated as September 30. Under the provisions of SFAS No. 142, Duke Energy performs the annual review for impairment at the reporting unit level, which Duke Energy has determined to be an operating segment or one level below.

Impairment testing of goodwill consists of a two-step process. The first step involves a comparison of the 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 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.

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 4.16% for 2003, 4.32% for 2002 and 4.01% for 2001. 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 CORPORATION

Notes To Consolidated Financial Statements Continued

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, and include real estate properties being held for resale, 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, as well as tax-deferred investments being held by qualified intermediaries for future real estate investments. Proceeds from sales of residential properties are presented as revenues and the cost of properties sold are included in operating and maintenance expenses 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 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. Based on current market conditions in the merchant energy industry, it is reasonably possible that Duke Energy s estimate of fair value of the long-lived assets impaired during 2003 could change and the change would impact the consolidated results of operations.

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 in the Consolidated Statements of Operations. If an asset held for sale does not have clearly distinguishable operations and cash flows, impairments and gains or losses on sales are recorded as (Losses) Gains 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.

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

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

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 below.)

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 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 in the rate-setting process in a period different from the period in which the costs would be charged to expense 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.

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.

Stock-Based Compensation. Duke Energy accounts for its stock-based compensation arrangements under the intrinsic value recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and the FASB Interpretation No. 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 fixed stock options with pro-rata vesting is recognized in accordance with FASB Interpretation No. 28, Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans.

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Notes To Consolidated Financial Statements Continued

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 FASB Statement No. 123).

Pro Forma Stock-Based Compensation

	For the years ended December 31,		
	2003	**2002**	**2001**
	(in millions, except per share amounts)		
(Loss) earnings available for common stockholders, as reported	$ (1,338)	$ 1,021	$ 1,884
Add: stock-based compensation expense included in reported net (loss) income, net of related tax effects	6	9	9
Deduct: total stock-based compensation expense determined under fair value-based method for all awards, net of related tax effects	(30)	(70)	(31)
Pro forma (loss) earnings available for common stockholders, net of related tax effects	$ (1,362)	$ 960	$ 1,862
(Loss) earnings per share			
Basic as reported	$ (1.48)	$ 1.22	$ 2.45
Basic pro forma	$ (1.51)	$ 1.15	$ 2.42
Diluted as reported	$ (1.48)	$ 1.22	$ 2.44
Diluted pro forma	$ (1.51)	$ 1.15	$ 2.41

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 kilowatt hour 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.

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 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.

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.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

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 $6 million in 2003, $24 million in 2002 and $43 million in 2001.

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 $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. The total amount of AFUDC included in the Consolidated Statements of Operations was $39 million in 2001, which consisted of an equity component of $28 million and an interest expense component of $11 million.

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.

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 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

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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 non-trading 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, 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 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 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.

Duke Energy adopted SFAS No. 133 as amended and interpreted on January 1, 2001. In accordance with the transition provisions of SFAS No. 133, Duke Energy recorded a net-of-tax cumulative effect adjustment of $96 million, or $0.13 per basic share was recorded in the first quarter of 2001 as a reduction in earnings. The net-of-tax cumulative effect adjustment reducing AOCI and Common Stockholders Equity was $921 million.

New Accounting Standards. The following new accounting standards have been 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. 146, Accounting for Costs Associated with Exit or Disposal Activities. In June 2002, the FASB issued SFAS No. 146 which addresses accounting for restructuring and similar costs. SFAS No. 146 supersedes previous accounting guidance, principally EITF Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a

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Restructuring). Duke Energy has adopted the provisions of SFAS No. 146 for restructuring activities initiated after December 31, 2002. SFAS No. 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF Issue No. 94-3, a liability for an exit cost was recognized on the date of Duke Energy s commitment to an exit plan. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Accordingly, SFAS No. 146 will affect the timing of recognizing future restructuring costs as well as the amounts recognized as liabilities.

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. The 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 are to be applied prospectively for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. SFAS No. 149 provisions that resulted from the DIG process that became effective in quarters beginning before June 15, 2003 continue to be applied based upon 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 policy for accounting 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 following any modifications to these contracts, as long as the requirements for applying the normal purchases and normal sales exception are met.

On June 25, 2003, the FASB cleared the guidance contained in DIG Issue C20, Scope Exceptions: Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature. DIG Issue C20, which applies only to the guidance in paragraph 10(b) of FASB No. 133 and not in reference to embedded derivatives, describes circumstances in which the underlying in a price adjustment clause incorporated into a contract that otherwise satisfies the requirements for the normal purchases and normal sales exception would be considered to be not clearly and closely related to the asset being sold or purchased. The guidance in DIG Issue C20 was effective for Duke Energy on October 1, 2003. Duke Energy s review of existing contracts designated as normal purchases and normal sales under FASB No. 133 yielded no instances where an embedded price adjustment clause was not clearly and closely related to the contract s underlying. As a result, this issue did not have a material impact on Duke Energy s consolidated results of operations, cash flows or financial position.

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, such financial 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 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 on July 1, 2003.

As a result of the adoption of SFAS No. 150, Long-term Debt included trust preferred securities which had been previously included on the Consolidated Balance Sheet as Guaranteed Preferred Beneficial Interests in Subordinated Notes of Duke Energy or Subsidiaries. However, upon the adoption of the provisions of FIN 46R

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as of December 31, 2003, which required deconsolidation of the trust subsidiary, this long-term debt of $876 million has been reclassified as an affiliate debt balance in the Consolidated Balance Sheet. In addition, Long-term Debt, including current maturities, as of December 31, 2003 also included $25 million of preferred stock with sinking fund requirements, which had been previously included on the Consolidated Balance Sheet as Preferred and Preference Stock with Sinking Fund Requirements. In addition, $23 million of Duke Energy Field Services, LLC s (DEFS) preferred members interest held by ConocoPhillips, which had previously been included on the Consolidated Balance Sheets as Minority Interests was reclassified to Long-term Debt. As of December 31, 2003, DEFS had redeemed all outstanding amounts of the preferred members interest. In accordance with the requirements of SFAS No. 150, prior period amounts have not been reclassified to be in conformity with the current presentation.

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 Noncontrolling Interests under FASB Statement No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity. Duke Energy has a non-controlling interest in a limited life entity in Bolivia, whereby the entity is required to be liquidated 99 years after formation. 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. At December 31, 2003 the fair value of the entity s non-controlling interest of approximately $40 million approximates its carrying 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 changes could be made by the FASB during such future deliberations. Therefore, Duke Energy is not able to conclude as to whether such future changes would be likely to 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. Upon application of EITF Issue No. 01-08, 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 and storage services in the arrangements are required to recognize assets on their balance sheets. The consensus is being applied prospectively to arrangements agreed to, modified, or acquired in business combinations 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

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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 the relevant facts and circumstances and the economic substance of the transaction. In analyzing the facts and circumstances, EITF Issue No. 99-19, and 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 have been issued by the authoritative accounting body, but have not yet been adopted or fully adopted by Duke Energy as of December 31, 2003.

Revised SFAS No. 132, 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 postretirement plans, such as the following: (1) long-term rate of return on plan assets along with narrative discussion of basis for selecting the rate of return used; (2) 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 by each major asset category and the actual allocation percentage at the measurement date; (3) amount of benefit payments expected to be paid in each of the next five years and the following five year period, in the aggregate; (4) current best estimate of range of contributions expected to be made in following year; (5) the accumulated benefit obligation for defined benefit pension plans; and (6) disclosure of measurement date utilized. Additionally, interim reports require certain additional disclosures related to the components of net periodic pension cost recognized and 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 revised SFAS No. 132 do not change the measurement or recognition provisions of defined benefit pension and postretirement plans as required by previous accounting standards. Except as discussed below, the provisions of revised SFAS No. 132 are effective for fiscal years ending after December 15, 2003 (December 31, 2003 for calendar-year entities) and all interim periods beginning after December 15, 2003 (March 31, 2004 for calendar-year entities). The disclosure provisions of estimated future benefit payments and information about foreign plans are effective for fiscal years ending after June 15, 2004 (December 31, 2004 for calendar-year entities). See Note 21 for additional disclosures required as of December 31, 2003.

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 is the party that 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 46R, which supercedes and amends certain provisions of FIN 46. While FIN 46R retains many of the concepts and provisions of FIN 46, it also provides additional guidance related to the application of FIN 46, provides for certain additional scope exceptions, and incorporates several FASB Staff Positions issued related to the application of FIN 46.

The provisions of FIN 46 are immediately applicable to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003 and the provisions of FIN 46R are required to be applied to such 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 is 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 calendar-year entities) and is 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 calendar-year entities). FIN 46 and FIN 46R may be applied

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prospectively with a cumulative-effect adjustment as of the date it is first applied, or by restating previously issued financial statements with a cumulative-effect adjustment as of the beginning of the first year restated. FIN 46 and FIN 46R also require certain disclosures of an entity s relationship with variable interest entities.

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 46 and continues to assess the existence of any interests in variable interest entities created on or prior to January 31, 2003. Duke Energy currently anticipates certain non-special purpose entities, previously accounted for under the equity method of accounting, will be consolidated by Duke Energy in the first quarter of 2004 under the provisions of FIN 46R. These entities, which are substantive entities, have total assets of approximately $225 million as of December 31, 2003 and total revenue of approximately $150 million for the year ended December 31, 2003. Duke Energy s maximum exposure to loss as a result of its involvement with these entities is approximately $100 million, generally limited to Duke Energy s investment and guarantee obligations in these entities, as of December 31, 2003. Duke Energy adopted the provisions of FIN 46R on December 31, 2003, related to its special-purpose entities consisting of the trust subsidiaries that have issued the trust preferred securities, as discussed in Note 15. Since Duke Energy is not the primary beneficiary of such trust subsidiaries, these entities have been deconsolidated in the accompanying Consolidated Financial Statements effective December 31, 2003. This deconsolidation resulted in Duke Energy reflecting affiliate debt to the trusts in Long-term Debt in the Consolidated Balance Sheets. Interest paid to the subsidiary trust is classified as Interest Expense in the accompanying Consolidated Statements of Operations consistent with the classification under SFAS No. 150, as discussed above. Additionally, Duke Energy has a significant variable interest in, but is not the primary beneficiary of, Duke COGEMA Stone & Webster, LLC (DCS) due to certain guarantee obligations as discussed in Note 18. As further discussed in Note 18, Duke Energy s maximum exposure to loss as a result of its variable interest in DCS cannot be quantified. Duke Energy continues to assess FIN 46R but does not anticipate that it will have a material impact on its consolidated results of operations, cash flows or financial position.

FASB Staff Position (FSP) FAS 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. In January 2004, the FASB staff issued FSP FAS 106-1, which allows a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act), which became law in December 2003. The Act introduced a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans. FSP FAS 106-1 allows a sponsor to defer recognizing the effects of the Act in accounting for its postretirement benefit plans under SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions until further authoritative accounting guidance is issued. Duke Energy has a measurement date of September 30 for its SFAS No. 106 postretirement benefit plans and has elected to defer application of SFAS No. 106 to the provisions of the Act under the guidance given in FSP FAS 106-1. Therefore, the accumulated postretirement benefit obligation and net periodic postretirement benefit cost contained in Note 21 do not reflect the effects of the Act. Specific authoritative guidance on the accounting for the federal subsidy is pending and such guidance, when issued, could require a change to previously reported information. Duke Energy is still reviewing the potential impacts of the Act on its postretirement benefit plans, but currently anticipates it will qualify for the federal subsidy under the Act.

2. Business Acquisitions and Dispositions

Business 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 is recorded as goodwill. The allocation

DUKE ENERGY CORPORATION

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of the purchase price may be adjusted if additional information on contingencies existing at the date of acquisition becomes available within one year after the acquisition, and longer for certain income tax items.

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.

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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 periods presented.

Consolidated Pro Forma Results for Duke Energy, including Westcoast (unaudited)

	For the years ended December 31,	
	2002	2001
	(in millions, except per share amounts)	
Income Statement Data		

Operating revenues	$ 16,216	$ 20,213
Income before cumulative effect of change in accounting principle	1,071	2,189
Cumulative effect of change in accounting principle, net of tax		(96)
Preferred and preference stock dividends	13	14
Earnings available to common stockholders	$ 1,058	$ 2,079
Common Stock Data		
Weighted-average shares outstanding	846	817
Earnings per share (before cumulative effect of change in accounting principle)		
Basic	$ 1.25	$ 2.66
Diluted	$ 1.25	$ 2.63
Earnings per share		
Basic	$ 1.25	$ 2.54
Diluted	$ 1.25	$ 2.52

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Dispositions. The following table details proceeds from the sale of Duke Energy s assets and businesses for 2003 and 2002.

Proceeds from Sales of Assets and Businesses

	For the years ended December 31,	
	2003	**2002**
	(in millions)	
Sales of discontinued operations (see Note 12)(a)	$ 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)	1,190	214
Cash disposed of in sales	(16)	
Net proceeds, including debt assumed by buyers	2,110	312
Debt assumed by buyers	(387)	
Net proceeds included in the Consolidated Statements of Cash Flows(d)	$ 1,723	$ 312

(a) 2003 includes $259 million of debt assumed by buyer
(b) 2003 includes $58 million of debt assumed by buyer
(c) 2003 includes $70 million of debt assumed by buyer
(d) Excludes investing activities related to sales and collections of notes receivable of $243 million for 2003 and $204 million for 2002, and proceeds from sales of Crescent s commercial and multi-family real estate of $314 million for 2003 and $169 million for 2002

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 Gains on Sales 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 12, 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 Gains on Sales 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 natural gas liquids plant, Foothills Pipe Lines Ltd., and Vector Pipeline; 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 Gains on Sales of Equity Investments in the Consolidated Statements of Operations. Significant sales included Field Services Class B units of TEPPCO Partners, L.P.

Duke Energy North America s (DENA s) asset sales totaled $372 million in proceeds. The sale of DENA s 50% ownership interest in Duke/UAE Ref-Fuel resulted in a gain of $178 million, which was recorded in Gains on Sales of Equity Investments in the Consolidated Statements of Operations.

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Impairment charges and net losses on sales, primarily related to the sale of Duke Energy Trading and Marketing, LLC (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 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 Statements of Operations, and gains of $32 million recorded in Gains on Sales of Equity Investments in the Consolidated Statements 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 Gains on Sales 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.

Sales of assets and businesses previously included in Other Operations 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 the 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 is a leading energy company located in the Americas with an affiliated real estate operation. Duke Energy provides its services through the business segments described below.

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 Public Service Commission of South Carolina (PSCSC).

Natural Gas Transmission provides transportation and storage of natural gas for customers throughout the East Coast and Southern U.S., the Pacific Northwest, and in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and gas transportation and processing services to customers in Western Canada. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission Corporation. Duke Energy Gas Transmission Corporation s natural gas transmission

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and storage operations in the U.S. are subject to the FERC s, the Texas Railroad Commission s, and the U.S. Department of Transportation s rules and regulations, while natural gas gathering, processing, transmission, distribution and storage operations in Canada are subject to the rules and regulations of the National Energy Board (NEB) or the Ontario Energy Board (OEB).

Field Services gathers, compresses, treats, processes, transports, trades and markets, and stores natural gas; and produces, transports, trades and markets, and stores natural gas liquids. It conducts operations primarily through DEFS, which is approximately 30% owned by ConocoPhillips and approximately 70% owned by Duke Energy. Field Services gathers natural gas from production wellheads in Western Canada and 10 states in the U.S. Those systems serve major natural gas-producing regions in the Western Canadian Sedimentary Basin, Rocky Mountain, Permian Basin, Mid-Continent and East Texas-Austin Chalk-North Louisiana areas, as well as onshore and offshore Gulf Coast areas.

DENA operates and manages merchant power generation facilities and engages in commodity sales and services related to natural gas and electric power around its generation assets and contractual positions. DENA conducts business throughout the U.S. and Canada generally through Duke Energy North America, LLC and DETM. DETM is 40% owned by Exxon Mobil Corporation and 60% owned by Duke Energy. In 2003, Duke Energy discontinued the proprietary trading business at DENA, commenced actions to unwind DETM, and announced its intent to reduce its investment in merchant power generation facilities by selling its facilities in the Southeast U.S. and reducing its interests in partially constructed facilities in the Western U.S.

International Energy develops, 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 and its activities target power generation in Latin America. During 2003, International Energy began the process to discontinue proprietary trading, and is in the process of exiting its European and Australian operations.

Beginning in 2004, Crescent, formerly part of Other Operations, is considered a separate reportable segment. All information for all the years presented within this report has been updated to show the impact of presenting Crescent as a separate reportable segment. Crescent develops high-quality commercial, residential and multi-family real estate projects, and manages legacy land holdings primarily in the Southeastern and Southwestern U.S.

All other entities previously included in Other Operations and now within Other still remain, primarily: DukeNet Communications, LLC (DukeNet), Duke Energy Merchants, LLC (DEM) and Duke/Fluor Daniel (D/FD). DukeNet develops and manages fiber optic communications systems for wireless, local and long-distance communications companies; and for selected educational, governmental, financial and health care entities. DEM is in the refined products business. During 2003, Duke Energy determined that it will exit the refined products business at DEM in an orderly manner and is unwinding its portfolio of contracts. D/FD provides comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide. D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation. During 2003, Duke Energy and Fluor Corporation announced that the D/FD partnership will be dissolved. The D/FD partners have adopted a plan for an orderly wind-down of the business targeted for completion in July 2005. Also previously included in Other Operations was Energy Delivery Services Inc., an engineering, construction, maintenance and technical services firm specializing in electric transmission and distribution lines and substation projects, until its sale on December 31, 2003. Additionally, Duke Capital Partners, LLC (DCP), a wholly owned merchant finance company that provided debt and equity capital and financial advisory services primarily to the merchant energy industry, had been previously included in Other Operations, but is now classified as discontinued operations.

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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

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 and 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 and cash equivalents are managed centrally by Duke Energy. Since the business units do not manage those items, the gains and losses on foreign currency remeasurement associated with cash balances, and third-party interest income on those balances, are generally excluded from the segments EBIT.

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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

Transactions between reportable segments are accounted for on the same basis as revenues and expenses in the accompanying Consolidated Financial Statements. The Other line item primarily includes certain unallocated corporate costs, and the elimination of intercompany profits. The table also provides information on segment assets, net of intercompany advances, intercompany notes receivable, intercompany current assets, intercompany derivative assets and investments in subsidiaries.

Business Segment Data(a)

	Unaffiliated Revenues	Intersegment Revenues	Total Revenues	Segment EBIT/ Consolidated (Loss) Earnings from Continuing Operations before Income Taxes	Depreciation and Amortization	Capital and Investment Expenditures	Segment Assets(b)
				(in millions)			
Year Ended December 31, 2003							
Franchised Electric	$ 4,862	$ 21	$ 4,883	$ 1,403	$ 748	$ 1,030	$ 16,088
Natural Gas Transmission	2,942	255	3,197	1,317	393	766	16,384
Field Services	7,987	674	8,661	186	299	211	6,417
Duke Energy North America	4,115	206	4,321	(3,341)	251	277	9,184
International Energy	597		597	210	57	71	4,550
Crescent (c)	284		284	133	7	290	1,653
Total reportable segments	20,787	1,156	21,943	(92)	1,755	2,645	54,276
Other	1,367	261	1,628	(272)	44	116	2,585
Eliminations		(1,417)	(1,417)	62			(658)
Interest expense				(1,380)			
Minority interest expense and other(d)				(36)			
Total consolidated	$ 22,154	$	$ 22,154	$ (1,718)	$ 1,799	$ 2,761	$ 56,203
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	4,875	1,115	5,990	149	286	309	6,793
Duke Energy North America	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	15,643	220	15,863	3,334	1,476	7,156	57,599
Other	133	170	303	(368)	35	193	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	$ 15,898	$	$ 15,898	$ 1,907	$ 1,511	$ 7,272	$ 60,122
Year Ended December 31, 2001							
Franchised Electric	$ 4,737	$ 9	$ 4,746	$ 1,626	$ 588	$ 1,115	$ 14,193
Natural Gas Transmission	922	138	1,060	607	141	748	5,047
Field Services	6,752	1,589	8,341	334	271	587	7,113
Duke Energy North America	4,562	(1,548)	3,014	1,487	103	3,213	14,107
International Energy	668	16	684	236	62	442	5,115
Crescent (c)	213		213	167	11	452	1,601
Total reportable segments	17,854	204	18,058	4,457	1,176	6,557	47,176
Other	92	505	597	(539)	82	483	3,294
Eliminations		(709)	(709)	230			(846)
Interest expense				(760)			
Minority interest expense and other(d)				(240)			
Cash acquired in acquisitions						(17)	
Total consolidated	$ 17,946	$	$ 17,946	$ 3,148	$ 1,258	$ 7,023	$ 49,624

(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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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

Geographic Data

	U.S.	Canada	Latin America	Other Foreign	Consolidated
			(in millions)		
2003					
Consolidated revenues	$ 16,617	$ 4,854	$ 556	$ 127	$ 22,154
Consolidated long-lived assets	35,220	9,272	2,449	1,589	48,530
2002					
Consolidated revenues	$ 13,850	$ 1,308	$ 674	$ 66	$ 15,898
Consolidated long-lived assets	38,138	7,895	2,118	2,234	50,385
2001					
Consolidated revenues	$ 15,668	$ 1,771	$ 197	$ 310	$ 17,946
Consolidated long-lived assets	35,494	516	2,573	1,594	40,177

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. (See Note 1.)

Duke Energy s Regulatory Assets and Liabilities

	December 31,	
Assets (Liabilities)	**2003**	**2002**
	(in millions)	
Net regulatory asset related to income taxes	$ 1,152	$ 936
Asset retirement obligation (ARO) costs(a)	547	
Deferred debt expense	169	174
Vacation accrual(a)	70	
U.S. Department of Energy (DOE) assessment fee(a)	33	44
Demand-side management costs(a)	18	38
Project costs(a)	17	20
Environmental cleanup costs(a)	8	10
Emission allowance control(a)	2	4
Removal costs(b)	(948)	

Nuclear decommissing costs(b)	(259)	
Other deferred tax credits(b)	(160)	(156)
Nuclear property and liability reserves(b)	(157)	(152)
North Carolina clean air compliance(b)	(95)	
South Carolina rate decrement	(23)	
Purchased capacity costs (see Note 5)(c)	(43)	151
Fuel cost liabilities(b)	(30)	(7)
Gas purchase costs(d)	(28)	44

(a) Included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets
(b) Included in Other Deferred Credits, Other Liabilities and Current Liabilities on the Consolidated Balance Sheets
(c) 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
(d) Included in Accounts Payable and Receivables on the Consolidated Balance Sheets

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

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.

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.

Removal Costs and Nuclear Decommissioning Costs. As a result of the adoption of SFAS No. 143 on January 1, 2003, approximately $1,207 million of removal costs and nuclear decommissioning costs at December 31, 2003 related to certain of Duke Energy s regulated operations have been classified as regulatory liabilities. See Note 7 for further discussion.

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 wholesale customers, excluding the other joint owners of the Catawba Nuclear Station: those rates are set through contractual agreements.

At December 31, 2003, Franchised Electric had recorded approximately $500 million in regulatory liabilities (net of regulatory assets). Management estimates that current rates are sufficient to recover these costs, 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 assets would be required to be recognized in current period earnings. 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.

Fuel costs are reviewed semiannually by the FERC and annually by the PSCSC, with provisions for reviewing those costs in base rates. The NCUC reviews 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 2002, the state of North Carolina passed clean air legislation that includes provisions that freeze 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 over the next ten years. Included in the legislation are provisions that allow electric utilities, including

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

Duke Energy, to accelerate the recovery of these compliance costs by amortizing them over seven years (2003-2009). Franchised Electric s amortization expense for 2003 included $115 million related to this clean air legislation. The legislation provides for significant flexibility in the amount of annual amortization recorded, allowing utilities to vary the amount amortized within certain limits although the legislation requires that a minimum of 70% of the total be amortized within the rate freeze period. In year 2003, amortization of compliance costs were approximately 54% of the annual levelized compliance costs.

In 2003, Duke Power reported to the PSCSC a 14.25% return on common equity, for the twelve month period ending March 31, 2003, for Duke Power s retail operations in South Carolina. In Duke Power s most recent base rate case proceeding, the PSCSC approved a rate of return on common equity range of 12.00% to 12.50% for Duke Power s South Carolina retail operations, with South Carolina retail rates based on 12.25%. In connection with the PSCSC s monitoring of the financial and operational condition of jurisdictional electric utilities, the PSCSC requested, and Duke Power provided, certain information relating to its reported returns on common equity. As a result, in September 2003, the PSCSC ordered Duke Power to implement a rate decrement of $30 million for South Carolina rates over the next twelve months (which took effect October 1, 2003 and expires September 30, 2004). The rate decrement was recorded in 2003 as an other liability (as it resulted from past bills paid by customers) and as a charge to revenues. Under this ruling, Duke Power was ordered in 2003 to write off to interest expense $16 million in deferred debt issuance costs that were previously capitalized as a regulatory asset.

Regional Transmission Organizations (RTOs). In 1999 and 2000, the FERC issued its Order 2000 and Order 2000-A regarding RTOs. These orders set minimum characteristics and functions RTOs must meet, including independent authority to establish the terms and conditions of transmission service over the facilities they control. The orders provide for an open and flexible RTO structure to meet the needs of the market and for the possibility of incentive ratemaking and other benefits for transmission owners that participate. The FERC proposes to have RTOs or other independent transmission providers operate transmission systems in all regions of the country.

As a result of these rulemakings, Duke Power and the franchised electric units of two other investor-owned utilities, Carolina Power & Light Company 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. The sponsors expected that GridSouth would be substantially operational by the FERC s Order 2000 deadline date of December 15, 2001. However, in July 2001 the FERC ordered GridSouth and other utilities in the Southeast to join in a mediation to negotiate terms of a southeastern RTO. It does not appear that the FERC will issue an order specifically based on that proceeding. In 2002, the GridSouth sponsors withdrew their applications to the NCUC and the PSCSC for approval of the transfer of functional control of their electric transmission assets to GridSouth, and announced that development of the GridSouth implementation project had been suspended until the sponsors have an opportunity to further consider regulatory circumstances. Duke Energy believes that more open wholesale electric markets will at some point provide benefits to consumers and other market participants. Duke Energy continues to examine options relative to RTOs in light of the existing complex regulatory environment. Management expects it will recover its investment in GridSouth.

Other Matters. As part of a fee in lieu of taxes agreement with Cherokee County, South Carolina, Duke Energy has agreed to transfer legal title of its Mill Creek combustion turbine facility located in Cherokee County, SC, to Cherokee County and then lease Mill Creek back from Cherokee County for approximately 20 years.

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Notes To Consolidated Financial Statements Continued

Under the lease agreement, Duke Energy will continue to operate Mill Creek as if it were the owner and will bear all costs of maintaining, operating and repairing Mill Creek. Duke Energy will retain the exclusive right to use Mill Creek. At the end of the twenty-year lease period, Cherokee County will transfer legal title of Mill Creek back to Duke Energy. The assets of Mill Creek will continue to be carried upon the books of Duke Energy as this transaction does not meet the qualifications for sale-leaseback accounting treatment.

On January 14, 2003, the PSCSC decided to conduct an independent management audit of Duke Power s preventive maintenance programs and service restoration procedures for its South Carolina retail electric service area in connection with a winter storm in December 2002. The PSCSC has contracted an independent firm to perform the management audit on its behalf. In late November 2003, the independent firm submitted its report to the PSCSC and in early December 2003, Duke Power submitted its response to issues raised by the report. Management believes that the final disposition of this matter will have no material adverse effect on consolidated results of operations, cash flows or financial position.

In 2001, the NCUC and the PSCSC began a joint investigation, along with the Public Staff of the NCUC, regarding certain Duke Power regulatory accounting entries for 1998, including the classification of nuclear insurance distributions. As part of their investigation, the NCUC and the PSCSC jointly engaged an independent firm to conduct an accounting investigation of Duke Power s accounting records for reporting periods from 1998 through June 30, 2001. In 2002 Duke Power entered into a settlement agreement with the NCUC and the PSCSC in which the parties agreed to changes in the accounting primarily related to nuclear insurance distributions, a one-time $25 million credit to Duke Power s deferred fuels account for the benefit of North Carolina and South Carolina customers, the reclassification of $50 million of a $58 million suspense account to a nuclear insurance operation reserve account and an additional $2 million adjustment to the nuclear insurance operation reserve account. The remaining $8 million in the suspense account was credited to income, resulting in a net $19 million pre-tax charge in 2002. A residential retail customer and the Carolina Utility Customers Association, Inc., (CUCA) a group that represents industrial customers in regulatory proceedings before the NCUC, appealed the decision related to the settlement agreement to the North Carolina Court of Appeals. On February 17, 2004, a panel of the North Carolina Court of Appeals unanimously affirmed the NCUC s decision. In addition, in February 2003, Duke Energy received a Western District of North Carolina Grand Jury subpoena for documents related to the audit by the NCUC and the PSCSC of Duke Power regarding certain Duke Power regulatory accounting entries from 1998 to 2000. On March 10, 2004, Duke Energy received notice from the U.S. Attorney for the Western District of North Carolina that its investigation had been closed and that no action against Duke Energy or any individuals was warranted.

In 2002, the NCUC issued an order denying a petition by CUCA to initiate a general rate proceeding and dismissing its complaint alleging unjust and unreasonable rates charged by Duke Power. CUCA appealed this order to the North Carolina Court of Appeals and on February 17, 2004, a panel of the Court unanimously ruled that the NCUC s denial of CUCA s petition and complaint was proper and therefore affirmed the NCUC s order.

Natural Gas Transmission. *Rate Related Information.* The British Columbia Pipeline System (BC Pipeline) and the field services business in western Canada have recorded approximately $543 million of regulatory assets related to deferred income tax liabilities. Under the current NEB-authorized rate structure, income tax costs are recovered in rates 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 rates 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.

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Notes To Consolidated Financial Statements Continued

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.

On December 1, 2003, BC Pipeline filed an application with the NEB for an order approving cost of service based tolls for 2004. It is not possible to predict at this time what the final result of those applications, including the impact on tolls and rates, will be.

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.

The process for OEB approval of Union Gas rates for 2004 is currently underway, with an OEB decision expected during the first quarter of 2004.

During 2002, Union Gas applied to the OEB for a change to the formula used to set the return on equity (ROE). In September 2003, the OEB consolidated this application with a similar application brought by Enbridge Gas Distribution. The proposed methodology had the effect of increasing the ROE awarded to Union Gas. In January 2004, the OEB issued its decision which reaffirmed the existing formula.

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. A March 2004 compliance deadline established by the OEB is expected to be extended to February 1, 2005. Union Gas has been granted leave to appeal the vendor consolidated billing provisions of GDAR by the Court of Appeal for Ontario.

In addition, 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 that 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 and these initiatives generally reflect more light-handed regulation of the natural gas industry.

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.

Notices of Proposed Rulemaking (NOPR). *NOPR on Standards of Conduct*. In November 2003, the FERC issued Order 2004, which harmonizes the standards of conduct applicable to natural gas pipelines and electric transmitting public utilities previously subject to differing standards. There remain two key issues regarding which Duke Energy has filed a formal request for clarification and rehearing with the FERC. The issues concern the Order s (i) restriction on how companies and their affiliates interact and share information, including corporate governance information, and (ii) expansion of coverage to affiliated gatherers, processors, and intrastate pipelines. A response to the request is anticipated in the second quarter of 2004. Full compliance with Order 2004 is required by June 1, 2004.

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Notes To Consolidated Financial Statements Continued

NOPR on Amendments to Blanket Sales Certificates and Order Proposing to Amend Market-Based Tariffs and Authorizations. In November 2003, the FERC issued two separate orders which condition market-based rate and blanket certificate authority on compliance with market behavior rules and codes of conduct addressing market manipulation, price reporting and record retention. Violation of the new conditions could result in disgorgement of unjust profits or suspension or revocation of a company s tariff or certificate. Duke Energy does not anticipate any significant financial impacts resulting from compliance with these new rules.

Final Rule on Cash Management Practices. In October 2003, the FERC issued a Final Rule implementing documentation and reporting requirements for FERC-regulated entities that participate in cash management programs. Management expects the Final Rule to have no material adverse effect on the consolidated results of operations, cash flows or financial position.

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, 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. Duke Energy s share of revenues and operating costs is included in the Consolidated Statements of Operations.

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 the cost of capacity purchased but not reflected in current rates is included in Other Current Assets, and Other Regulatory Assets and Deferred Debits. 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. Those net costs were $(43) million as of December 31, 2003 and $151 million as of December 31, 2002. Duke Energy expects to recover the remaining asset balance, including a return, during 2004. Duke Energy is currently reducing the liability amounts annually through a rate decrement.

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Notes To Consolidated Financial Statements Continued

6. Income Taxes

The following details the components of income tax (benefit) expense from continuing operations:

Income Tax (Benefit) Expense from Continuing Operations

	For the Years Ended December 31,		
	2003	2002	2001
		(in millions)	
Current income taxes			
Federal	$ (234)	$ 84	$ 822
State	(78)	14	106
Foreign	130	18	27
Total current income taxes	(182)	116	955
Deferred income taxes			
Federal	(472)	440	165
State	(9)	21	9
Foreign	(33)	48	33
Total deferred income taxes	(514)	509	207
Investment tax credit amortization	(13)	(14)	(13)
Total income tax (benefit) expense from continuing operations	$ (709)(a)	$ 611	$ 1,149(b)

(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.
(b) Excludes $59 million of deferred federal and state tax benefits related to the cumulative effect of change in accounting principle recorded net of tax.

The taxes recorded for discontinuing operations are excluded from the continuing operations section above and are presented as a separate column in Note 12.

(Loss) Earnings from Continuing Operations before Income Taxes

	For the Years Ended December 31,		
	2003	2002	2001
		(in millions)	
Domestic	$ (2,019)	$ 1,620	$ 2,929
Foreign	301	287	219
Total (loss) income	$ (1,718)	$ 1,907	$ 3,148

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Notes To Consolidated Financial Statements Continued

Income Tax (Benefit) Expense from Continuing Operations Reconciliation to Statutory Rate

	For the Years Ended December 31,		
	2003	2002	2001
		(in millions)	
Income tax (benefit) expense, computed at the statutory rate of 35%	$ (601)	$ 667	$ 1,102
State income tax, net of federal income tax effect	(57)	23	74
Tax differential on foreign earnings	(9)	(34)	(17)
Employee stock ownership plan dividends	(20)	(33)	(2)
Other items, net	(22)	(12)	(8)
Total income tax (benefit) expense from continuing operations	$ (709)	$ 611	$ 1,149
Effective tax rate	41.3%	32.0%	36.5%

Net Deferred Income Tax Liability Components

	December 31,	
	2003	2002
	(in millions)	
Deferred credits and other liabilities	$ 1,190	$ 1,540
Other	38	145
Total deferred income tax assets	1,228	1,685
Valuation allowance	(39)	(41)
Net deferred income tax assets	1,189	1,644
Investments and other assets	(985)	(1,043)
Accelerated depreciation rates	(3,006)	(4,224)
Regulatory assets and deferred debits	(1,059)	(856)
Total deferred income tax liabilities	(5,050)	(6,123)

Total net deferred income tax liabilities	$ (3,861)	$ (4,479)

The above amounts have been classified in the Consolidated Balance Sheets as follows:

Deferred Tax Liabilities

	December 31,	
	2003	**2002**
	(in millions)	
Current deferred tax assets, included in other current assets	$ 62	$ 59
Non-current deferred tax assets, included in other investments and other assets	197	296
Non-current deferred tax liabilities	(4,120)	(4,834)
Total net deferred income tax liabilities	$ (3,861)	$ (4,479)

Valuation allowances have been established for certain foreign 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 of the Reconciliation to Statutory Rate.

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Notes To Consolidated Financial Statements Continued

Deferred income taxes have not been provided on the 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, 2003, on which Duke Energy has not provided deferred income taxes, is approximately $630 million. During 2003 Duke Energy utilized certain losses that relate to the foreign currency adjustment in the amount of $114 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 and nuclear decommissioning 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 and nuclear decommissioning 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. The total amount of removal and nuclear decommissioning costs included as a liability in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets was $1,160 million as of December 31, 2002, which consisted of $1,139 million related to regulated electric operations and $21 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 and a regulatory liability 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.

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The following table shows the asset retirement obligation liability as though SFAS No. 143 had been in effect for the three prior years.

Pro forma Asset Retirement Obligation Liability

	(in millions)
January 1, 2001	$ 1,374
December 31, 2001	1,476
December 31, 2002	1,599

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 quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Asset Retirement Obligation Liability for the Year Ended December 31, 2003

	(in millions)
Balance as of January 1, 2003	$ 1,599
Liabilities settled	(7)
Accretion expense	111
Revisions in estimated cash flows	(2)
Foreign currency adjustment	6
Balance as of December 31, 2003	$ 1,707

Accretion expense for the year ended December 31, 2003 included approximately $106 million related to Duke Energy s regulated electric operations and has been deferred in accordance with SFAS No. 71 as discussed above. The fair value of assets legally restricted for the purpose of settling asset retirement obligations was $925 million as of December 31, 2003.

Nuclear Decommissioning Costs. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.9 billion in 1999 dollars, based on decommissioning studies completed in 1999 (studies are completed every five years). 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. 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.

The operating licenses for Duke Energy s nuclear units are subject to extension. In December 2003, Duke Energy was granted license renewals for the Catawba and McGuire Nuclear Stations. In 2000, Duke Energy was granted a license renewal for the Oconee Nuclear Station. The service period extension of the nuclear units will not impact depreciation or nuclear decommissioning rates unless justified by future depreciation and decommissioning studies, which will be filed with the NCUC and the PSCSC upon completion.

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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

During 2003, Duke Energy expensed approximately $56 million and contributed $56 million of cash to external funds for decommissioning costs (external reserve) and expensed an additional $11 million to the internal funds for decommissioning costs (internal reserve). During 2002, Duke Energy expensed approximately $59 million, and contributed $56 million of cash to the external reserve and expensed an additional $9 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 reserve was $925 million as of December 31, 2003 and $708 million as of December 31, 2002. These amounts are reflected in the Consolidated Balance Sheets as Nuclear Decommissioning Trust Funds (asset).

On February 5, 2004, the NCUC issued an order requiring Duke Energy to transition the internal reserve to the external reserve 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 externally.

The external reserve is invested primarily in domestic and international equity securities, fixed-rate, fixed-income securities and cash and cash equivalents and is recorded at its fair value in the Consolidated Balance Sheets. Per Nuclear Regulatory Commission (NRC), PSCSC, NCUC, 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. 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.

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 $118 million into the fund, including $11 million during 2003. The remaining liability and regulatory assets of $33 million as of December 31, 2003 and $44 million as of December 31, 2002 are reflected in the Consolidated Balance Sheets as Deferred Credits and Other

Liabilities, and Regulatory Assets and Deferred Debits.

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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 affiliates and businesses owned and operated in foreign countries. Duke Energy employs established policies 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, 2003

Asset/(Liability)	Maturity in 2004	Maturity in 2005	Maturity in 2006	Maturity in 2007 and Thereafter	Total Carrying Value
			(in millions)		
Hedging	$ 156	$ 26	$ 105	$ 137	$ 424
Trading	146	20	28	(17)	177
Undesignated	(19)	2	(44)	(154)	(215)
Total	$ 283	$ 48	$ 89	$ (34)	$ 386

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 $267 million as of December 31, 2003. 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.

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 18 years.

The ineffective portion of commodity cash flow hedges resulted in a gain of $5 million in 2003 and a loss of $8 million in 2002, net of taxes. The amount recognized for transactions that no longer qualified as cash flow hedges was a gain of $180 million, net of tax, in 2003 and was less than $1 million, net of tax, in 2002. The 2003 disqualified cash flow hedges were primarily associated with gas hedges of impaired DENA plants.

As of December 31, 2003, $88 million of after-tax deferred net gains on derivative instruments related to commodity cash flow hedges 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

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Notes To Consolidated Financial Statements Continued

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 2003 and 2002, the ineffective portion of commodity fair value hedges was not material. The amount recognized for transactions that no longer qualified as hedged firm commitments was a loss of $367 million, net of tax, in 2003 and was immaterial in 2002. The 2003 disqualified fair value hedges were associated with power hedges of impaired DENA 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 to the delivery of electricity over the next 12 years, are not included in the table above.

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 2003 and 2002.

Gains and losses deferred in anticipation of planned financing transactions on interest rate swap derivatives are included in AOCI and amortized over the life of the underlying debt once issued. These deferred gains and losses were not material in 2003 or 2002.

Foreign Currency (Fair Value, Net Investment or Cash Flow) Hedges. Duke Energy is exposed to foreign currency risk from investments in international affiliates and businesses owned and operated in foreign countries. 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. At December 31, 2003, $113 million of net losses were included in the cumulative translation adjustment for hedges of net investments in foreign operations. At December 31, 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 discontinued proprietary trading and therefore the fair value of trading contracts as of December 31, 2003 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.

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Notes To Consolidated Financial Statements Continued

Changes in Fair Value of Duke Energy s Trading Contracts During 2003

	(in millions)
Fair value of contracts outstanding at the beginning of the year	$ 489
Amounts reclassified to cumulative effect of change in accounting principle and re-characterized as undesignated as discussed below(a)	(288)
Contracts realized or otherwise settled during the year	(8)
Net premiums received for new option contracts during the period	(13)
Other changes in fair values	(3)
Fair value of contracts outstanding at the end of the year	$ 177

(a) Amount represents $294 million in fair value of energy-related (non-derivative) contracts as of January 1, 2003 which were charged to cumulative effect of change in accounting principle on the Consolidated Statements of Operations. This is partially off-set by $6 million in identified contracts re-characterized as undesignated as a result of implementing the remaining provisions of EITF Issue No. 02-03.

Fair Value of Duke Energy s Trading Contracts as of December 31, 2003

Asset/(Liability) Sources of Fair Value	Maturity in 2004	Maturity in 2005	Maturity in 2006	Maturity in 2007 and thereafter	Total Fair Value
			(in millions)		
Prices supported by quoted market prices and other external sources	$ 155	$ (2)	$ 24	$ (22)	$ 155
Prices based on models and other valuation methods	(9)	22	4	5	22
Total	$ 146	$ 20	$ 28	$ (17)	$ 177

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 and crude oil. The NYMEX has currently quoted prices for the next 54 months. In addition, this category includes Duke Energy s forward positions and options in natural gas and power and natural gas basis swaps at points for which over-the-counter (OTC) broker quotes are available. On average, OTC quotes for natural gas and power forwards and swaps extend 42 and 48 months into the future, respectively. OTC quotes for natural gas and power options extend 12 months into the future, on average. Duke Energy values these positions using internally developed forward market price curves that are constantly updated to conform with 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

DUKE ENERGY CORPORATION

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January 2003, all of the contracts in the prices based on models and other valuation methods category as of December 31, 2003 are derivatives as defined by SFAS No. 133.

Proprietary trading exposes Duke Energy to a variety of market risks. Validation of a contract s fair value is performed by the Risk Management Group, 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.

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.

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, Asia Pacific 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 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. 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 NYMEX-traded futures and options contracts requires daily cash settlement in margin accounts with brokers.

Duke Energy s claims made in the Enron Corporation (Enron) bankruptcy case exceeded its non-collateralized accounting exposure. Bankruptcy claims that exceed this amount primarily relate to termination and settlement rights under normal purchases and normal sales contracts where Enron was the counterparty. (See Note 17)

Substantially all contracts with Enron were completed or terminated prior to December 31, 2001. Duke Energy has continuing contractual relationships with certain Enron affiliates, which are not in bankruptcy. In

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Brazil, a power purchase agreement between a Duke Energy affiliate, Companhia de Geracao de Energia Electrica Paranapanema (Paranapanema), and Elektro Eletricidade e Servicos S/A (Elektro), a distribution company approximately 100% owned by Enron, will expire December 31, 2005. The contract was executed by Duke Energy s predecessor in interest in Paranapanema, and obligates Paranapanema to provide energy to Elektro on an irrevocable basis for the contract period.

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, 2003 and 2002, are not necessarily indicative of the amounts Duke Energy could have realized in current markets.

Financial Instruments

	2003		2002	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Long-term debt(a)	$ 21,822	$ 23,554	$ 21,550	$ 22,693
Guaranteed preferred beneficial interests in subordinated notes of Duke Energy or subsidiaries			1,408	1,466
Preferred stock(b)	134	135	159	155

(a) Includes current maturities
(b) Includes current maturities in 2002

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. 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, Duke Energy recorded a $254 million goodwill impairment charge in the third quarter 2003 to write off all DENA goodwill, most of which related to DENA s trading and marketing business. This impairment charge reflects 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 marketing business, a portion 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

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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 12 for further information regarding the European reporting unit and its treatment as discontinued operations in the Consolidated Statements of Operations.

Changes in the Carrying Amount of Goodwill

	Balance December 31, 2002	Acquired Goodwill	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
Duke Energy North America	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

	Balance December 31, 2001	Acquired Goodwill	Impairments	Dispositions	Other(a)	Balance December 31, 2002
Natural Gas Transmission	$ 481	$ 2,279	$	$	$	$ 2,760
Field Services	571				(90)	481
Duke Energy North America	91				9	100
International Energy	427	18	(194)		(5)	246
Crescent					6	6
Other(b)	160				(6)	154
Total consolidated	$ 1,730	$ 2,297	$ (194)	$	$ (86)	$ 3,747

(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.

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The following table shows what earnings available for common stockholders and earnings per share would have been if amortization (including any related tax effects) related to goodwill that is no longer being amortized (effective January 1, 2002) had been excluded from the year ended December 31, 2001.

Goodwill Adoption of SFAS No. 142

	For the year ended December 31, 2001 (in millions, except per share amounts)
Earnings available for common stockholders	
Reported earnings available for common stockholders	$ 1,884
Add back: Goodwill amortization, net of tax	75
Adjusted earnings available for common stockholders	$ 1,959
Basic earnings per share	
Reported earnings per share	$ 2.45
Goodwill amortization	0.10
Adjusted earnings per share	$ 2.55
Diluted earnings per share	
Reported earnings per share	$ 2.44
Goodwill amortization	0.10
Adjusted earnings per share	$ 2.54

10. 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 $263 million in 2003, $369 million in 2002 and $158 million in 2001 from those investments. Duke Energy s share of net income from these unconsolidated affiliates is reflected in the Consolidated Statements of Operations as Equity in Earnings of Unconsolidated Affiliates. (See Note 2 for 2003 dispositions.)

As of December 31, 2003 investments in affiliates were carried at approximately $66 million less than the amount of underlying equity in net assets (5% of total investment in affiliates 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.

As of December 31, 2002 investments in affiliates were carried at approximately $330 million less than the amount of underlying equity in net assets (16% of total investment in affiliates as of December 31, 2002). Approximately $146 million related to recording investments acquired as part of the Westcoast acquisition at fair value. These assets were sold in 2003. Approximately $161 million 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.

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Natural Gas Transmission. As of December 31, 2003 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.

Field Services. As of December 31, 2003 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.

Duke Energy North America. As of December 31, 2003 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.

International Energy. As of December 31, 2003 significant investments 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.

Crescent. As of December 31, 2003 investments included various real estate development projects.

Other. As of December 31, 2003 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, 2003			December 31, 2002		
	Domestic	International	Total	Domestic	International	Total
	(in millions)					
Natural Gas Transmission	$ 787	$ 5	$ 792	$ 1,044	$ 191	$ 1,235
Field Services	194		194	239		239
Duke Energy North America	139	39	178	296	43	339

International Energy		147	147		122	122
Crescent	15		15	17		17
Other	66	6	72	58	5	63
Total	$ 1,201	$ 197	$ 1,398	$ 1,654	$ 361	$ 2,015

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Equity in Earnings of Unconsolidated Affiliates

	For the years ended:								
	December 31, 2003			December 31, 2002			December 31, 2001		
	Domestic	International	Total	Domestic	International	Total	Domestic	International	Total
	(in millions)								
Natural Gas Transmission	$ 19	$ 8	$ 27	$ 87	$ 19	$ 106	$ 38	$ 7	$ 45
Field Services	56		56	60		60	45		45
Duke Energy North America	22	(2)	20	39	5	44	54		54
International Energy		27	27		63	63		35	35
Crescent							2		2
Other (a)	(9)	2	(7)	(54)	(1)	(55)	(17)		(17)
Total	$ 88	$ 35	$ 123	$ 132	$ 86	$ 218	$ 122	$ 42	$ 164

(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.

Summarized Combined Financial Information of Unconsolidated Affiliates

	As of December 31,	
	2003	2002
	(in millions)	
Balance Sheet		
Current assets	$ 1,552	$ 2,233
Noncurrent assets	8,435	14,865
Current liabilities	(979)	(1,711)
Noncurrent liabilities	(4,062)	(8,665)
Net assets	$ 4,946	$ 6,722

	For the Years Ended December 31,		
	2003	2002	2001
Income Statement			
Operating revenues	$ 6,253	$ 6,072	$ 5,177
Operating expenses	5,526	5,094	4,525
Net income	550	830	475

Related Party Transactions. Outstanding notes receivable from unconsolidated affiliates were $146 million as of December 31, 2003 and $113 million as of December 31, 2002. Of the notes outstanding as of December 31, 2003, $128 million related to notes from partners in two projects in which International Energy had 30% and 50% ownership and the majority of the remaining $18 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.

In 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.

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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

In 2003, Natural Gas Transmission sold its ownership interest in Alliance Pipeline and Vector Pipeline. However, Natural Gas Transmission has certain commitments to pay for firm capacity on these pipelines. Payments for the year ended December 31, 2003 were $33 million and $30 million for the year ended December 31, 2002.

Subsidiaries of Duke Energy and Fluor Corporation formed the D/FD 50/50 partnership in 1989. The partnership provides full-service siting, permitting, licensing, engineering, procurement, construction, start-up, operating and maintenance services for fossil-fueled plants in the U.S. and internationally. D/FD was the primary builder of DENA s merchant generation plants. D/FD has built and provides support for 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, 2003, Duke Energy deferred profit of $59 million for D/FD 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. For the year ended December 31, 2001, Duke Energy deferred profit of $54 million for construction contracts and eliminated profit of $9 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 14). During 2003, Duke Energy and Fluor Corporation announced that the D/FD partnership between subsidiaries of the two companies will be dissolved. The D/FD partners have adopted a plan for an orderly wind-down of the business targeted for completion in July 2005.

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 it were transacted with a third party and records the contract using mark-to-market or accrual accounting, 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 14, Debt and Credit Facilities, Note 17, Commitments and Contingencies, and Note 18, Guarantees and Indemnifications, for additional related party information.

11. Impairment and Other Related Charges

Impairment and Other Related Charges

	For the Years Ended December 31,

	2003	2002
	(in millions)	
Duke Energy North America	$ 2,903	$ 207
Field Services		78
International Energy		75
Other	53	4
Total impairment and other related charges	$ 2,956	$ 364

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

Duke Energy did not have any impairment and other related charges for 2001.

Duke Energy North America. During the past two years, the merchant energy industry in the U.S. suffered from oversupply of merchant generation, low commodity pricing and volatility, and a steep decline in trading and marketing activity. These market conditions are expected to continue for several years. As a result of these market conditions, Duke Energy made decisions in 2003 and 2002 that caused Duke Energy to evaluate the carrying values of certain long-lived assets at DENA.

In the fourth quarter of 2003, Duke Energy decided to exit the merchant power generation business in the Southeastern U.S. and intends to sell DENA s eight plants in this region. The carrying value of these assets exceeded the fair value, resulting in an impairment charge in 2003. The fair value of the Southeastern U.S. power generation assets was estimated primarily based on third party comparable sales, analysis from outside advisors and information available from efforts to sell certain of these assets.

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). Duke Energy intends to either sell the deferred plants as is, complete construction of the plants in conjunction with a partner, or identify an alternative use for the facilities. The carrying value of these assets exceeded the fair value, resulting in an impairment charge in 2003. 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.

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 was recorded in 2003. Subsequently, the anticipated transaction did not occur, and management decided not to sell the plant, thus removing the asset from held for sale.

Duke Energy recorded additional impairment charges in 2003, primarily associated with a change in the expected dispatch of a plant in California and a plan to sell an investment in an unconsolidated affiliate. Fair value of these assets was estimated based primarily on discounted cash flow analysis.

Certain forward power contracts related to the power generation assets in the Southeastern U.S. 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 of these decisions, Duke Energy recorded impairment charges in 2003 of $2,903 million, 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. These impairments were primarily related to electric generation plants which are classified as Property, Plant and Equipment on the Consolidated Balance Sheets. Fair value of these assets was estimated based on comparable sales or discounted cash flow analysis.

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Notes To Consolidated Financial Statements   Continued

Field Services. The 2002 charges were primarily to write-off inventory and other current assets to their net realizable value.

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.

12. Assets Held for Sale and Discontinued Operations

During 2003, Duke Energy began activities to sell certain long-lived assets or businesses, which are classified as Assets Held for Sale on the Consolidated Balance Sheets as of December 31, 2003 in accordance with SFAS No. 144.

As a result of the continued decline in the merchant energy industry, during 2003 Duke Energy decided to sell certain turbines and related equipment owned by DENA. In connection with the sales plan, a loss of $66 million was recorded, which represents the excess of the carrying value over the estimated fair value of the turbines and related equipment, less estimated costs to sell, and was included in (Losses) Gains on Sales of Other Assets, net in the Consolidated Statements of Operations. Fair value of the turbines was based primarily on comparable third party sales. (See Note 23.)

In order to eliminate exposure to international markets outside of Latin America and Canada, in 2003 Duke Energy decided to pursue a possible sale or initial public offering of International Energy s Asia-Pacific power generation and natural gas transmission business. This business is expected to be sold within twelve months. As a result of this decision, International Energy recorded a pre-tax loss, which represents 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 loss was included in Discontinued Operations Net Loss on Dispositions in the Consolidated Statements of Operations.

Additionally in 2003, International Energy restructured and began exiting its operations in Europe. This business is expected to be sold over the next twelve months. Also in 2003, International Energy sold its Dutch gas marketing business for $84 million and sold a power generation plant in France for $79 million. Duke Energy recorded a pre-tax net gain on these sales, which was included in Discontinued Operations Net Loss on Dispositions in the Consolidated Statements of Operations. An income tax benefit was recorded in 2003, primarily associated with the 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 Loss on Dispositions in the Consolidated Statements of Operations.

During 2003, Duke Energy decided to exit the merchant finance business conducted by DCP. As a result, Duke Energy recorded a pre-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, the primary component of the business, was estimated based primarily on discounted cash flow analysis. The loss was included in Discontinued Operations Net Loss on Dispositions, in the Consolidated Statements of Operations. Duke Energy expects that the exit of the merchant finance business will occur within twelve months.

Crescent routinely develops real estate projects and operates those facilities until they are substantially leased and a sales agreement is finalized. If a project has distinguishable operations and cash flows and Crescent

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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

does not retain any continuing involvement in the project after it is sold and cash flows of the sold projects have been eliminated from Crescent s ongoing operations, SFAS No. 144 requires these real estate projects be classified as discontinued operations. During 2003, Crescent sold three retail centers and one apartment complex, all located in Florida, for a total sales price of approximately $77 million. The pre-tax gain on these sales was included in Discontinued Operations Net Loss on Dispositions, in the Consolidated Statements of Operations.

Negotiations for dispositions or transfers of some of these assets are at various stages with prospective buyers. In the event that Duke Energy agrees to dispose of assets at prices less than their December 31, 2003 carrying value, additional losses would be recorded.

The following table presents the carrying amount as of December 31, 2003 of the major classes of assets and liabilities held for sale in the Consolidated Balance Sheets. These assets and liabilities are intended to be either disposed of or transferred in the sales transactions.

Summarized Balance Sheet Information for Assets Held for Sale

	(in millions)
Current assets	$ 424
Investments and other assets	379
Property, plant and equipment, net	1,065
Total assets held for sale	$ 1,868
Current liabilities	$ 651
Long-term debt	514
Deferred credits and other liabilities	223
Total liabilities associated with assets held for sale	$ 1,388

Additionally in 2003 Duke Energy initiated efforts to focus on its core energy business, exiting businesses not considered strategic. The following operations were discontinued and sold in 2003.

DEFS sold two packages of assets for a total sales price of $90 million. The gain on these sales was included in Discontinued Operations Net Loss on Dispositions 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.

DEM sold Duke Energy Hydrocarbons LLC for approximately $83 million. Duke Energy recorded a loss on the sale, which was included in Discontinued Operations Net Loss on Dispositions, in the Consolidated Statements of Operations.

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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. Duke Energy recorded a loss on the sale, which was included in Discontinued Operations Net Loss on Dispositions in the Consolidated Statements of Operations. In addition, in the first quarter of 2004, DEFS sold assets in West Texas for approximately $62 million. The table below has been updated to reflect the related operations as discontinued for the years ended December 31, 2003, 2002 and 2001.

Discontinued Operations

		Operating Loss			Loss on Disposition		
	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
				(in millions)			
Year Ended December 31, 2003							
Field Services	$ 279	$ 9	$ 4	$ 5	$ 18	$ 7	$ 11
International Energy	759	(29)	(4)	(25)	(242)	(119)	(123)
Crescent	5	1	1		18	7	11
Other	30	(4)	(1)	(3)	(46)	(18)	(28)
Total consolidated	$ 1,073	$ (23)	$	$ (23)	$ (252)	$ (123)	$ (129)
Year Ended December 31, 2002							
Field Services	$ 261	$ (24)	$ (9)	$ (15)	$	$	$
International Energy	133	(256)	7	(263)			
Other	57	25	9	16			
Total consolidated	$ 451	$ (255)	$ 7	$ (262)	$	$	$
Year Ended December 31, 2001							
Field Services	$ 331	$ 1	$ 1	$	$	$	$
International Energy	107	(18)	(3)	(15)			
Other	74	13	3	10			
Total consolidated	$ 512	$ (4)	$ 1	$ (5)	$	$	$

The 2002 discontinued operations pre-tax operating income (loss) for International Energy included a goodwill impairment loss of $194 million, which was not deductible for tax purposes until 2003 when the business was restructured.

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Notes To Consolidated Financial Statements   Continued

13. Property, Plant and Equipment

	December 31,	
	2003	2002
	(in millions)	
Land(a)	$ 503	$ 391
Plant		
Electric generation, distribution and transmission(a)	23,577	23,360
Natural gas transmission and distribution	11,536	10,801
Gathering and processing facilities(a)	5,435	5,167
Other buildings and improvements(a)	448	540
Nuclear fuel	863	827
Equipment	1,166	1,057
Vehicles	135	168
Construction in process(b)	1,029	3,624
Other(a)	1,317	1,433
Total property, plant and equipment	46,009	47,368
Total accumulated depreciation(c), (d)	(12,139)	(11,266)
Total net property, plant and equipment	$ 33,870	$ 36,102

(a) Includes capitalized leases: $293 million for 2003 and $425 million for 2002.
(b) Includes $49 million as of December 31, 2003 and $1,165 million as of December 31, 2002 related to DENA merchant power plants for which construction has been deferred. The majority of deferred merchant plant costs were written down in 2003 due to impairment. (See Note 11 for additional information on impairment and other related charges.)
(c) Includes accumulated amortization of nuclear fuel: $604 million for 2003 and $566 million for 2002.
(d) Includes accumulated amortization of capitalized leases: $87 million for 2003 and $139 million for 2002.

Capitalized interest of $132 million for 2003, $250 million for 2002 and $167 million for 2001 is included in the Consolidated Statements of Operations.

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14. Debt and Credit Facilities

Summary of Debt and Related Terms

	Weighted-Average Rate	Year Due		December 31, 2003	December 31, 2002
		(in millions)			
Unsecured debt	6.5%	2004	2038	$ 16,562	$ 16,222
Secured debt	2.8%	2004	2019	2,344	2,654
First and refunding mortgage bonds	4.6%	2008	2027	1,215	690
Trust preferred securities(a)	7.5%	2029	2039	876	
Capital leases	8.9%	2005	2032	367	339
Other debt(b)	2.0%	2004	2017	309	514
Commercial paper(c)	1.3%			240	2,030
Preferred stock with sinking fund requirements(d)	6.8%	2004	2015	25	
Fair value hedge carrying value adjustment		2004	2032	95	123
Unamortized debt discount and premium, net				(81)	(107)
Total debt(e), (f)				21,952	22,465
Current maturities of long-term debt				(1,200)	(1,329)
Short-term notes payable and commercial paper(g)				(130)	(915)
Total long-term debt				$ 20,622	$ 20,221

(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.

(b) Includes $172 million of Duke Energy pollution control bonds as of December 31, 2003 and 2002. As of December 31, 2003, $40 million was secured by first and refunding mortgage bonds and $77 million was secured by a letter of credit, and as of December 31, 2002, $117 million was secured by first and refunding mortgage bonds.

(c) Includes $150 million as of December 31, 2003 and $1,150 million as of December 31, 2002 that was classified as Long-term Debt on the Consolidated Balance Sheets. The weighted-average days to maturity were 18 days as of December 31, 2003 and 20 days as of December 31, 2002.

(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, 2003, $437 million of debt was denominated in Brazilian reais with the principal indexed annually to Brazilian inflation and $3,673 million of debt was denominated in Canadian dollars. As of December 31, 2002, $675 million of debt was denominated in Australian dollars, $346 million of debt was denominated in Brazilian reais with the principal indexed annually to Brazilian inflation and $3,462 million of debt was denominated in Canadian dollars.

(f) Excludes $883 million of long-term debt, notes payable and commercial paper denominated in Australian dollars related to International Energy s Australian operations. As of December 31, 2003, International Energy s Australian operations were classified as discontinued operations, and the debt associated with the Australian operations was reclassified to Current and Non-Current Liabilities Associated with Assets Held for Sale as the debt is intended to be transferred in the sale transaction and subsequently retired.

(g) Weighted-average rates on outstanding short-term notes payable and commercial paper was 1.7% as of December 31, 2003 and 2.6% as of December 31, 2002.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

Floating Rate Debt. Unsecured debt, secured debt and other debt included $2,717 million of floating-rate debt as of December 31, 2003, and $3,545 million as of December 31, 2002. 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, 2003, the average interest rate associated with floating-rate debt was 1.8%.

Convertible Debt. As of December 31, 2003, 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 holders put the senior notes back to Duke Energy, 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, 2003. Therefore, the contingently issuable shares of common stock were not included in the calculation of diluted earnings per share for the year ended December 31, 2003. 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.

Additionally, as of December 31, 2003 and 2002, unsecured debt included $1,625 million of Equity Units. The Equity Units consist of senior notes of Duke Capital, and forward purchase contracts obligating the investors to purchase shares of Duke Energy s common stock in 2004. The number of shares of common stock to be issued in 2004 will be based on the price of the common stock at the date of maturity of the forward purchase contract. Based upon the price of the common stock on December 31, 2003, the forward purchase contracts to be settled in May 2004 and November 2004 will result in the issuance of approximately 22.5 million shares of common stock and 18.7 million shares of common stock, respectively. The issuable shares of common stock under the forward purchase contracts were not included in the calculation of diluted earnings per share for the year ended December 31, 2003 as their effect was antidilutive.

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 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, 2003, the interest rate associated with the credit facility, which is based on commercial paper rates, was 1.5% 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

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

of Financial Assets and Extinguishments of Liabilities, and accordingly is reflected as a secured borrowing in the Consolidated Financial Statements. As of December 31, 2003, the $300 million outstanding balance of the credit facility was secured by approximately $446 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, 2003, secured debt also consisted of various project financings, including THOR Investors, LLC, Maritimes & Northeast Pipeline, LLC, Maritimes & Northeast Pipeline, LP 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, 2003, substantially all of Franchised Electric s electric plant in service was subject to a mortgage lien securing the first and refunding mortgage bonds.

Related Party Debt. Other debt included $78 million related to a loan with D/FD as of December 31, 2003, and $282 million as of December 31, 2002. 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 1.52% as of December 31, 2003 and 2.50% as of December 31, 2002. During 2003, Duke Energy and Fluor Corporation announced that the D/FD partnership will be dissolved. The D/FD partners have adopted a plan for an orderly wind-down of the business targeted for completion in July 2005. The entire outstanding balance of the loan with D/FD has been classified as Current Maturities of Long-term Debt and Preferred Stock on the December 31, 2003 Consolidated Balance Sheet.

Additionally, 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. Duke Energy has the option to repay this debt to affiliates early, and could potentially repay all of this debt to affiliates in 2004.

Maturities, Call Options and Acceleration Clauses.

Annual Maturities as of December 31, 2003

	(in millions)
2004	$ 1,200
2005	2,961
2006	2,531
2007	718
2008	1,172

Thereafter	13,240
Total long-term debt(a)	$ 21,822

(a) Excludes short-term notes payable and commercial paper of $130 million.

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Notes To Consolidated Financial Statements Continued

Annual maturities after 2008 include $1,400 million of long-term debt with call options, which provide Duke Energy with the option to repay the debt early. Based on the years in which Duke Energy may first exercise its redemption options, it could potentially repay $1,050 million in 2004, $100 million in 2005, and $250 million in 2006.

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, 2003, Duke Energy had $19 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 $30 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.

Subsequent Debt Issuances and Redemptions. In February 2004, Duke Capital remarketed $875 million of its 5.87% senior notes due in 2006. As a result of the remarketing, the interest rate on the notes was reset to 4.302%. The remarketing was required under the terms of the Equity Units originally issued in March 2001. Proceeds from the remarketed senior notes were used to purchase U.S. Treasury securities being held by a collateral agent to satisfy the forward stock purchase contracts component of the Equity Units. In May 2004, Duke Energy intends to receive $875 million from the collateral agent, and to issue approximately 22.5 million shares of Duke Energy common stock pursuant to the forward stock purchase contracts. Additionally, in February 2004, Duke Capital issued $200 million of 4.37% senior unsecured notes due in 2009 and $288 million of 5.50% senior unsecured notes due in 2014 in exchange for $475 million of the principle amount of remarketed senior notes. After the exchange, $400 million of the principal amount of the remarketed senior notes remained outstanding.

Also, in February 2004, Duke Energy announced that on March 26, 2004, it will redeem the entire issue of 7.20% Duke Energy debt to an affiliate due in 2037. The redemption price will be approximately $360 million, and the redemption is not anticipated to have a material impact on Duke Energy s Consolidated Statements of Operations.

For additional information on subsequent debt issuances and redemptions see Note 23.

Available Credit Facilities and Restrictive Debt Covenants. During 2003, Duke Energy, Duke Capital, Westcoast, Union Gas, DEFS and Duke Australia Finance Pty Ltd. (a wholly owned subsidiary of Duke Energy) replaced portions of their expiring credit facilities, thereby reducing the total amount of credit facilities available by approximately $2.2 billion. The credit facilities that have replaced the expired credit facilities are included in the following table which summarizes Duke Energy s credit facilities and related amounts outstanding as of December 31, 2003. The majority of the credit facilities support commercial paper programs. 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 acceleration of due dates of certain borrowings and/or termination of the agreements. As of December 31, 2003, Duke Energy was in compliance with those covenants. In addition, certain of the credit agreements contain cross-acceleration provisions that may allow for acceleration of payments or termination of the agreements upon: (1) nonpayment or (2) acceleration of other significant indebtedness of the applicable borrower or certain of its subsidiaries. None of the credit agreements contain material adverse change clauses or any covenants based upon credit ratings.

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Credit Facilities Summary as of December 31, 2003

	Expiration Date	Credit Facilities Available	Amounts Outstanding: Commercial Paper	Letters of Credit	Other Borrowings	Total
			(in millions)			
Duke Energy						
$125 364-day bilateral (a), (b)	August 2004					
$475 multi-year syndicated (a), (b)	August 2004					
$150 two-year bilateral (a), (b)	September 2005					
Total Duke Energy		$ 750	$ 228	$	$	$ 228
Duke Capital LLC						
$252 364-day syndicated letter of credit (a), (b), (c)	April 2004					
$538 multi-year syndicated letter of credit (b), (c)	April 2004					
$550 multi-year syndicated (a), (b), (c)	August 2004					
Total Duke Capital LLC		1,340		483		483
Westcoast Energy Inc.						
$155 364-day syndicated (a), (b), (d)	July 2004					
$77 two-year syndicated (b), (e)	July 2005					
Total Westcoast Energy Inc.		232	12			12
Union Gas Limited						
$263 364-day syndicated (a), (f)	July 2004	263				
Duke Energy Field Services, LLC						
$350 364-day syndicated (a), (c), (g)	March 2004	350				
Duke Australia Finance Pty Ltd.						
$237 364-day syndicated (c), (h), (i)	March 2004	237	135			135
Duke Australia Pipeline Finance Pty Ltd.						
$234 multi-year syndicated (i), (j)	February 2005	234			212	212
Total (k)		$ 3,406	$ 375	$ 483	$ 212	$ 1,070

(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 200 million Canadian dollars as of December 31, 2003.
(e) Credit facility is denominated in Canadian dollars, and was 100 million Canadian dollars as of December 31, 2003.
(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 340 million Canadian dollars as of December 31, 2003.
(g) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 53%.
(h) Credit facility is guaranteed by Duke Capital, is denominated in Australian dollars, and was 316 million Australian dollars as of December 31, 2003.
(i) Credit facility pertains to operations that are classified as discontinued operations as of December 31, 2003. Therefore, the outstanding debt associated with the credit facility was reclassified to Current and Non-Current Liabilities Associated with Assets Held for Sale on the

December 31, 2003 Consolidated Balance Sheet.

(j) Credit facility is guaranteed by Duke Capital, is denominated in Australian dollars, and totaled 312 million Australian dollars as of December 31, 2003. Duke Australia Pipeline Finance Pty Ltd. is a wholly owned subsidiary of Duke Energy.

(k) Various operating credit facilities and credit facilities that support commodity, foreign exchange, derivative and intra-day transactions are not included in this credit facilities summary.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

Duke Energy has approximately $2,900 million of credit facilities which expire in 2004. It is Duke Energy s intent to resyndicate less than the total $2,900 million of expiring credit facilities.

Other Loans. During 2003 and 2002, 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 $467 million as of December 31, 2003 and $428 million as of December 31, 2002. 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.

15. Guaranteed Preferred Beneficial Interests in Subordinated Notes of Duke Energy or Subsidiaries

Duke Energy and Duke Capital have formed trust subsidiaries for which they own all the common securities. The trust subsidiaries issue and sell preferred securities and invest the gross proceeds in junior subordinated notes issued by the respective parent companies. The trust subsidiaries are wholly owned financing subsidiaries of Duke Energy and Duke Capital, and the respective parent company that issued the debt held by each trust subsidiary has fully and unconditionally guaranteed payment of the preferred securities to preferred note holders. Payment under the guarantee is made only to the extent that the trust subsidiary has legally and immediately available funds for distribution.

Upon the implementation of SFAS No. 150, effective July 1, 2003, as discussed in Note 1, the Guaranteed Preferred Beneficial Interests in Subordinated Notes of Duke Energy Corporation or Subsidiaries were reclassified to Long-term Debt and the related unamortized debt discount was reclassified to Deferred Debt Expense on the Consolidated Balance Sheets. The trust preferred securities are mandatorily redeemable financial instruments under the provisions of SFAS No. 150, since the trust preferred securities are redeemable in cash, at par value, on or prior to a specified maturity date, ranging from 2029 to 2039. In addition, Duke Energy has the option to redeem these financial instruments before their maturity date any time after five years from the date of issuance, or upon the occurrence of certain contingent events. Also, effective July 1, 2003, in accordance with the provisions of SFAS No. 150, the amortization of related debt issue costs and interest payments associated with the trust preferred securities have been classified on the Consolidated Statements of Operations as Interest Expense rather than Minority Interest Expense. In accordance with the requirements of SFAS No. 150, prior period amounts were not reclassified.

In June 2003, prior to the implementation of SFAS No. 150, Duke Capital redeemed $250 million of its 7.375% trust preferred securities due in 2038. An approximate loss of $8 million on the early extinguishment of the trust preferred securities was recorded as Dividends and Premiums on Redemption of Preferred and Preference Stock in the Consolidated Statements of Operations. In December 2003, subsequent to the implementation of SFAS No. 150, Duke Capital redeemed $350 million of its 7.375% trust preferred securities due in 2038. An approximate loss of $10 million on the early extinguishment of the trust preferred securities was recorded as Interest Expense in the Consolidated Statements of Operations.

Additionally, 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. Consistent with SFAS No. 150, beginning January 1, 2004, the amortization of related debt issue costs and interest payments associated with the trust preferred securities will be classified on the Consolidated Statements of Operations as Interest Expense rather than Minority Interest Expense. As permitted by FIN 46R, prior period amounts have not been reclassified.

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The following table details the Guaranteed Preferred Beneficial Interests in Subordinated Notes of Duke Energy Corporation or Subsidiaries as of the December 31, 2002 Consolidated Balance Sheet. See Note 14 for details on the December 31, 2003 outstanding balance of the debt to affiliates related to the trust preferred securities.

Trust Preferred Securities

Issued	Rate	Due	December 31, 2002
			(in millions)
1997	7.20%	2037	$ 350
1998	7.375%	2038	350
1998	7.375%	2038	250
1999	8.375%	2029	250
1999	7.20%	2039	250
Unamortized debt discount			(42)
Total			$ 1,408

Included in Minority Interest Expense on the Consolidated Statements of Operations are dividends related to the trust preferred securities of $55 million for 2003, and $108 million for 2002 and 2001.

16. Preferred and Preference Stock at Duke Energy

Authorized Shares of Duke Energy Preferred and Preference Stock as of December 31, 2003 and 2002

	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, 2003 and 2002, there were no shares of preference stock outstanding at Duke Energy.

Preferred Stock with Sinking Fund Requirements. Upon the adoption of SFAS No. 150, effective July 1, 2003, as discussed in Note 1, $23 million of preferred stock previously included on the Consolidated Balance Sheets as Preferred and Preference Stock with Sinking Fund Requirements was reclassified to Long-term Debt. The $23 million of preferred stock are mandatorily redeemable financial instruments under the provisions of SFAS No. 150, due to the annual $2 million sinking fund requirements in cash, at par value, through 2015.

Also, effective July 1, 2003, payments made to the holders of this preferred stock have been classified in the Consolidated Statements of Operations as Interest Expense, rather than Dividends and Premiums on Redemptions of Preferred and Preference Stock. In accordance with the requirements of SFAS No. 150, prior period amounts have not been reclassified.

Preferred Stock with Sinking Fund Requirements

Rate/Series	Year Issued	Shares Issued and Outstanding at December 31, 2002	Balance as of December 31, 2002
			(dollars in millions)
6.75% X	1993	250,000	$ 25

See Note 14 for details on the December 31, 2003 outstanding balance of Preferred Stock with Sinking Fund Requirements.

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Notes To Consolidated Financial Statements Continued

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, 2003 and 2002 Consolidated Balance Sheets.

Preferred Stock without Sinking Fund Requirements

Rate/Series	Year Issued	Shares Issued and Outstanding at December 31, 2003	December 31, 2003	December 31, 2002
			(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.

Preferred and Preference Stock of Duke Energy s Subsidiaries. Upon the adoption of SFAS No. 150 on July 1, 2003, $23 million of DEFS preferred members interest held by ConocoPhillips, which had previously been included on the Consolidated Balance Sheets as Minority Interests was reclassified to Long-term Debt. The $23 million of preferred members interest were mandatorily redeemable financial instruments under the provisions of SFAS No. 150, since the redemption of the securities was required in cash, at par value, upon the earlier of 30 years from the date of issuance (August 2030) or an initial public offering of equity securities by DEFS. As of December 31, 2003, DEFS had redeemed all outstanding amounts of the preferred members interest.

In connection with the Westcoast acquisition, Duke Energy assumed approximately $411 million of authorized and issued redeemable preferred and preference shares at Westcoast and Union Gas. As of December 31, 2003, these preferred and preference shares at Westcoast and Union Gas totaled $401 million. Since these preferred and preference shares are redeemable at the option of holder, as well as Westcoast and 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 insurance coverage 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

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

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, and (4) 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.

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 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 $10.9 billion.

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

Excess Liability Insurance. This policy currently provides approximately $10.6 billion of coverage through the Price-Anderson Act s mandatory industry-wide excess secondary insurance program of risk pooling. The $10.6 billion is the sum of the current potential cumulative retrospective premium assessments of $100.6 million per licensed commercial nuclear reactor. This would be increased by $100.6 million for each additional commercial nuclear reactor licensed, or reduced by $100.6 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 $100.6 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 $100.6 million is subject to indexing for inflation and may be subject to state premium taxes.

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.

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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 $34 million, Excess Property Insurance $39 million and Business Interruption Insurance $28 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. Duke Energy and its affiliates are responsible for environmental remediation at various impacted properties or contaminated sites similar to others in the energy industry. These include some properties that are part of ongoing Duke Energy operations, as well as sites formerly owned or used by Duke Energy entities and sites owned by third parties. These matters typically involve management of contaminated soils and may involve ground water remediation. They are managed in conjunction with the relevant federal, state and local agencies. These sites or matters vary, for example, with respect to site conditions and location, remedial requirements, sharing of responsibility by other entities, and complexity. Certain matters can involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, whereby Duke Energy or its affiliates could potentially be held responsible for contamination caused by other parties. In some instances, Duke Energy may share any liability associated with contamination with other potentially responsible parties, and Duke Energy may 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 the respective 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.

Air Quality Control. In 1998, the Environmental Protection Agency (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 implementation of emission reductions to May 31, 2004. Both North Carolina and South Carolina have revised their SIPs in response to the EPA s 1998 rule, and the EPA has approved these revisions. Duke Energy has incurred approximately $628 million in capital costs for emission controls through 2003 for compliance with the EPA s rule. Management estimates that Duke Energy s remaining capital expenditures to complete the installation of emission controls needed to comply with the EPA s rule will be approximately $40 million. These remaining expenditures will be incurred by Duke Power in 2004.

In June 2002, the state of North Carolina passed new clean air legislation that includes provisions that freezes electric utility rates from June 20, 2002 (the effective date of the statute) to December 31, 2007 (rate

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Notes To Consolidated Financial Statements Continued

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 over the next ten years. Management estimates Duke Energy s cost of achieving the proposed emission reductions over the next ten years to be approximately $1.5 billion in total. Included in the legislation are provisions that allow these electric utilities, including Duke Energy, to accelerate the recovery of these compliance costs by amortizing them over seven years (2003-2009). In addition, the legislation permits Duke Energy the flexibility to vary the amortization schedule for recording of the compliance costs. During the rate freeze period, Duke Energy is expected to recover a minimum of 70% of the total estimated costs of plant improvements. The maximum annual accelerated cost recovery during the rate freeze period cannot exceed 150% of the annual levelized compliance costs. In 2003, amortization of compliance costs were approximately 54% of the annual levelized compliance costs. In accordance with the legislation, the amortization, of compliance costs will vary in future years. In years six and seven of the recovery period, the NCUC will determine how any remaining costs will be recovered. Emission control retrofits needed to comply with the new legislation are large technical, design and construction projects. These projects will be managed closely to ensure the continuation of reliable electric service to Duke Energy s customers throughout the projects and upon their completion.

Global Climate Change. The United Nations-sponsored Kyoto Protocol prescribes specific greenhouse gas emission reduction targets to developed countries as a response to concerns over global warming and climate change, with a focus on lowering such emissions at the source, including among others fossil-fueled electric power generation and natural gas operations. In 2001 President George W. Bush declared that the U.S. would not ratify the Kyoto Protocol. Canada is presently the only country in which Duke Energy has assets that would have a greenhouse gas reduction obligation under the Kyoto Protocol. If Russia ratifies the Kyoto Protocol, it will enter into force and Canada will be obligated to reduce its average greenhouse gas emissions to 6% below 1990 levels over the period 2008 to 2012. The Canadian government is in the process of developing an implementation plan that includes a carbon dioxide (CO2) cap and trade program for large industrial emitters (LIE), and Parliament is expected to consider authorizing legislation by the end of 2004. If an LIE program is enacted then all of Duke Energy s Canadian operations would likely be subject to such a program, with compliance options ranging from purchase of CO2 emissions credits to actual emissions reductions at the source, or a combination of strategies. Canada s new Prime Minister, Paul Martin, has voiced some questions regarding Canadian climate change strategy, and intends to review it this year. Canadian carbon emissions management policy could change as a result, or if the Kyoto Protocol does not enter into force. The final outcome is still highly uncertain.

In the U.S., administration 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 CO2 emissions reductions, none have advanced through the legislature and there are presently no federal mandatory greenhouse gas reduction requirements. The likelihood of any federal mandatory CO2 emissions reduction regime being enacted in the near future, or the specific requirements of any such regime that were to become law, is highly uncertain. Some states are contemplating or have taken steps to manage greenhouse gas emissions, and while a number of states in the Northeast and far West recently began discussing the possible implementation of regional greenhouse gas reduction programs in the future, the outcome of such discussions is very uncertain. To the extent that a Kyoto Protocol emissions reductions regime comes into legal effect, or that significant greenhouse gas emissions reduction policies are legally adopted or promulgated in non-Kyoto jurisdictions, including the U. S. or its various states, such mandatory emissions reduction requirements could have far-reaching and significant implications for industry in those jurisdictions, including the respective energy sectors. Duke Energy cannot estimate with certainty the potential effect of the Canadian greenhouse gas reduction policy currently under development or estimate the potential effect of U.S. federal or state level greenhouse gas policy on future consolidated results of operations, cash flows or financial position due to the uncertainty of the Canadian policy

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and the speculative nature of U.S. federal and state policy. Duke Energy stays abreast of and engaged in the greenhouse gas policy developments of the countries, states and regions in which it operates, and will continue to assess and respond to their potential implications for Duke Energy s business operations in the U.S., Canada and around the world.

Extended Environmental Activities, Accruals. Included in Other Current Liabilities and Other Deferred Credits and Other Liabilities were accruals related to extended environmental-related activities of $94 million as of December 31, 2003 and $97 million as of December 31, 2002. The accrual for extended environmental-related activities represents Duke Energy s provisions for costs associated with some of its current and former sites and certain other environmental matters. 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 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 on April 15, 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 filed its appeal of the judgment to the U.S. 4th Circuit Court of Appeals in June 2004. 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 an appellate court could significantly affect the outcome.

*Western Energy Litigation***.** Commencing in 2000, plaintiffs have filed and served 31 lawsuits in state and federal courts in California, Montana, Oregon and Washington against numerous energy companies, including Duke Energy affiliates, and current and former Duke Energy executives. Most of these suits seek class action certification on behalf of purchasers of electric and/or natural gas energy residing in the states of California, Oregon, Washington, Utah, Nevada, Idaho, New Mexico, Arizona and Montana. The plaintiffs allege that the defendants manipulated the electricity and/or natural gas markets in violation of various state and/or federal antitrust, unfair business practices, and other laws. Plaintiffs in certain 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, eight suits have been dismissed on filed rate and federal preemption grounds.

Plaintiffs are appealing the dismissals. One suit was dismissed voluntarily.

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In July 2004, Duke Energy reached an agreement in principle resolving the class-action litigation involving the purchase of electricity filed on behalf of ratepayers and certain other electricity consumers in California, Washington, Oregon, Utah and Idaho. This agreement is part of a more comprehensive agreement involving the FERC refunds and other proceedings. This agreement (California Agreement) is addressed in more detail in the *Western Energy Regulatory Matters and Investigations* paragraph 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, based on rulings by trial courts and the California Settlement, 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. Subsequent rulings by appellate courts could significantly affect the outcome.

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 $80 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. Several investigations and regulatory proceedings at the state and federal levels are looking into the causes of high wholesale electricity prices in the western U.S. during 2000 and 2001. Duke Energy has resolved these issues which are described in detail below, through the California Settlement.

In the FERC refund proceedings, the FERC has 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 a refund liability of approximately $95 million.

The FERC issued staff recommendations and an order in 2003 relating to the refund proceeding and investigations into the causes of high wholesale electricity prices in the western U.S. during 2000 and 2001. The Order modified the prior refund methodology by changing the gas proxy price used in the refund calculation. Duke Energy cannot predict with certainty the outcome of the methodology change, but Platts, an energy industry publication, reported that a FERC spokesman announced that the methodology change could result in an increase in the total aggregate refund amount for all generators from $1.8 billion to at least $3.3 billion. The 2003 order allowed generators to receive a gas cost credit in instances where companies incurred fuel costs exceeding the gas proxy price. DENA and DETM submitted gas cost data to the FERC and sought a gas price credit in the range of $72 million. The California parties challenged both the amount and availability of the credit. Resolution of the refund proceeding is included in the California Settlement.

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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 California Power Exchange markets made above the level of $250 per megawatt hour from May 1, 2000 through October 1, 2000. Also in 2003, the FERC Staff and Duke Energy announced two agreements to resolve all matters at issue in both of these orders. Duke Energy agreed to pay up to $4.59 million to the benefit of California and western electricity consumers, pending final approval by the FERC. The FERC approved the agreement involving bidding practices and rejected the California parties objections to the agreement. The California parties sought review of the FERC s ruling on this agreement from the 9th Circuit U.S. Court of Appeals. On April 19, 2004, the administrative law judge reviewing the remaining agreement issued a certification approving the settlement and rejecting the California parties objections. That agreement was submitted to the FERC for review. The California Parties challenge of the two agreements is 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 are conducting formal and informal investigations involving some Duke Energy entities 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, in general, information relating to possible manipulation of the electricity markets in California, including potential antitrust violations. All 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.

In July 2004, Duke Energy reached an agreement in principle (California Settlement), to settle the FERC refund proceedings and other significant litigation related to the western energy markets during 2000-2001. The parties to the settlement agreement include FERC staff, the state of California, the state of Washington, the state of Oregon, PG&E, SCE, San Diego Gas & Electric Company, the California Department of Water Resources, the CPUC staff, private litigants and Duke Energy. The settlement is subject to approval by FERC and CPUC, and the class-action settlements are subject to court approval.

As part of the agreement, Duke Energy will provide approximately $208 million in cash and credits. In exchange, the parties to the agreement will forgo all claims relating to refunds or other monetary damages for sales of electricity during the settlement period, and claims alleging Duke Energy received unjust or unreasonable rates for the sale of electricity during the settlement period. The settlement resolves:

- All western refund proceedings pending before the FERC
- Market price investigations by attorneys general in California, Washington and Oregon
- Private electricity-related class-action litigation filed on behalf of California, Washington, Oregon, Idaho and Utah ratepayers
- Natural gas price issues raised by the California attorney general, PG&E, SCE and San Diego Gas & Electric Company.

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Notes To Consolidated Financial Statements Continued

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.

Financial Effect of California Settlement (in millions)

Cash	$ 85
Write-off of receivables and credits due to Duke Energy	123
Settlement total	**208**
Reserves and offsets	(103)
Second quarter 2004 pre-tax earnings impact	**$ 105**

Trading Related Litigation. Beginning in 2002, 17 shareholder class-action lawsuits were filed against Duke Energy: 13 in the United States District Court for the Southern District of New York and four in the United States 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 have appealed the dismissal order to the Second Circuit United States Court of Appeals. By letter dated April 16, 2004, Duke Energy received notice that a shareholder has reactivated a litigation demand previously sent to Duke Energy in 2002. This demand arises out of the same issues raised in the dismissed shareholder lawsuits. The notice states that the shareholder intends to initiate derivative shareholder litigation within 90 days from the date of the letter. Duke Energy s Board of Directors appointed a special committee to review the demand. The special committee determined that there are no grounds with respect to the allegations made in the derivative demand to commence or maintain an action on behalf of Duke Energy against the individuals named in such derivative demand, and that, accordingly, it would not be in the best interests of Duke Energy to bring such claims.

In July 2003, a former trader with DEM brought a lawsuit against Duke Energy, DENA and DEM in federal court in the Southern District of Texas that included allegations of round trip trading and accounting issues and asserted claims of securities fraud and employment related claims relating to options and stock acquired by him as part of his compensation package. The parties settled the lawsuit, and the court dismissed the case in December 2003. The settlement was not material.

Since August 2003, plaintiffs have filed three class action lawsuits brought on behalf of entities who bought and sold natural gas futures and options contracts on the New York Mercantile Exchange during the years 2000 through 2002 in federal district court for the Southern District of New York. The lawsuits initially named Duke Energy as a defendant, along with numerous other entities. In the latest consolidated complaint filed in January 2004, the plaintiffs dropped Duke Energy from the cases and added DETM as a defendant. Plaintiffs claim 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. These cases are in very early stages. 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.

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.

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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. The investigation remains open, and Duke Energy cannot predict the outcome.

On April 21, 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. The indictments further state that the alleged conduct was purportedly motivated, in part, by a desire to increase individual bonuses. In statements made by the U.S. Attorney s office, Duke Energy was characterized as a victim in this activity and was commended 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 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 is cooperating with the government in this investigation and cannot predict the outcome.

In the fourth quarter of 2002, the Commodity Futures Trading Commission (CFTC) issued data requests to DETM seeking information concerning natural gas price data submitted to publishers of natural gas price indices. In September 2003, DETM and the CFTC reached a settlement regarding reporting of natural gas trading information that occurred prior to September 2002. On September 17, 2003, the CFTC filed and simultaneously approved an order settling an administrative action against DETM. The CFTC order states DETM s Houston offices knowingly reported trades that did not occur and reported certain trades at false prices and/or volumes. DETM agreed to pay a civil penalty of $28 million without admitting or denying the CFTC s findings. Duke Energy recorded a $17 million charge, net of minority interest, in the third quarter of 2003 to reflect the settlement. The previous practices in question were isolated in one area of DETM, its natural gas trading operation in the Eastern market, based in Houston.

Sonatrach/Citrus Trading Corporation (Citrus). Duke Energy LNG Sales, Inc. (Duke LNG) claims in an arbitration 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. Sonatrading and Sonatrach claim that Duke LNG repudiated the LNG Agreements by allegedly failing to perform LNG marketing obligations. In 2003, the arbitration panel issued its Partial Award on liability issues, finding that Sonatrach and Sonatrading breached their obligations to provide shipping, rendering them liable to Duke LNG for any resulting damages. The arbitration panel also found that Duke LNG breached the LNG Purchase Agreement by failing to perform marketing obligations. Also in 2003, Sonatrading terminated the LNG Agreements and seeks in the arbitration to recover resulting damages from Duke LNG. The final hearing on damages issues has been tentatively scheduled for September 2005.

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 Texas against Duke LNG (now pending in federal district court in Houston, Texas) 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 a loss of LNG supply.

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Following the commencement of the Citrus litigation, Duke LNG terminated the Citrus Agreement and filed a counterclaim in the Texas action asserting that Citrus breached the terms of the Citrus Agreement by among other things, failing to provide sufficient security 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. On March 16, 2004, Citrus filed suit against PanEnergy Corp (PanEnergy) in the Harris County, Texas district court alleging that PanEnergy is financially responsible for losses incurred by Citrus as a result of Duke LNG s alleged breaches. The action against PanEnergy now has been consolidated with the original Citrus lawsuit in federal court. No trial date has been set for these matters and discovery is proceeding. 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.

Enron Bankruptcy. In December 2001, Enron filed for relief pursuant to Chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York. Additional affiliates have filed for bankruptcy since that date. Certain affiliates of Duke Energy engaged in transactions with various Enron entities prior to the bankruptcy filings. In 2001, Duke Energy recorded a reserve to offset its exposure to Enron. In 2002, various Enron trading entities demanded payment from DETM and DEM for certain energy commodity sales transactions without regard to any set-off rights. DETM and DEM filed an adversary proceeding against Enron, seeking, among other things, a declaration affirming each plaintiff s right to set off its respective debts to Enron. In 2003, DETM, DEM and other Duke Energy affiliates entered into an agreement in principle with Enron and its trading entities to resolve the outstanding disputes pending before the bankruptcy court. The proposed agreement was approved by the Unsecured Creditor s Committee and on March 11, 2004, the bankruptcy court approved the settlement. No party appealed the court s approval of the agreement prior to the April 12, 2004 deadline, and the agreement is final. The terms of the agreement are confidential but resulted in a net pre-tax gain in the second quarter of 2004 of approximately $130 million (net of minority interest expense of $5 million), due to the write-off of net payables to Enron reflected on the March 31, 2004 Consolidated Balance Sheet. Of the gain, $113 million was recorded at DENA, $21 million at DEM and $1 million at Field Services as a credit to Operation, Maintenance and Other on the Consolidated Statements of Operations.

AES Puerto Rico LP (AES). On June 9, 2003, AES filed suit against Duke/Fluor Daniel Caribbean, S.E. (D/FD Caribbean) and others, including Duke Capital, in Delaware federal court, alleging claims in excess of $100 million arising out of the construction by D/FD Caribbean of a coal fired power plant in Puerto Rico. D/FD Caribbean disputed the allegations made by AES and alleged its own claims, in excess of $50 million. Duke Energy holds an indirect 50% ownership interest in D/FD Caribbean through its affiliate D/FD. The parties settled their disputes in November 2003. The results of the settlement did not have a material adverse effect on Duke Energy s consolidated results of operations, cash flows or financial position.

Hubline Construction Disputes. A number of disputes arose during 2003 between Algonquin Gas Transmission (Algonquin) and Maritimes & Northeast Pipeline, L.L.C. (Maritimes) and several of their contractors who provided construction and related services for Algonquin s Hubline gas pipeline constructed in and around Boston Harbor, Massachusetts and the related Phase III expansion of the Maritimes pipeline. Algonquin and Maritimes participated in dispute resolution proceedings in late 2003 with Stolt Offshore Inc. (Stolt), Algonquin s main contractor on the Hubline project and with Michels Corporation (Michels), a contractor on both the Hubline and Phase III projects. Algonquin and Maritimes have resolved all material claims arising out of the Hubline and Phase III projects. The Stolt settlement includes Stolt s commitment to indemnify Algonquin with respect to any remaining subcontractor claims and lawsuits. Only immaterial claims relating to Murphy Bros. and its work on the related Phase III expansion of Maritimes remain open. The results of these settlements did not have a material adverse effect on Duke Energy s consolidated results of operations, cash flows or financial position.

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North Carolina Grand Jury Investigation. In February 2003, Duke Energy received a Western District of North Carolina Grand Jury subpoena for documents related to the audit by the NCUC and the PSCSC of Duke Power regarding certain Duke Power regulatory accounting entries from 1998 to 2000. On March 10, 2004, Duke Energy received notice from the U.S. Attorney for the Western District of North Carolina that its investigation had been closed and that no action against Duke Energy or any individuals was warranted.

ExxonMobil Disputes. On April 8, 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. 3946231 and DTMSI are the sole beneficial owners of Duke Energy Marketing Limited Partnership (DEMLP, and with DETM, the Ventures). Among other allegations, ExxonMobil claims that DETMI and DTMSI engaged in allegedly wrongful actions relating to affiliate trading, payment of service fees, expense allocations and distribution of earnings in breach of the agreements and fiduciary duties relating to the Ventures. ExxonMobil seeks to recover actual damages, plus attorneys fees and exemplary damages. These amounts are not clearly quantified in the arbitration demand. Duke Energy denies these allegations, will vigorously defend against ExxonMobil s claims and has filed counterclaims asserting that ExxonMobil breached its venture obligations and other contractual obligations. These matters are in very early stages. It is not possible to predict with certainty whether Duke Energy or any of its affiliates will incur any liability as a result of these matters or to estimate the damages, if any, that might be incurred.

On November 13, 2003, MNGI filed a Demand for Arbitration against Duke Energy and DETMI. MNGI claims that, under the terms of the limited liability company agreement of DETM and general fiduciary principles, DETMI and Duke Energy have full financial responsibility for the settlement reached between DETM and the CFTC. MNGI demands reimbursement for a 40% share of the $28 million CFTC settlement, plus 40% of all related expenses incurred by DETM. On March 5, 2004, MNGI filed an amended claim, adding DENA as a party. In June 2004, the parties settled this dispute. Due to a previously established reserve, the settlement did not have a material adverse effect on Duke Energy s consolidated results of operations, cash flows or financial position.

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. In late 1999, after experiencing a significant increase in claims and conducting a comprehensive review, Duke Energy recorded an $800 million accrual to reflect the purchase of a third-party insurance policy as well as estimated amounts for future claims not recoverable under such policy. The insurance policy, combined with amounts covered by self-insurance reserves, provides for claims paid up to an aggregate of $1.6 billion. Duke Energy conducted another review in 2003 and continues to believe the estimated claims relating to this exposure will not exceed such amount. Duke Energy is uncertain as to the timing of when claims will be received, and portions of the estimated claims may not be received and paid for 30 or more years. While Duke Energy has recorded an accrual related to this estimated liability, such estimates cannot be made with certainty and may change. Factors, such as the frequency and magnitude of claims, could result in changes in the estimates of the injuries and damages liability and insurance recoveries. Such changes could result in, over time, a difference from the amount currently reflected in the consolidated financial statements. However, due to Duke Energy s insurance program relating to this liability, management believes that any changes in the estimates would not have a material adverse effect on 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 before various courts, regulatory commissions and governmental agencies regarding

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Notes To Consolidated Financial Statements Continued

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 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 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. (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 Lease Commitments

Duke Energy leases assets in several areas of its operations. Consolidated rental expense for operating leases was $133 million in 2003, $133 million in 2002 and $114 million in 2001. Amortization of assets recorded under capital leases was included in depreciation expense. The following is a summary of future minimum rental payments under operating leases, which at inception had a noncancelable term of more than one year, as of December 31, 2003:

2004	$ 98
2005	72
2006	55
2007	41
2008	35
Thereafter	207

Total future minimum lease payments	$ 508

Sale-Leaseback Transaction. In May 2003, Duke Energy entered into an agreement to sell its 5400 Westheimer Court office building in Houston, Texas to an unrelated third-party for approximately $78 million, which has been included as an investing activity in the Consolidated Statements of Cash Flows. The transaction has been accounted for as a sale-leaseback transaction whereby Duke Energy sold the building but will lease it back over a 15-year lease term. The lease expires in April 2018, with two five-year extensions exercisable at Duke Energy s option. Duke Energy may also terminate the lease early, in April 2016, without penalty. The future minimum lease payments under the lease are approximately $100 million. Duke Energy does not have an

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option to purchase the leased facilities at the end of the minimum lease term and has not issued any residual value guarantee of the value of the leased facilities. As such, the gain on the sale of approximately $17 million will be amortized over the minimum term of the lease, which has been accounted for as an operating lease by Duke Energy.

18. Guarantees and Indemnifications

Duke Energy and certain of 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 U.S. Department of Energy (the DOE) under a contract (the Prime Contract) in which DCS will design, construct, operate and deactivate a MOX fuel fabrication facility (the MOX FFF). The domestic MOX fuel project was prompted by an agreement between the U.S. 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, 2003, Duke Energy Corporation, through its indirect wholly owned subsidiary, Duke Project Services Group, Inc. (DPSG), held a 40% ownership interest in DCS. Additionally, Duke Power has entered into a subcontract with DCS (the Duke Power Subcontract) to prepare the McGuire and Catawba nuclear reactors (the Nuclear Reactors) for use of the MOX fuel and to provide for certain terms and conditions applicable to the purchase of MOX fuel produced at the MOX FFF for use in the Nuclear Reactors.

DPSG and the other owners of DCS have issued a guarantee to the DOE (the DOE Guarantee) pursuant to which the owners of DCS jointly and severally guarantee to the DOE all of DCS payment and performance obligations under the Prime Contract. The Prime Contract consists of a Base Contract phase and four option phases. The DOE has the right to extend the term of the Prime Contract to cover the four 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. Each of the four option phases will be negotiated separately, as the time for exercising each option phase becomes due under the Prime Contract. If the DOE does not exercise its right to extend the term of the Prime Contract to cover any or all of the option phases, DCS performance obligations under the Prime Contract will end upon completion of the then-current performance phase. Additionally, the DOE has the right to terminate the Prime Contract for convenience at any time. Under the Base Contract phase, which covers the design of the MOX FFF and design modifications to the Nuclear Reactors, DCS is to receive cost reimbursement plus a fixed fee. The first option phase includes the modification of Nuclear Reactors and related Duke Power facilities, and provides for DCS to receive cost reimbursement plus an incentive fee. The second option phase includes the construction and cold startup of the MOX FFF, and provides for DCS to receive cost reimbursement plus an incentive fee. The third option phase provides for taking the MOX FFF from cold to hot startup, operation of the MOX FFF, and irradiation of the MOX fuel in the Nuclear Reactors; and provides for DCS to receive a cost reimbursement plus an incentive fee through hot startup and, thereafter, cost-sharing plus a fee. The fourth option phase involves DCS deactivation of the MOX FFF in exchange for a fixed price payment. In September 2003, the DOE exercised its right to extend the term of the Prime Contract to cover the first option phase and DCS and the DOE agreed to add the related terms and conditions to the Prime Contract. As of December 31, 2003, DCS performance obligations under the Prime Contract included only the Base Contract phase and the first option phase.

Additionally, DPSG and the other owners of DCS have issued a guarantee to Duke Power (the Duke Power Guarantee) under which the owners of DCS jointly and severally guarantee to Duke Power all of DCS payment

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Notes To Consolidated Financial Statements Continued

and performance obligations under the Duke Power Subcontract or any other agreement between DCS and Duke Power implementing the Prime Contract. The Duke Power Subcontract consists of a Base Subcontract phase and three option phases. DCS has the right to extend the term of the Duke Power Subcontract to cover the three 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. Under the Base Subcontract phase, Duke Power will perform technical and regulatory work required to prepare the Nuclear Reactors to use MOX fuel and will receive cost reimbursement plus a fixed fee. The first option phase includes Duke Power s modification of the Nuclear Reactors and related Duke Power facilities, and provides for Duke Power to receive cost reimbursement plus a fee. The second option phase includes Duke Power performance of additional technical and regulatory work, and provides for Duke Power to receive cost reimbursement plus a fee. The third option phase provides for Duke Power to purchase from DCS MOX fuel produced at the MOX FFF for use in the Nuclear Reactors, at discounts to prices of equivalent uranium fuel, over a 15-year period starting upon completion of the second option phase. In October 2003, DCS exercised its right to extend the term of the Duke Power Subcontract to cover the first option phase and Duke Power and DCS agreed to add the related terms and conditions to the Duke Power Subcontract. As of December 31, 2003, DCS s performance obligations under the Duke Power Subcontract included only the Base Subcontract phase and the first option phase.

The cost reimbursement nature of DCS commitment under the Prime Contract and the Duke Power Subcontract limits the exposure of DCS. Credit risk to DCS is limited in that the Prime Contract is with the DOE, a U.S. governmental entity. DCS is under no obligation to perform any contract work under the Prime Contract before funds have been appropriated from the U.S. Congress with respect to such work.

As of December 31, 2003, Duke Energy was unable to estimate the maximum potential amount of future payments DPSG could be required to make under the DOE Guarantee and the Duke Power Guarantee due to the uncertainty of whether: (i) the DOE will exercise its options under the Prime Contract; (ii) 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; and (iii) the U.S. Congress will authorize funding for DCS work under the Prime Contract. Even though neither the DOE Guarantee nor the Duke Power Guarantee provide for a specific limitation on a guarantor s payments, any liability of DPSG under the DOE Guarantee or the Duke Power Guarantee is directly related to and limited by the terms and conditions contained in the Prime Contract and the Duke Power Subcontract and any other agreements between Duke Power and DCS implementing the Prime Contract, respectively. DPSG also has recourse to the other owners of DCS for any amounts paid under the DOE Guarantee or the Duke Power Guarantee in excess of its proportional ownership percentage of DCS.

On April 15, 2004, DCS and the DOE entered into an amendment to the Prime Contract that, among other things, clarified that the DOE Guarantee solely covers the guarantors obligations to reimburse the DOE, in the event 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. Even though the DOE Guarantee does not provide for a specific limitation on the guarantor s reimbursement obligations, Duke Energy estimates that the maximum potential amount of future payments DPSG could be required to make under the DOE Guarantee has been significantly reduced and is considered immaterial, as a result of the amendment discussed above.

As of December 31, 2003, Duke Energy had no liabilities recorded on its Consolidated Balance Sheet for the above mentioned MOX guarantees.

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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, 2003 was approximately $650 million. Of this amount, approximately $375 million relates to guarantees of the payment and performance of less than wholly owned consolidated entities. Approximately $25 million of the performance guarantees expire between 2004 and 2005, approximately $300 million expire in 2006 and thereafter, with the remaining performance guarantees having no contractual expiration. Additionally, Duke Capital has issued joint and several guarantees to certain of the D/FD project owners, which guarantee 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 D/FD partners is responsible for 50% of any payments to be made under these guarantee contracts.

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. These performance guarantees require Westcoast to make payment to the guaranteed third party upon the failure of the unconsolidated entity to make payment under certain 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 these performance guarantees as of December 31, 2003 was approximately $50 million. Of these guarantees, approximately $30 million expire from 2004 to 2007, with the remainder expiring after 2007 or 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 under the letter of credit due to the failure of the non-wholly owned entity to perform according to the terms of its underlying contract. These letters of credit principally expire in 2004. The maximum potential amount of future payments Duke Capital could have been required to make under these letters of credit as of December 31, 2003 was approximately $200 million. Of this amount, approximately $150 million relates to letters of credit issued on behalf of less than wholly owned consolidated entities.

Duke Capital has guaranteed the issuance 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, 2003, Duke Capital had guaranteed approximately $75 million of outstanding surety bonds related to obligations of non- wholly owned entities. These bonds expire in various amounts, primarily in 2004. Of this amount, approximately $15 million relates to obligations of less than wholly owned consolidated entities.

Natural Gas Transmission and International Energy have issued certain guarantees of debt associated with non-consolidated entities and less than wholly-owned entities. In the event that non-consolidated entities or less than wholly-owned entities default on the debt payments, Natural Gas Transmission or International Energy would be required to perform under the guarantees and make payment on the outstanding debt balance of the non-consolidated entity. As of December 31, 2003, Natural Gas Transmission was the guarantor of approximately $15 million at Westcoast of debt associated with less than wholly-owned entities, with no contractual expiration. International Energy was the guarantor of approximately $10 million of debt associated with less than wholly-owned entities, which principally expire in 2004.

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Duke Energy has certain guarantees issued to customers or other third parties related to the payment or performance obligations of certain entities that were previously wholly owned 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. In connection with the sale of DE&S, Duke Energy has received back-to-back indemnification from the buyer indemnifying Duke Energy for any amounts paid by Duke Energy related to the DE&S guarantees. In connection with the sale of DukeSolutions, Duke Energy received indemnification from the buyer for the first $2.5 million paid by Duke Energy related to the DukeSolutions guarantees. 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 guaranteed agreements contain no limits on potential liability.

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 indemnification agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements. Typically, claims may be made by third parties under these indemnification agreements 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 dollar amount to an unlimited 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 under these indemnities.

As of December 31, 2003, the amounts recorded for the guarantees and indemnifications mentioned above are immaterial both individually and in the aggregate.

19. Earnings Per Common Share

Basic earnings per share is computed by dividing earnings available for common shareholders by the weighted-average number of common shares outstanding during the period. Diluted earnings per share is computed by dividing earnings available for common shareholders 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, equity units, stock-based performance unit awards, convertible debt and phantom stock awards, were exercised or converted into common stock. The following table reconciles the weighted-average number of common shares outstanding to the diluted weighted-average number of common shares outstanding.

Weighted-Average Shares Outstanding

	2003	2002	2001
		(in millions)	

Weighted-average shares outstanding	903.0	836.1	767.5
Assumed exercise of dilutive securities or other agreements to issue common stock		2.0	5.4
Diluted weighted-average shares outstanding	903.0	838.1	772.9

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Options, performance awards and phantom stock awards to purchase approximately 33.6 million shares as of December 31, 2003 were not included in the computation of diluted earnings per share because a loss from continuing operations existed, and thus including these shares in the computation would have been antidilutive as it would have decreased the loss per share.

Options, performance awards and phantom stock awards to purchase approximately 31.4 million shares as of December 31, 2002 and 6.0 million shares as of December 31, 2001 were not included in the computation of diluted earnings per share because the option exercise prices were greater than the average market price of the common shares during those periods.

Duke Energy s $1.625 million of Equity Units, which will result in an issuance of approximately 41.5 million shares, is not included in potential dilution for the period in the above table because their inclusion would be antidilutive.

Additionally, Duke Energy s $770 million convertible debt issuance, which is potentially convertible into approximately 33 million shares, is not included in potential dilution for the period in the above table because the market price and other contingencies for issuance has not been met as of December 31, 2003.

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 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, 2000	22,506	$ 31
Granted	7,090	37
Exercised	(2,285)	25
Forfeited	(905)	33
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

(a) Includes 2,746,044 converted Westcoast stock options

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Stock Options at December 31, 2003

	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
$ 5 to $10	193	1.0	$ 10	193	$ 10
$11 to $14	5,772	8.9	14	190	13
$15 to $20	2,298	8.9	17	915	18
$21 to $24	508	5.2	22	446	22
$25 to $28	6,365	5.6	26	6,096	26
$29 to $33	4,212	4.9	30	4,105	30
$34 to $37	1,185	7.8	35	444	35
$38 to $39	7,100	8.0	38	4,545	38
> $39	4,783	7.0	43	3,504	43
Total	32,416	7.1		20,438	32

As of December 31, 2002, Duke Energy had 19.1 million exercisable options with a $32 weighted-average exercise price. As of December 31, 2001, Duke Energy had 7.9 million exercisable options with a $28 weighted-average exercise price.

The weighted-average fair value per option granted was $4 for 2003, and $10 for 2002 and 2001. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model.

Weighted-Average Assumptions for Option-Pricing

	2003	2002	2001
Stock dividend yield	3.5%	3.4%	3.4%
Expected stock price volatility	37.5%	29.9%	29.5%
Risk-free interest rates	3.6%	5.0%	5.0%
Expected option lives	7 years	7 years	7 years

The 1998 Plan allows for a maximum of 12 million shares of common stock to be issued in the form of restricted stock awards, 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 year three, at the earliest if performance is met. Duke Energy awarded 75,000 shares (fair value of approximately $2 million at grant dates) in 2003, 16,000 shares (fair value of approximately $1 million at grant dates) in 2002 and 24,000 shares (fair value of approximately $1 million at grant dates) in 2001. Compensation expense for the performance awards is charged to earnings over the vesting period, and totaled $3 million in 2003, $4 million in 2002 and $6 million in 2001.

Phantom stock awards granted under the 1998 Plan vest over periods ranging from one to four years. Duke Energy awarded 285,000 shares (fair value of approximately $5 million at grant dates) in 2003, 54,430 shares (fair value of approximately $2 million at grant dates) in 2002 and 457,700 shares (fair value of approximately $17 million at grant dates) in 2001. Compensation expense for the phantom awards is charged to earnings over the vesting period, and totaled $6 million in 2003, $10 million in 2002 and $4 million in 2001.

Restricted stock awards granted under the 1998 Plan vest over periods ranging from one to five years. Duke Energy awarded 19,897 shares (fair value of less than $1 million at grant dates) in 2003, 14,260 shares (fair value

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of less than $1 million at grant dates) in 2002 and 74,005 shares (fair value of approximately $3 million at grant dates) in 2001. Compensation expense for restricted awards is charged to earnings over the vesting period, and totaled $1 million in 2003, $2 million in 2002 and $3 million in 2001.

Duke Energy s 1996 Stock Incentive Plan (the 1996 Plan) allowed four million shares of common stock for awards to employees. Restricted stock grants under the 1996 Plan vest over periods ranging from one to five years. Duke Energy awarded no restricted shares in 2003 and 2002 and awarded 50,000 restricted shares (fair value of approximately $2 million at grant date) in 2001. Compensation expense for restricted awards is charged to earnings over the vesting period and totaled less than $1 million in 2003, and $1 million in 2002 and 2001.

21. Employee Benefit Plans

Duke Energy U.S. Retirement Plans. 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 $181 million to its U.S. defined benefit retirement plan in 2003. No contributions to the Duke Energy plan were necessary in 2002 or 2001. No decision on 2004 contributions has been reached due to significant uncertainty around pending U.S. Congressional action over required interest rates used to determine minimum funding requirements.

The net unrecognized transition asset, resulting from the implementation of accrual accounting, is amortized over approximately 20 years. Investment gains or losses are amortized over five years. Duke Energy uses a September 30 measurement date for its 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 policy is to fund the DB retirement 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 retirement plans are determined in accordance with the terms of the plan. Duke Energy made contributions to the Westcoast pension plans of approximately $11 million in 2003 and $9 million dollars in

2002. Duke Energy anticipates that it will make contributions of approximately $27 million to the Westcoast plans in 2004.

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.

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Components of Net Periodic Pension Costs as of December 31,

	Duke Energy U.S.			Westcoast	
	2003	2002	2001	2003	2002
			(in millions)		
Service cost benefit earned during the year	$ 70	$ 69	$ 74	$ 7	$ 6
Interest cost on projected benefit obligation	175	177	188	23	17
Expected return on plan assets	(236)	(267)	(264)	(24)	(19)
Amortization of prior service cost	(3)	(3)	(3)		
Amortization of net transition asset	(4)	(4)	(4)		
Curtailment loss				2	
Special termination benefit cost		1		5	
Net periodic pension (income) costs	$ 2	$ (27)	$ (9)	$ 13	$ 4

Reconciliation of Funded Status to Pre-funded Pension Costs as of December 31,

	Duke Energy U.S.		Westcoast	
	2003	2002	2003	2002
		(in millions)		
Change in Projected Benefit Obligation				
Obligation at prior measurement date	$ 2,671	$ 2,528	$ 334	$ 324
Service cost	70	69	7	6
Interest cost	175	177	23	17
Actuarial loss	60	73	27	6
Plan amendments	4	1		
Participant contributions			2	
Benefits paid	(217)	(178)	(25)	(19)
Curtailment			2	
Divestiture			(10)	
Special termination benefits		1		
Foreign currency impact			74	
Obligation at measurement date	$ 2,763	$ 2,671	$ 434	$ 334
Change in Fair Value of Plan Assets				

Plan assets at prior measurement date	$ 2,120	$ 2,470	$ 255	$ 291
Actual return on plan assets	393	(172)	35	(27)
Benefits paid	(217)	(178)	(25)	(19)
Employer contributions	181		11	9
Plan participants contributions			2	1
Divestiture			(9)	
Foreign currency impact			55	
Plan assets at measurement date	$ 2,477	$ 2,120	$ 324	$ 255
Funded status	$ (286)	$ (551)	$ (110)	$ (78)
Unrecognized net experience loss	816	913	79	49
Unrecognized prior service cost	(7)	(14)		
Special termination benefits			(5)	
Unrecognized net transition asset	(4)	(8)		
Contributions made after measurement date			3	2
Pre-funded (accrued) pension costs	$ 519	$ 340	$ (33)	$ (27)

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For the Duke Energy U.S. plan, the accumulated benefit obligation was $2,646 million at September 30, 2003 and $2,559 million at September 30, 2002.

For Westcoast, the accumulated benefit obligation was $394 million at September 30, 2003 and $303 million at September 30, 2002. The benefit obligation and fair value of plan assets at the beginning of the year 2002 represent balances assumed or acquired in the acquisition of Westcoast as of March 14, 2002.

Amounts recognized in the Consolidated Balance Sheets consist of:

	Duke Energy U.S.		Westcoast	
	2003	2002	2003	2002
	(in millions)			
Accrued pension liability	$ (170)	$ (432)	$ (70)	$ (49)
Deferred income tax asset	270	302	13	8
Accumulated other comprehensive income	419	470	21	14
Net Balance Sheet presentation	$ 519	$ 340	$ (36)	$ (27)

Additional Information:

	Duke Energy U.S.		Westcoast	
	2003	2002	2003	2002
	(in millions)			
Increase (decrease) in minimum liability included in other comprehensive income, net of tax	$ (51)	$ 470	$ 7	$ 14

Accumulated Benefit Obligation in Excess of Plan Assets

	Duke Energy U.S.		Westcoast	
	2003	2002	2003	2002
	(in millions)			
Projected benefit obligation	$ 2,763	$ 2,671	$ 432	$ 324
Accumulated benefit obligation	2,646	2,559	393	295
Fair value of plan assets	2,477	2,120	323	247

Assumptions Used for Pension Benefits Accounting

	Duke Energy U.S.			Westcoast	
	2003	2002	2001	2003	2002
			(percents)		
Benefit Obligations					
Discount rate	6.00	6.75	7.25	6.00	6.50
Salary increase	5.00	5.00	4.94	3.25	3.25
Net Periodic Benefit Cost					
Discount rate	6.75	7.25	7.50	6.50	7.25
Salary increase	5.00	5.00	4.94	3.25	3.25
Expected long-term rate of return on plan assets	8.50	9.25	9.25	7.75	8.50

For the Duke Energy U.S. plan the discount rate used to determine the pension obligation is based on average investment yields for Moody s AA long-term corporate bonds at the measurement date of September 30.

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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Duke Energy also sponsors employee savings plans that cover substantially all U.S. employees. Duke Energy expensed employer matching contributions of $63 million in 2003, $71 million in 2002 and $69 million in 2001.

Plan Assets Duke Energy U.S.:

Asset Category	Target Allocation	Percentage of Fair Value of Plan Assets at September 30 2003	2002
U.S. equity securities	45%	44%	44%
Non-U.S. equity securities	20	20	19
Debt securities	32	35	36
Real estate	3	1	
Cash equivalents / other			1
Total	100%	100%	100%

Duke Energy U.S. plan 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, 2003 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 4.18% for U.S. equities, 1.92% for Non U.S. equities, 2.21% for fixed income securities, and 0.24% for real estate.

Plan Assets Westcoast:

Asset Category	Target Allocation	Percentage of Fair Value of Plan Assets at September 30	
		2003	2002
Canadian equity securities	25%	37%	33%
U.S. equity securities	20	15	13
EAFE securities(a)	20	15	14
Debt securities	35	33	40
Total	100%	100%	100%

(a) EAFE Europe, Australasia, Far East

DUKE ENERGY CORPORATION

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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.

The long-term rate of return of 7.5% as of September 30, 2003 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 3.15% for Canadian equities, 1.27% for U.S. equities, 1.41% for Europe, Australasia and Far East equities, and 1.79% for fixed income securities.

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 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 as of December 31,

	Duke Energy U.S.			Westcoast	
	2003	**2002**	**2001**	**2003**	**2002**

	(in millions)				
Service cost benefit earned during the year	$ 5	$ 5	$ 5	$ 2	$ 2
Interest cost on accumulated post-retirement benefit obligation	51	50	44	4	2
Expected return on plan assets	(21)	(24)	(24)		
Amortization of prior service cost	1	1	1		
Amortization of net transition asset	18	18	18		
Curtailment loss (gain)	21		(3)	1	
Amortization of loss	5				
Net periodic post-retirement benefit costs	$ 80	$ 50	$ 41	$ 7	$ 4

During 2003, Duke Energy experienced workforce reductions and recognized other post-retirement employment benefits curtailments of $21 million.

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Reconciliation of Funded Status to Accrued Post-Retirement Benefit Costs as of December 31,

	Duke Energy U.S.		Westcoast	
	2003	2002	2003	2002
	(in millions)			
Change in Projected Benefit Obligation				
Accumulated post-retirement benefit obligation at prior measurement date	$ 779	$ 712	$ 49	$ 45
Service cost	5	5	2	2
Interest cost	51	50	4	2
Plan participants contributions	12	9		
Actuarial loss	142	66	30	2
Benefits paid	(66)	(63)	(2)	(2)
Divestiture			(2)	
Plan curtailments	1		1	
Plan amendments			(12)	
Foreign currency impact			11	
Accumulated post-retirement benefit obligation at measurement date	$ 924	$ 779	$ 81	$ 49
Change in Fair Value of Plan Assets				
Plan assets at prior measurement date	$ 227	$ 265	$	$
Actual return on plan assets	32	(21)		
Benefits paid	(66)	(63)	(2)	(2)
Employer contributions	37	37	2	2
Plan participants contributions	12	9		
Plan assets at measurement date	$ 242	$ 227	$	$
Funded status	$ (682)	$ (552)	$ (81)	$ (49)
Employer contributions made after measurement date	11	12	1	
Unrecognized net experience loss	346	223	32	2
Unrecognized prior service cost	2	3	(12)	
Unrecognized transition obligation	143	178		
Accrued post-retirement benefit costs	$ (180)	$ (136)	$ (60)	$ (47)

For measurement purposes, plan assets were valued as of September 30 for both the Duke Energy U.S. and Westcoast plans.

For Westcoast, the benefit obligation at the beginning of the year 2002 represent balances assumed or acquired in the acquisition of Westcoast as of March 14, 2002.

Assumptions Used for Post-Retirement Benefits Accounting

	Duke Energy U.S.			Westcoast	
	2003	2002	2001	2003	2002
			(percents)		
Determined Benefit Obligations					
Discount rate	6.00	6.75	7.25	6.00	6.50
Salary increase	5.00	5.00	4.94	3.25	3.25
Determined Expense					
Discount rate	6.75	7.25	7.50	6.50	7.25
Salary increase	5.00	5.00	4.94	3.25	3.25
Expected long-term rate of return on plan assets	8.50	9.25	9.25		
Assumed tax rate(a)	39.11	39.60	39.60		

(a) Applicable to the health care portion of funded post-retirement benefits

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For the Duke Energy U.S. plan the discount rate used to determine the pension obligation is based on average investment yields for Moody s AA long-term corporate bonds at the measurement date of September 30.

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.:

		Percentage of Fair Value of Plan Assets at September 30	
Asset Category	**Target Allocation**	**2003**	**2002**
U.S. equity securities	45%	44%	44%
Non-U.S. equity securities	20	20	19
Debt securities	32	35	36
Real estate	3	1	
Cash equivalents / other			1
Total	100%	100%	100%

Duke Energy U.S. plan 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 and excess return over inflation. 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, 2003 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 4.18% for U.S. equities, 1.92% for Non U.S. equities, 2.21% for fixed income securities, and 0.24% for real estate.

Assumed Health Care Cost Trend Rates

	Duke Energy U.S.					
	Not Medicare Eligible		Medicare Eligible		Westcoast	
	2003	2002	2003	2002	2003	2002
Health care cost trend rate assumed for next year	10.50%	10.50%	13.50%	13.50%	10.00%	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	2008	2012	2011	2008	2008

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Sensitivity to Changes in Assumed Health Care Cost Trend Rates Duke Energy U.S. Plan

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(in millions)	
Effect on total service and interest costs	$ 3	$ (3)
Effect on post-retirement benefit obligation	56	(48)

Sensitivity to Changes in Assumed Health Care Cost Trend Rates Westcoast Plans

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(in millions)	
Effect on total service and interest costs	$ 1	$
Effect on post-retirement benefit obligation	10	(9)

See Note 1 for disclosure and discussion of the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

22. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(In millions, except per share data) (as revised, see Note 24)				
2003					
Operating revenues	$ 6,170	$ 5,151	$ 5,557	$ 5,276	$ 22,154
Operating income (loss)	889	676	245	(2,643)	(833)
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) per share (before cumulative effect of change in accounting principle)					
Basic and diluted	$ 0.43	$ 0.46	$ 0.05	$ (2.23)	$ (1.30)

Earnings (loss) per share					
Basic and diluted	$ 0.25	$ 0.46	$ 0.05	$ (2.23)	$ (1.48)
2002					
Operating revenues	$ 3,352	$ 3,595	$ 3,784	$ 5,167	$ 15,898
Operating income	662	896	529	654	2,741
Net income (loss)	382	474	230	(52)	1,034
Earnings (loss) per share					
Basic	$ 0.48	$ 0.57	$ 0.27	$ (0.06)	$ 1.22
Diluted	$ 0.48	$ 0.56	$ 0.27	$ (0.06)	$ 1.22

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 2003 (see Note 12) as well as other reclassifications made in 2003 (see Note 1).

During the first quarter of 2003, Duke Energy recorded charges related to changes in accounting principles of $162 million, net of tax and minority interest (see Note 1).

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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 9), 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 CFTC of $17 million, net of minority interest expense, by DENA (see Note 17).

During the fourth quarter of 2003, Duke Energy recorded the following unusual or infrequently occurring items: impairments on DENA s Southeastern 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 11); charges and impairments of $292 million to complete International Energy s exit from the European market and the divestiture of its Australian assets (see Note 12); a $51 million write-off of an abandoned corporate risk management information system (see Note 11); 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.

During the third quarter of 2002, Duke Energy recorded the following unusual or infrequently occurring items: charges at DENA for the termination of certain turbines on order and the write-down of other uninstalled turbines of $121 million (see Note 11), the partial write-off of site development costs (primarily in California) of $31 million (see Note 11), partial impairment of a merchant plant of $31 million (see Note 11), and demobilization costs related to the deferral of DENA merchant power projects of $12 million; charges of $91 million at International Energy for the write-off of site-development costs and the write-down of uninstalled turbines, primarily related to planned energy plants in Brazil (including amounts classified as discontinued operations, see Note 11 and Note 12); and severance charges of $33 million for work force reductions.

During the fourth quarter of 2002, Duke Energy recorded the following unusual or infrequently occurring items: expenses at Franchised Electric associated with a December 2002 ice storm of $89 million, and a charge of $19 million for settlements with the NCUC and PSCSC (see Note 4); charges at DENA for information technology systems write-offs of $24 million (see Note 11), and demobilization costs related to the deferral of DENA merchant power projects of $10 million; impairment of goodwill at International Energy s European trading and marketing business of $194 million (see Note 9); asset impairments at Field Services of $40 million ($28 million at Duke Energy s 70% share) (see Note 11); and severance charges of $70 million for work force reductions.

23. Subsequent Events (Unaudited)

On March 1, 2004, Duke Capital Corporation, a Delaware corporation which is a wholly owned subsidiary of Duke Energy, announced that it had changed its form of organization from a corporation to a Delaware limited liability company. The change in form of organization was effected by conversion pursuant to Section 266 of the General Corporation Law of the State of Delaware and Section 18-214 of the Delaware Limited Liability Company Act. Pursuant to the conversion, all rights and liabilities of Duke Capital Corporation vested in Duke Capital LLC, a Delaware limited liability company. This conversion will not have any effect on the Duke Energy consolidated results of operations or financial position.

In the second quarter of 2004, DEFS acquired gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips for a total purchase price approximately $80 million, consisting of $74 million in cash and the assumption of approximately $6 million of liabilities.

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On July 2, 2004, Duke Energy realigned certain subsidiaries resulting in all of its wholly owned merchant generation facilities being owned by a newly created entity, Duke Energy Americas, LLC (DEA), a directly wholly owned subsidiary of Duke Capital. DEA and Duke Capital are pass-through entities for US income tax purposes. As a result of these changes, Duke Capital will recognize a federal and state tax expense of approximately $900 million in the third quarter of 2004 from the elimination of the deferred tax assets that existed on its balance sheet prior to the July 2, 2004 reorganization. Correspondingly, Duke Energy, the parent of Duke Capital, will reflect, through consolidation, the elimination of the $900 million deferred tax asset at Duke Capital and the creation of a deferred tax asset of approximately $900 million on its balance sheet. Duke Energy will additionally recognize an approximate $45 million income tax benefit and corresponding deferred tax asset as a result of restating its deferred taxes to reflect a change in state tax rates. In future periods, as these deferred tax assets are converted into cash due to the realization of certain tax losses, Duke Energy intends to infuse the related cash flows back into Duke Capital. Most of these cash benefits result from tax losses arising from the sales of DENA s Southeastern U.S. generation assets and the Moapa facility.

Asset Sales

In January 2004, Duke Energy, through its wholly owned subsidiary Duke Energy Royal, LLC, agreed to sell its interest in six energy service agreements and Duke Energy Huntington Beach, LLC. In February 2004, DEFS entered into a purchase and sale agreement to sell certain gas gathering and processing plant assets in West Texas. Also in February 2004, DEM sold its 15-percent ownership interest in Caribbean Nitrogen Company. Additionally, during the first and second quarter of 2004, DENA sold turbines and surplus equipment. In total, all of these transactions resulted in cash proceeds of approximately $209 million and a net gain of approximately $14 million.

During the first and second quarter of 2004, DETM sold certain physical power contracts in which it held a liability position. As part of the sale, DETM paid a third party an immaterial amount, which approximated the carrying value of the contracts at December 31, 2003.

In the first quarter of 2004, Duke Energy recorded a $238 million after-tax gain related to International Energy s Asia Pacific power generation and natural transmission businesses. The estimated fair value, less costs to sell was classified as held for sale as of December 31, 2003. The gain recorded in the first quarter of 2004 restores the loss recorded during the fourth quarter of 2003. The December 31, 2003 estimated fair value was based upon third-party bids received by International Energy. During the first quarter, Duke Energy determined that it was likely a bid in excess of the originally determined fair value would be accepted. In April 2004, Duke Energy completed the sale of the Asia-Pacific businesses to Alinta Ltd. for a gross sales price of approximately $1.2 billion. This resulted in recording an additional $40 million after-tax gain in the second quarter. Duke Energy received approximately $390 million of cash proceeds, net of debt repayment of approximately $840 million of debt retired (as a non-cash financing activity) as part of the Asia-Pacific operations. The $840 million does not include approximately $50 million of Australian debt which has been placed in trust and fully funded in connection with the closing of the sale transaction and will be repaid in September 2004. This trust is included in the Consolidated Financial Statements as Duke Energy is the primary beneficiary of the trust and, therefore, is required to consolidate the trust under provisions of FIN 46. The Asia-Pacific debt had been classified as Current and Non-Current Liabilities Associated with Assets Held for Sale on the December 31, 2003 Consolidated Balance Sheet. All gains related to this transaction and the results of operations for these assets are included in Net Gain (Loss) on Dispositions, net of tax, within Discontinued Operations, in the 2004 Consolidated Statements of Operations.

On May 4, 2004 Duke Energy announced the sale of its merchant generation business in the southeastern United States to KGen Partners LLC (KGen). The sale transaction has obtained all required regulatory approvals

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Notes To Consolidated Financial Statements Continued

and consents and closed on August 5, 2004. This transaction resulted in a cumulative pre-tax loss of approximately $367 million, of which approximately $360 million was recognized in the first quarter of 2004 to reduce the carrying value of those assets to their estimated fair values, while the remaining amount of the loss will be recognized by Duke Energy in the third quarter of 2004. Subsequent to the closing of the transaction, DENA will continue to provide certain transitional services and operating and maintenance services for the sold assets, including potential exercise of limited plant dispatch rights for a period not to exceed six months form the date of August 5, 2004. DENA anticipates recognizing the sale transaction in the third quarter of 2004, pending resolution of certain continuing involvement provisions.

In conjunction with the sale of DENA s southeastern assets to KGen, Duke Energy 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 its Murray facility to Georgia Power. Duke Energy is the primary obligor to the letter of credit provider, but KGen has an obligation to reimburse Duke Energy for any payments made by it under the letter of credit, as well as expenses incurred by Duke Energy in connection with the letter of credit. Duke Energy will operate the Murray facility under an operation and maintenance agreement with a KGen subsidiary.

As disclosed in Note 12 to the Consolidated Financial Statements, Subsequent Events, in Duke Energy s Form 10-Q for June 30, 2003, Duke Energy announced the sale of a 25% undivided interest in the Duke Energy Vermillion facility. In May 2004, the sale of the 25% undivided interest in the Vermillion facility was completed for approximately $44 million. A loss on the sale of approximately $18 million was recorded in the third quarter of 2003. Duke Energy will continue to own the remaining 75% interest in the facility.

In May 2004, Duke Energy reached an agreement to sell its 30% equity interest in Compañia de Nitrógeno de Cantarell, S.A. de C.V., nitrogen production and delivery facility in the Bay of Campeche, Gulf of Mexico for approximately $60 million. Duke Energy recorded a non-cash charge of $13 million to Operation, Maintenance and Other expenses on the Consolidated Statements of Operations in the first quarter of 2004 in anticipation of this sale. The sale is expected to close in the third quarter of 2004.

In the second quarter of 2004, Duke Energy announced an agreement to sell one of DENA s deferred facilities, Moapa, to Nevada Power Company for approximately $182 million in cash, with closing expected during the fourth quarter of 2004 pending regulatory approvals. The Moapa asset was classified as held for sale in the June 30, 2004 Consolidated Balance Sheet. This facility will not be reported in Discontinued Operations as, among other considerations, the facility never entered into operations and has no associated historical operating revenues or costs.

Debt and Financing Related Matters

In March 2004, Duke Energy redeemed the entire issue of 7.20% Duke Energy debt to an affiliate due 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 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, Duke Capital purchased $101 million of its outstanding notes in the open market. These purchases included $49 million of Duke Capital 5.50% senior notes due March 1, 2014 and $52 million of Duke Capital 4.37% senior notes due March 1, 2009. The securities were redeemed at the then current market price plus accrued interest.

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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

In May 2004, Duke Energy redeemed Duke Energy Series C 6.60% Senior Notes due 2038, at a $200 million face value. As the securities were redeemed at par, security holders received $25 per preferred security held, plus accrued interest to 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. Duke Energy issued 35,000,000 Equity Units in March 2001 at $25 per unit. 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. The rate was 0.6414 shares of stock per Equity Unit.

In June 2004, Westcoast Energy, Inc. 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 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 each note held, plus accrued and unpaid distributions to the redemption date.

In July 2004, Duke Energy announced that on August 31, 2004, it will redeem the entire issue of Duke Capital Financing Trust III 8 $^{3}/8$% Trust Preferred Securities due August 31, 2029 with a face value of $250 million. As the securities are being redeemed at par, security holders will receive $25 per preferred security held, plus accrued and unpaid distributions to the redemption date. Additionally, Duke Energy plans to remarket $750 million of its 4.32% senior notes, due 2006, underlying its 8.00% Equity Units on August 11, 2004. Proceeds from the remarketed notes will be held by a collateral agent and used to purchase U.S. Treasury securities to satisfy the forward stock purchase contract component of the Equity Units in November 2004.

Regulatory Matters

Bulk Power Marketing Profit Sharing. On June 9, 2004, the NCUC approved Duke Energy s proposal to share an amount equal to 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 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.

On June 29, 2004, Duke Energy informed the PSCSC that it would no longer include BPM Profits in the calculating of its South Carolina retail jurisdictional rate of return for its quarterly reports to the PSCSC. Duke Energy proposed to establish an entity to receive 50% of the South Carolina allocable share of the BPM Profits to support public assistance programs, education programs to promote economic development funding, and grants to promote the attraction and retention of industrial customers. 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

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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

case. The 2004 year-to-date total of $27 million of shared profits was recorded as a $14 million decrease to revenues (for the portion related to reduced industrial customers rates) and a $13 million charge to expenses (for the portion related to donations to charitable, educational and economic development programs in North Carolina and South Carolina) in the second quarter of 2004.

For information on additional subsequent events related to debt and other financing matters refer to Note 14. For information on additional subsequent events related to Regulatory Matters refer to Note 4. For information on subsequent events related to litigation and contingencies refer to Note 17 Litigation. For information on subsequent events related to the MOX guarantee, refer to Note 18.

24. Revisions to Classifications in the Consolidated Statements of Cash Flows, Statements of Operations and Balance Sheets

In 2004, Duke Energy elected to change its business segments to present Crescent as separate segment. Following with this change, management determined that revisions were required to revise certain financial statement line items related to Crescent s activities. Prior to and including the quarter ending March 31, 2004, the cash outflows related to Crescent s purchases of commercial, residential and multi-family real estate were presented as a component of the capital expenditures within cash flows from investing activities. The proceeds from the sales of these properties, as well as proceeds from the sales of legacy land were shown as part of the reconciliation of net income to net cash flows from operating activities, and thus included in cash flows from operating activities.

Duke Energy has since determined that the cash inflows and outflows from Crescent s purchases and sales of commercial and multi-family properties, as well as proceeds from the sales of legacy land should have been presented as a component of cash flows from investing activities. All cash inflows and outflows related to Crescent s residential properties should have been presented within cash flows from operating activities.

Prior to, and including the quarter ending March 31, 2004, all sales of real estate by Crescent were reported in revenues and the cost basis for all properties sold was included in operation and maintenance expense in the Consolidated Statements of Operations. Consistent with the change in presentation noted above for the Consolidated Statements of Cash Flows, Duke Energy has determined that amounts related to the purchases and sales of commercial and multi-family real estate, as well as the sales proceeds and underlying cost of legacy land should have been presented in the Consolidated Statements of Operations as Gains on Sales of Investments in Commercial and Multi-Family Real Estate, rather than presented in revenues and operation and maintenance expenses.

Crescent s real estate investments were previously classified in Inventory and Property, Plant and Equipment on the Consolidated Balance Sheets. Going forward, these amounts will be classified into a non-current asset line, Investments in Residential, Commercial and Multi-Family Real Estate, net. Accordingly, this revised presentation has been reflected in the accompanying Consolidated Balance Sheets.

Additionally, operating revenues and operating expenses have also been revised to reflect additional discontinued operations. See Note 12 for additional information.

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DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements Continued

The following shows the reclassifications made to the accompanying financial statements to reflect the items discussed above.

Reclassification of Cash flows from Operating and Investing Activities (in millions)

	For the years ended December 31,		
	2003	2002	2001
Net cash provided by operating activities, as previously reported	$ 3,929	$ 4,547	$ 4,357
Reclassifications	(510)	(348)	(608)
Net cash provided by operating activities, as revised	$ 3,419	$ 4,199	$ 3,749
Net cash used in investing activities, as previously reported	$ (931)	$ (6,809)	$ (6,043)
Reclassifications	510	348	608
Net cash used in investing activities, as revised	$ (421)	$ (6,461)	$ (5,435)

Reclassification of Operating Revenues and Operating Expenses (in millions)

	For the years ended December 31,		
	2003	2002	2001
Total operating revenues, as previously reported	$ 22,410	$ 16,122	$ 18,324
Reclassifications	(256)	(224)	(378)
Total operating revenues, as revised	$ 22,154	$ 15,898	$ 17,946
Total operating expenses, as previously reported	$ 23,044	$ 13,413	$ 14,639
Reclassifications	(172)	(118)	(272)
Total operating expenses, as revised	$ 22,872	$ 13,295	$ 14,367
Gains on sales of investments in commercial and multi-family real estate, as previously reported	$	$	$
Reclassifications	84	106	106

Total gains on sales of investments in commercial and multi-family real estate, as revised	$ 84	$ 106	$ 106

Reclassification of Balance Sheets (in millions)

	For the years ended December 31,	
	2003	**2002**
Inventory, as previously Reported	$ 1,156	$ 1,134
Reclassifications to Investments in residential, commercial and multi-family real estate, net	(215)	(163)
Inventory, as revised	$ 941	$ 971
Net Property, Plant and Equipment, as previously reported	$ 34,986	$ 37,379
Reclassifications to Investments in residential, commercial and multi-family real estate, net	(1,116)	(1,277)
Net Property, Plant and Equipment, as revised	$ 33,870	$ 36,102
Investments in residential, commercial and multifamily real estate, as previously reported	$	$
Reclassifications	1,331	1,440
Investments in residential, commercial and multifamily real estate, as revised	$ 1,331	$ 1,440

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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, 2003:					
Injuries and damages	$ 367	$ 1	$ 4	$ 73	$ 299
Allowance for doubtful accounts	349	65	16	150	280
Other(b)	513	183	18	299	415
	$ 1,229	$ 249	$ 38	$ 522	$ 994
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
December 31, 2001:					
Injuries and damages	$ 531	$ 31	$ 11	$ 114	$ 459
Allowance for doubtful accounts	200	160	4	99	265
Other(b)	377	201	84	256	406
	$ 1,108	$ 392	$ 99(d)	$ 469	$ 1,130

(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 North Carolina Utilities Commission and the Public Service Commission of South Carolina (see Note 4 to the Consolidated Financial Statements, Regulatory Matters Franchised Electric).
(d) Principally reserves for construction costs, and litigation and other reserves assumed in business acquisitions.

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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, 2003 and 2002, 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, 2003. 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 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, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. 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. 133, Accounting for Derivative Instruments and Hedging Activities, as of January 1, 2001. As discussed in Note 1 and Note 9, 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 3, effective January 1, 2004, Duke Energy realigned its segments for financial reporting purposes.

As discussed in Note 24, the accompanying consolidated financial statements have been revised.

/s/ DELOITTE & TOUCHE LLP

Deloitte & Touche LLP

Charlotte, North Carolina

March 15, 2004

(August 9, 2004 as to Notes 3, 12, 24 and

the Litigation section of Note 17)

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RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Duke Energy Corporation (Duke Energy) are prepared by management, who are responsible for their integrity and objectivity. The statements are prepared in conformity with generally accepted accounting principles in all material respects and necessarily include judgments and estimates of the expected effects of events and transactions that are currently being reported.

Duke Energy s system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed according to management s authorization. Internal accounting controls also provide reasonable assurance that transactions are recorded properly, so that financial statements can be prepared according to generally accepted accounting principles. In addition, accounting controls provide reasonable assurance that errors or irregularities which could be material to the financial statements are prevented or are detected by employees within a timely period as they perform their assigned functions. Duke Energy s accounting controls are continually reviewed for effectiveness. In addition, written policies, standards and procedures, and an internal audit program augment Duke Energy s accounting controls.

The Board of Directors pursues its oversight role for the financial statements through the audit committee, which is composed entirely of independent directors who are not employees of Duke Energy. The audit committee meets with management and internal auditors periodically to review accounting control issues and to monitor each group s discharge of its responsibilities. The audit committee also meets periodically with Duke Energy s independent registered public accounting firm, Deloitte & Touche LLP. The registered public accounting firm has free access to the audit committee and the Board of Directors to discuss internal accounting control, auditing and financial reporting matters without the presence of management.

/s/ Keith G. Butler

Keith G. Butler

Vice President and Controller

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

None.

Item 9A. 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.

In performing its audit of Duke Energy s Consolidated Financial Statements for the year ended December 31, 2003, Duke Energy s independent registered public accounting firm, Deloitte & Touche LLP (Deloitte), noted certain matters involving Duke Energy s internal controls that it considered to be a reportable condition under the standards established by the Public Accounting Oversight Board (United States). A reportable condition involves matters relating to significant deficiencies in the design or operation of internal controls that, in Deloitte s judgment, could adversely affect Duke Energy s ability to record, process, summarize and report financial data consistent with the assertions of management on the financial statements. The reportable condition noted by Deloitte related to the sufficiency of supporting documentation and transaction analysis, the application of generally accepted accounting principles, and the treatment of intercompany transactions during the consolidation process. The reportable condition was not considered by Deloitte to be a material weakness under the applicable auditing standards and had no material affect on Duke Energy s financial statements. Management has discussed the reportable condition with the Duke Energy Audit Committee and is implementing procedures and controls to address the identified conditions and enhance the reliability of Duke Energy s internal control procedures.

Management has concluded that the Disclosure Controls Evaluation identified no changes in Duke Energy s internal control over financial reporting that occurred during the fourth quarter of 2003 that have materially affected, or are reasonably likely to materially affect, Duke Energy s internal control over financial reporting.

In 2004, Duke Energy elected to change its business segments to present Crescent Resources, LLC as a separate segment. In connection with this change, management determined that revisions were required to the presentation of the Consolidated Statements of Cash Flows, Statements of Operations and Balance Sheets related to its real estate activities. Management evaluated such revisions and determined that while this matter represents a significant deficiency, it did not represent a material weakness and that Duke Energy s disclosure controls are effective.

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PART III.

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 2004 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 employees of Duke Energy and Duke Energy s consolidated subsidiaries. The Code of Business Ethics is posted on Duke Energy s Internet Web site: *http://www.duke-energy.com/investors/corporate/ethics.htm* and is available in print to any shareholder who requests it. In satisfaction of the disclosure requirements of Item 10 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.

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 is posted on Duke Energy s Internet Web site: *http://www.duke-energy.com/investors/corporate.htm* 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, and the charters of each of the committees of Duke Energy s board of directors, are posted on Duke Energy s Internet Web site: *http://www.duke-energy.com/investors/corporate.htm* and are available in print to any shareholder who requests it.

Item 11. Executive Compensation.

See Compensation and Information on the Board of Directors Compensation of Directors in the Proxy Statement relating to Duke Energy s 2004 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 2004 annual meeting of shareholders, incorporated herein by reference.

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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 for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	30,351,568(2)	$ 29.28	24,074,722(3)
Equity compensation plans not approved by security holders	None	None	None
Total	30,351,568	$ 29.28	24,074,722

(1) Duke Energy has not granted any warrants or rights under any equity compensation plans. Amounts do not include 2,064,156 outstanding options with a weighted average exercise price of $22.8712 assumed in connection with various mergers and acquisitions.
(2) Does not include 3,286,851 shares of Duke Energy common stock to be issued upon vesting of phantom stock and performance share awards outstanding as of December 31, 2003.
(3) Includes 7,723,811 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.

See Information on the Board of Directors Compensation Committee Interlocks and Insider Participation in the Proxy Statement relating to Duke Energy s 2004 annual meeting of shareholders, incorporated herein by reference.

Item 14. Principal Accounting Fees and Services.

See Other Information Fees Paid to Independent Auditors in the Proxy Statement relating to Duke Energy s 2004 annual meeting of shareholders, incorporated herein by reference.

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PART IV.

Item 15. Exhibits, Financial Statement Schedule, and Reports on Form 8-K.

(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, 2003, 2002 and 2001, as revised

Consolidated Statements of Cash Flows for the Years Ended December 31, 2003, 2002 and 2001, as revised

Consolidated Balance Sheets as of December 31, 2003 and 2002, as revised

Consolidated Statements of Common Stockholders Equity and Comprehensive Income (Loss) for
the Years ended December 31, 2003, 2002 and 2001

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, 2003, 2002 and 2001

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.

(b) Reports on Form 8-K

A Current Report on Form 8-K furnished on October 30, 2003 contained disclosures under Item 7, Financial Statements and Exhibits, and Item 12, Results of Operations and Financial Condition.

(c) Exhibits See Exhibit Index immediately following the signature page.

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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: August 9, 2004

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:
Paul M. Anderson

G. Alex Bernhardt, Sr.

William T. Esrey

Ann Maynard Gray

George Dean Johnson, Jr.

A. Max Lennon

Leo E. Linbeck, Jr.

James G. Martin

Michael E.J. Phelps

James T. Rhodes

Date: August 9, 2004

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

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EXHIBIT INDEX

Exhibits filed with the original Form 10-K on March 15, 2004 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 (**). Exhibits filed herewith are designated by a triple 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 Duke Energy Corporation 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 (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).
3-3	Articles of Amendment to Restated Articles of Incorporation of registrant (filed with Form 10-Q of the registrant for the quarter ended March 31, 2002, File No. 1-4928, as Exhibit 3).
3-4	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).
10-1**	Directors Charitable Giving Program (filed with Form 10-K 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.
*10-1.2**	Amendment to Directors Charitable Giving Program dated July 28, 1997.
*10-1.3**	Amendment to Directors Charitable Giving Program dated February 18, 1998.
10-2**	Estate Conservation Plan (filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, as Exhibit 10-R).
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).
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).
10-5**	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.
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).
10-8**	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 the registrant and certain key executives (filed with Form 10-K of the registrant for the year ended December 31, 1999, as Exhibit 10-BB).

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Exhibit Number	
10-10**	Form of Change in Control Agreement between the registrant and certain key executives (filedwith Form 10-K of the registrant for the year ended December 31, 1999, as Exhibit 10-CC).
10-11	Contribution Agreement by and among Phillips Petroleum Company, Duke Energy Corporation and Duke Energy Field Services LLC, dated as of December 16, 1999 (filed as Exhibit 2.1 to Form 8-K of the registrant, filed December 30, 1999).
10-12	Governance Agreement by and among Phillips Petroleum Company, Duke Energy Corporation and Duke Energy Field Services LLC, dated as of December 16, 1999 (filed as Exhibit 2.2 to Form 8-K of the registrant, filed December 30, 1999).
10-13	First Amendment to Contribution and Governance Agreement dated as of March 23, 2000 among Phillips Petroleum Company, Duke Energy Corporation and Duke Energy Field Services, LLC (incorporated by reference to Exhibit 10.7 (b) to Registration Statement on Form S-1/A (Registration No. 333-32502) of Duke Energy Field Services Corporation, filed on March 27, 2000).
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 (incorporated by reference to Exhibit 10.10 to Registration Statement on Form S-1/A (Registration No. 333-32502) of Duke Energy Field Services Corporation, filed on May 4, 2000).
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).
10-16	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).
10-17	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 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.
*10-18.1**	First Amendment to Employment Agreement dated March 9, 2004 between Paul M. Anderson and Duke Energy Corporation.
*10-19**	Supplemental Compensation Agreement dated June 17, 1997 between Duke Power Company and Dr. Ruth G. Shaw.
*10-20**	Separation Agreement and General Release dated January 30, 2004 between Duke Energy Corporation and Robert Brace.
*10-21**	Letter agreement dated January 28, 2004 between Duke Energy Corporation and Richard W. Blackburn.
*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.
***12	Computation of Ratio of Earnings to Fixed Charges.

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Exhibit Number	
*21	List of Subsidiaries.
***23(a)	Consent of Independent Registered Public Accounting Firm.
*24(a)	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(b)	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.