VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

March 31, 2003

Director of Nuclear Reactor Regulation
United States Nuclear Regulatory Commission
Washington, DC 20555-0001

Serial No.: 03-196
NLOS/MM
Docket Nos.: 50-280/281
50-338/339
72-2/16
License Nos.: DPR-32/37
NPF-4/7
SNM-2501/2507

Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY (DOMINION)
SURRY POWER STATION AND ISFSI
NORTH ANNA POWER STATION AND ISFSI
ANNUAL REPORTING OF FINANCIAL INFORMATION

Pursuant to 10 CFR 140.21(e) regarding guarantees of payment of deferred premiums for power reactors, we are providing the following financial information:

1. Comparative Statements of Income for the three months ended December 31, 2002 and 2001.

2. Internal cash flow projection for calendar year 2003 with certification by an officer of the Company.

3. Statement ensuring availability of funds for payment of retrospective premiums without curtailment of required nuclear construction expenditures.

4. A copy of the Annual Report to Securities and Exchange Commission on Form 10-K for 2002.

M004

In accordance with 10 CFR 140.7, a check for $1,000 was submitted to the NRC on November 8, 2002, as the associated minimum fee for the period November 15, 2002 through November 14, 2003.

This financial information is also being provided to address the annual reporting requirement for Independent Spent Fuel Storage Installations pursuant to 10 CFR 72.80(b).

Very truly yours,

Eugene S. Grecheck
Vice President – Nuclear Support Services

Enclosures

cc: U. S. Nuclear Regulatory Commission
Region II
Sam Nunn Atlanta Federal Center
61 Forsyth St., SW, Suite 23 T85
Atlanta, GA 30303-8931

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Mr. M. J. Virgilio, Director
Office of Nuclear Material Safety and Safeguards
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Mr. R. A. Musser
NRC Senior Resident Inspector
Surry Power Station

Mr. M. J. Morgan
NRC Senior Resident Inspector
North Anna Power Station

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	Quarter Ended December 31, 2002	2001
	(millions)	
Operating Revenue	$1,126	$1,101
Operating Expenses		
Electric fuel and energy purchases, net	325	276
Purchased electric capacity	174	164
Restructuring costs	(7)	48
Other operations and maintenance	221	332
Depreciation and amortization	122	135
Other taxes	38	48
Total operating expenses	873	1,003
Income from operations	253	98
Other income	2	11
Interest and related charges:		
Interest expense	64	68
Distributions—preferred securities of subsidiary trust	7	3
Total interest and related charges	71	71
Income before income taxes	184	38
Income taxes	55	17
Net income	129	21
Preferred dividends	2	4
Balance available for common stock	$ 127	$ 17

VIRGINIA ELECTRIC AND POWER COMPANY
2003 ESTIMATED INTERNAL CASH FLOW
(Millions of Dollars)

	January through March	April through June	July through September	October through December	Estimated 2003 Total
Cash receipts	$ 1,244	$ 1,229	$ 1,543	$ 1,228	$ 5,244
Less:					
Cash for operations	708	718	783	703	2,912
Taxes	166	157	231	160	715
Interest	69	73	74	75	290
Dividends	129	116	218	113	576
Decommissioning trust	9	9	9	9	36
Changes in working capital/other	(170)	(41)	2	(92)	(300)
Total cash flow (1)	$ 332	$ 197	$ 226	$ 260	$ 1,015

(1) Before financing and construction requirements

VIRGINIA ELECTRIC AND POWER COMPANY
CERTIFICATE

I, the undersigned, Simon Hodges, do hereby certify, pursuant to the guarantee requirements set forth in the Commission's letter dated June 15, 1977, that the cash flow projection for 2003, provided herewith, is based on the best available information known at this time and is a reasonably accurate projection of the company's 2003 cash flow.

Simon Hodges
Vice President – Financial Planning

NOTARIAL SEAL

Commonwealth of Virginia
City of Richmond

I, Brenda G. Long, certify that Simon Hodges is Vice President – Financial Planning for Dominion, and such certificate was signed on March 20, 2003

Brenda G. Long

My commission expires: August 31, 2003

VIRGINIA ELECTRIC AND POWER COMPANY
STATEMENT

Based on the company's 2003 approved budget, the company estimates that 2003 construction and nuclear fuel expenditures (exclusive of Allowance for Funds Used During Construction) to be $995 million Maturity of securities in 2003 will total $360 million. It is expected that approximately $1,015 million will be obtained from internal sources. The remaining $340 million of capital requirements will be obtained by a combination of sales of securities and short-term borrowings The company is reasonably assured that, based on the best available cash flow projections which are provided herewith, curtailment of capital expenditures for required nuclear programs would not be required to cover the Price-Anderson maximum retrospective premium assessment for a single incident of $352 million ($88 million, including a 3 percent insurance premium tax for Virginia, for each of the four reactors owned by the Company with assessments not to exceed $10 million per reactor per year) currently in force.

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)
☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2002

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 1-2255

VIRGINIA ELECTRIC AND POWER COMPANY
(Exact name of registrant as specified in its charter)

Virginia (State or other jurisdiction of incorporation or organization)	54-0418825 (I.R.S. Employer Identification No.)
701 East Cary Street Richmond, Virginia (Address of principal executive offices)	23219 (Zip Code)

(804) 819-2000
(Registrant's telephone number)

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

Title of Each Class	Name of Each Exchange on Which Registered
Preferred Stock (cumulative), $100 par value, $5.00 dividend	New York Stock Exchange
7.375% Trust Preferred Securities (cumulative), $25 par value	New York Stock Exchange
7 15% Senior Notes due 2038	New York Stock Exchange
6 70% Senior Notes due 2009	New York Stock Exchange

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

None

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

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

Indicate by check mark whether the registrant is an accelerated filer. Yes ☐ No ☒

The aggregate market value of the voting stock held by non-affiliates as of February 28, 2003, was zero.

As of February 28, 2003, there were issued and outstanding 177,932 shares of the registrant's common stock, without par value, all of which were held, beneficially and of record, by Dominion Resources, Inc.

DOCUMENTS INCORPORATED BY REFERENCE.

None

Virginia Electric and Power Company.

Part I

Item 1. Business

The Company

Virginia Electric and Power Company (the Company) is a regulated public utility that generates, transmits and distributes power for sale in Virginia and northeastern North Carolina. In Virginia, the Company conducts business under the name "Dominion Virginia Power." The Virginia service area comprises about 65 percent of Virginia's total land area, but accounts for over 80 percent of its population. In North Carolina, the Company conducts business under the name "Dominion North Carolina Power" and serves retail customers located in the northeastern region of the state, excluding certain municipalities. In addition, the Company sells electricity at wholesale to rural electric cooperatives, power marketers, municipalities and other utilities. Within this document, "the Company" refers to the entirety of Virginia Electric and Power Company, including our Virginia and North Carolina operations and all of its subsidiaries.

All of the Company's common stock is owned by its parent company, Dominion Resources, Inc. (Dominion), a fully integrated gas and electric holding company.

Operating Segments

The Company manages its business through two principal segments: Energy and Delivery.

Energy—Energy manages the Company's portfolio of generating facilities and power purchase agreements and its energy trading and marketing, hedging and arbitrage activities. Effective January 1, 2003, the Company's electric transmission operations became a part of the Energy segment.

Delivery—Delivery manages the Company's electric distribution and transmission systems as well as customer service. Effective January 1, 2003, the Company's electric transmission operations became a part of the Energy segment.

The majority of the Company's revenue is provided through bundled rate tariffs. This revenue is allocated between the Energy and Delivery segments for internal reporting purposes and discussion in this document. While the Company manages its daily operations as described above, its assets remain wholly owned and operated by the Company. For additional financial information on business segments, see Note 26 to the Consolidated Financial Statements.

As of December 31, 2002, the Company had approximately 7,600 full-time employees. Approximately 3,600 employees are subject to collective bargaining agreements.

Virginia Electric and Power Company was incorporated in 1909 as a Virginia public service corporation. Its principal office is located at 701 East Cary Street, Richmond, Virginia 23219-3932. The telephone number is (804) 819-2000.

Seasonality

Sales of electricity in the Delivery segment typically vary seasonally based on increased demand for electricity by residential and commercial customers for cooling and heating use based on changes in temperature. The Energy segment is also impacted by seasonal changes in the prices of commodities, primarily electricity and natural gas, that it actively markets and trades.

Competition

Various factors are currently affecting the electric utility industry, including increasing competition and related regulatory changes, costs to comply with environmental regulations, and the potential for new business opportunities outside of traditional rate-regulated operations. To meet the challenges of this new competitive environment, the Company continues to consider new business opportunities, particularly those which allow the Company to use its existing expertise and resources.

The Virginia Electric Utility Restructuring Act (the Virginia Restructuring Act) was enacted in 1999 and established a plan to restructure Virginia's electric utility industry and provide for the phase-in of choice for retail customers from January 1, 2002 through January 1, 2004. As ordered by the Virginia State Corporation Commission (Virginia Commission), the Company made retail choice available for all of its Virginia regulated electric customers as of January 1, 2003.

Under the Virginia Restructuring Act, the generation portion of the Company's Virginia jurisdictional operations is no longer subject to cost-based rate regulation effective January 1, 2002. Base rates (excluding fuel costs and certain other allowable adjustments) are capped and will remain unchanged until July 2007, unless modified or terminated sooner, as provided by the Virginia Restructuring Act. Under the Virginia Restructuring Act, the Company may request a termination of the capped rates at any time after January 1, 2004, and the Virginia Commission may grant the Company's request to terminate capped rates, if it finds that a competitive generation services market exists in the Company's service area. Recovery of generation-related costs will continue to be provided through capped rates and a wires charge. A wires charge, where applicable, will be assessed to those customers opting for alternative suppliers. The Virginia Restructuring Act also requires the Company to join or establish a regional transmission organization (RTO), phase-in retail choice beginning January 1, 2002, and functionally separate its electric generation from its electric transmission and distribution operations.

Recently, the Virginia Commission recommended that state policymakers decide promptly whether to proceed with or delay implementation of the Virginia Restructuring Act, in light of recent developments impacting electric industry restructuring in Virginia, including the Federal Energy Regulatory Commission's (FERC) issuance of a notice of proposed rule making on Standard Market Design. Legislation that would delay entry into a RTO until on or after July 1, 2004 was approved by the Virginia General Assembly in February 2003 and is now awaiting action by the Governor. The proposed legislation also would require the Company to file an application with the Virginia Commission by July 1, 2003 to join a RTO. Subject to Virginia Commission approval, the Company would be required to transfer management and control of its transmission assets to a RTO by January 1, 2005.

For additional information on electric deregulation in Virginia, see *Electric Deregulation Legislation* in *Future Issues and Outlook* in Item 7. Management's Discussion and Analysis and Results of Operations (MD&A).

In North Carolina, regulators and legislators continue to explore the issues related to electric industry restructuring, the development of a competitive, wholesale market and retail competition. However, to date, there has been no significant activity.

The Company plans to continue to participate actively in both the legislative and regulatory processes to ensure an orderly transition from a regulated environment.

Regulation

General

The Company is subject to regulation by the Virginia Commission, the North Carolina Utilities Commission (North Carolina Commission), Securities and Exchange Commission (SEC), FERC, the Environmental Protection Agency (EPA), Department of Energy (DOE), the Nuclear Regulatory Commission (NRC), the Army Corps of Engineers, and other federal, state and local authorities.

State Regulation

In Virginia, the Company's retail service is subject to regulation by the Virginia Commission. The Virginia Commission approved a Virginia fuel factor of 1.613 cents per kWh in effect through December 31, 2003.

In North Carolina, retail service is subject to cost of service regulation by the North Carolina Commission. In connection with the North Carolina Commission approval of Dominion's acquisition of Consolidated Natural Gas Company (CNG), the Company agreed not to request an increase in North Carolina retail electric base rates until 2006, except for certain events that would have a significant financial impact on the Company. Fuel rates are still subject to change under the annual fuel cost adjustment proceedings. The North Carolina Commission has approved a fuel factor of 1.402 cents per kWh, effective January 1, 2003.

The Company holds certificates of public convenience and necessity authorizing it to construct and operate its electric facilities now in operation and to sell electricity to customers. However, it may not construct or incur financial commitments for construction of any substantial generating facilities or large capacity transmission lines without the prior approval of various state and federal government agencies.

In August 2002, the Virginia Commission adopted rules relating to competitive electric metering services and consolidated billing by competitive suppliers. The Company must provide its Virginia electric customers with access to meter functionality and interval meter data beginning January 1, 2003 and implement consolidated billing by competitive suppliers no later than July 1, 2003.

For additional information on deregulation in the electric industry, the Virginia Restructuring Act and current rate matters, see above in *Competition* and *Future Issues and Outlook* in MD&A.

Public Utility Holding Company Act of 1935

When Dominion completed the acquisition of CNG in January 2000, it became a registered public utility holding company under the 1935 Act. The 1935 Act and related regulations issued by the SEC govern the activities of Dominion and its subsidiaries, including the Company, with respect to the issuance and acquisition of securities, acquisition and sale of utility assets, certain transactions among affiliates engaging in business activities not directly related to the utility or energy business and other matters. The Company's activities in these areas may also be regulated at the state level by the Virginia Commission and the North Carolina Commission. In some cases, the SEC's rules under the 1935 Act provide that the obtaining of state approvals will suffice for the 1935 Act purposes also, subject to the fulfillment of certain post-transaction reporting requirements.

Federal Energy Regulatory Commission

Under the Federal Power Act, FERC regulates wholesale sales of electricity and transmission of electricity in interstate commerce by public utilities. The Company sells electricity in the wholesale market under its market-based sales tariff authorized by FERC but has agreed not to make wholesale power sales under this tariff to loads located within its service territory. For additional discussion on this matter, see *Wholesale Competition* in *Future Issues and Outlook* in MD&A.

The Virginia Restructuring Act requires that the Company join a RTO, and FERC encourages RTO formation as a means to foster wholesale market formation. FERC Order No. 2000 requires each public utility that owns or operates transmission facilities to make certain filings with respect to RTO formation, but will rely on voluntary formation of RTOs to advance its energy policies. By joining a RTO, the Company would transfer operational control of its transmission assets to a RTO, a third party.

In September 2002, the Company and PJM Interconnection, LLC (PJM) entered into the PJM South Implementation Agreement. The agreement provides that, subject to regulatory approval and certain provisions, the Company will become a member of PJM, transfer functional control of its electric transmission facilities to PJM for inclusion in a new PJM South Region, integrate its control area into the PJM energy markets and otherwise facilitate the establishment and operation of PJM as the RTO with respect to the Company's transmission facilities. The agreement also contemplates additional agreements and transmission tariff provisions to be negotiated by the parties and allocates costs of implementation of the agreement among the parties.

The Company intends to file for FERC approval to join PJM in the future. The Company will also seek authorization from the Virginia Commission and the North Carolina Commission to become a member of PJM at that time. The Company will incur integration and operating costs associated with joining a RTO. The Company has deferred certain of those costs for future recovery and is giving further consideration to seeking regulatory approval to defer the balance of such costs.

For additional discussion on this matter, see *Regional Transmission Organization* in *Future Issues and Outlook* in MD&A.

Legislation that would delay entry into a RTO until on or after July 1, 2004 was approved by the Virginia General Assembly in February 2003 and is now awaiting action by the Governor. The proposed legislation also would require the Company to file an application with the Virginia Commission by July 1, 2003 to join a RTO. Subject to Virginia Commission approval, the Company would be required to transfer management and control of its transmission assets to a RTO by January 1, 2005.

In the spring of 2003, FERC expects to issue new rules governing standards of conduct between interstate electric transmission, gas transportation and storage providers and their energy related affiliates. One goal of FERC is to eliminate the separate code of conduct regulations for natural gas pipelines and electric transmission utilities and replace these requirements with uniform standards applicable to interstate "Transmission Providers" of both natural gas and electricity. For additional discussion on this matter, see *FERC Policy Developments* in *Future Issues and Outlook* in MD&A.

Environmental Matters

Each operating segment of the Company faces substantial regulation and compliance costs with respect to environmental matters. For discussion of significant aspects of these matters, including current and planned capital expenditures relating to environmental compliance, see *Environmental Matters* in *Future Issues and Outlook* in MD&A. Additional information can also be found in Item 3. Legal Proceedings and Note 21 to the Consolidated Financial Statements.

From time to time the Company may be identified as a potentially responsible party to a Superfund site. The EPA (or a state) can either (a) allow such a party to conduct and pay for a remedial investigation, feasibility study and remedial action or (b) conduct the remedial investigation and action and then seek reimbursement from the parties. Each party can be held jointly, severally and strictly liable for all costs. These parties can also bring contribution actions against each other and seek reimbursement from their insurance companies. As a result, the Company may be responsible for the costs of remedial investigation and actions under the Superfund Act or other laws or regulations regarding the remediation of waste. The Company does not believe that any currently identified sites will result in significant liabilities.

The EPA amended its oil pollution prevention regulations in July 2002. The total projected cost of compliance with the new regulations is estimated to range from $10 to $15 million, representing primarily capital expenditures.

The EPA is also considering issuing new regulations that govern existing utilities that employ a cooling water intake structure, and whose flow levels exceed a minimum threshold. As currently written, EPA's proposed rule presents several control options under consideration for the final rule. The Company is evaluating facility information from Bremo, Chesapeake, Chesterfield, Mt. Storm, North Anna, Possum Point, Surry, and Yorktown Power Stations. Given the uncertainties of future action by EPA on this issue, the Company cannot predict the future impact on its operations at this time.

The Company has applied for or obtained the necessary environmental permits material to the operation of its electric generating stations. Many of these permits are subject to re-issuance and continuing review.

Nuclear Regulatory Commission

All aspects of the operation and maintenance of the Company's nuclear power stations are regulated by the NRC. Operating licenses issued by the NRC are subject to revocation, suspension or modification, and operation of a nuclear unit may be suspended if the NRC determines that the public interest, health or safety so requires.

The Company filed applications for a 20 year life-extension for the North Anna and Surry units in May 2001. The NRC has completed its review of the applications and the Company expects to receive a renewed license for these units in 2003. For more information on this matter, see Note 8 to the Consolidated Financial Statements.

From time to time, the NRC adopts new requirements for the operation and maintenance of nuclear facilities. In many cases, these new regulations require changes in the design, operation and maintenance of existing nuclear facilities. If the NRC adopts such requirements in the future, it could result in substantial increases in the cost of operating and maintaining the Company's nuclear generating units.

The NRC also requires the Company to decontaminate nuclear facilities once operations cease. This process is referred to as decommissioning, and the Company is required by the NRC to prepare for it financially. For information on compliance with the NRC financial assurance requirements, see Note 8 to the Consolidated Financial Statements.

Disposal of spent nuclear fuel is a significant issue associated with the operation and decommissioning of nuclear facilities. The Nuclear Waste Policy Act (NWPA) of 1982 requires a permanent, federal repository for high-level radioactive waste and spent nuclear fuel to be made available by January 31, 1998. In February 2002, the Secretary of Energy recommended that Yucca Mountain located in the state of Nevada be developed as the permanent repository. Final congressional approval was received in July 2002. The DOE is currently in the process of seeking approval of a NRC license to begin construction of the repository.

The Company and other utilities have petitioned the U.S. Court of Appeals for the 11th Circuit to review a matter involving the DOE and PECO Energy Company (PECO). The petitioners challenged the DOE's action that allowed PECO to take credits against payments PECO would have been making into the Nuclear Waste Fund (NWF). The credits are part of the DOE's settlement of PECO's claim regarding the DOE's failure to provide a permanent repository for spent nuclear fuel as required by the NWPA. The petition stated that the credits violated the NWPA by depleting the NWF and releasing PECO from a portion of its NWF obligation. The petition also sought injunction of the DOE's settlement agreement with PECO and as well as an injunction against DOE entering into similar agreements. In September 2002, the court issued its decision on the matter declaring the fee adjustment aspect of the settlement between PECO and DOE "null and void." The decision does not prevent DOE from settling claims related to DOE's breach of its contractual obligation to begin disposing of spent nuclear fuel, but precludes DOE from using the NWF to compensate utilities for damages incurred by utilities owing to DOE's breach of its NWF obligation to dispose of spent nuclear fuel.

Interconnections

The Company maintains major interconnections with Progress Energy, American Electric Power Company, Inc., Allegheny Energy, Inc., PJM–West and PJM. Through this major transmission network, the Company has arrangements with these entities for coordinated planning, operation, emergency assistance and exchanges of capacity and energy. See also *Regional Transmission Organization* in *Future Issues and Outlook* in MD&A.

Capital Requirements and Financing Program

See *Liquidity and Capital Resources* in MD&A for details about the Company's capital requirements and financing program including material estimated capital expenditures for environmental control facilities.

Sources of Energy

Virginia Electric and Power Company's Power Generation

Plant	Location	Primary Fuel Type	Net Owned Summer Capability (Mw)
Owned Utility Generation			
North Anna	Mineral, VA	Nuclear	1,628[a]
Surry	Surry, VA	Nuclear	1,625
Mt. Storm	Mt. Storm, WV	Coal	1,569
Chesterfield	Chester, VA	Coal	1,234
Chesapeake	Chesapeake, VA	Coal	595
Clover	Clover, VA	Coal	441[b]
Yorktown	Yorktown, VA	Coal	326
Possum Point	Dumfries, VA	Coal	322
Bremo	Bremo Bluff, VA	Coal	227
North Branch	Bayard, WV	Coal	74
Altavista	Altavista, VA	Coal	63
Southampton	Southampton, VA	Coal	63
Yorktown	Yorktown, VA	Oil	818
Possum Point	Dumfries, VA	Oil	786
Gravel Neck (CT)	Surry, VA	Oil	183
Darbytown (CT)	Richmond, VA	Oil	144
Chesapeake (CT)	Chesapeake, VA	Oil	144
Possum Point (CT)	Dumfries, VA	Oil	78
Northern Neck (CT)	Lively, VA	Oil	64
Low Moor (CT)	Covington, VA	Oil	60
Kitty Hawk (CT)	Kitty Hawk, NC	Oil	44
Remington (CT)	Remington, VA	Gas	580
Chesterfield (CC)	Chester, VA	Gas	397
Ladysmith (CT)	Ladysmith, VA	Gas	290
Bellmeade (CC)	Richmond, VA	Gas	230
Gravel Neck (CT)	Surry, VA	Gas	146
Darbytown (CT)	Richmond, VA	Gas	144
Bath County	Warm Springs, VA	Hydro	1,440[c]
Gaston	Roanoke Rapids, NC	Hydro	225
Roanoke Rapids	Roanoke Rapids, NC	Hydro	99
Other	Various	Various	15
			14,054
Purchased Capacity			3,758
Net Purchases			145
		Total Capacity	**17,957**

Note: (CT) denotes combustion turbine and (CC) denotes combined cycle

(a) Excludes 11.6 percent undivided interest owned by Old Dominion Electric Cooperative (ODEC).

(b) Excludes 50 percent undivided interest owned by ODEC.

(c) Excludes 40 percent undivided interest owned by Allegheny Generating Company, a subsidiary of Allegheny Energy, Inc.

Power Purchase Contracts

The Company purchases electricity under contracts with other suppliers to meet a portion of its system capacity requirements. As of December 31, 2002, the Company has 42 power purchase contracts with a combined dependable summer capacity of 3,758 Mw. For information on the financial obligations under these agreements, see Note 21 to the Consolidated Financial Statements.

Fuel for Electric Generation

The Company uses a variety of fuels to power its electric generation. These include a mix of both nuclear fuel and fossil fuel as described further below.

Nuclear Fuel Supply

The Company utilizes both long-term contracts and short-term purchases to support its nuclear fuel requirements. Worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices. Current agreements, inventories and spot market availability are expected to support current and planned fuel supply needs. Additional fuel is purchased as required to ensure optimum cost and inventory levels.

Fossil Fuel Supply

The Company utilizes coal, oil and natural gas in its fossil fuel operations. The Company's coal supply is obtained through long-term contracts and spot purchases. Oil and oil-fired generation are used primarily to support heavier system generation loads during very cold or very hot weather periods. System requirements are purchased mainly under short-term spot agreements.

Firm natural gas transportation contracts (capacity) exist that allow delivery of gas to our facilities. The Company's capacity portfolio allows flexible natural gas deliveries to its gas turbine fleet, while minimizing costs.

Item 2. Properties

The Company owns its principal properties in fee (except as indicated below), subject to defects and encumbrances that do not interfere materially with their use. Substantially all of the Company's property is subject to the lien of the mortgage securing its First and Refunding Mortgage Bonds.

The Delivery segment has approximately 6,000 miles of electric transmission lines. Portions of transmission lines cross national parks and forests under permits entitling the federal government to use, at specified charges, surplus capacity in the line if any exists.

The Delivery segment has obtained right-of-way grants from the apparent owners of real estate for most of the Company's electric lines, but underlying titles have not been examined except for transmission lines of 69 Kv or more. Where rights-of-way have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many electric lines are on publicly owned property, where permission to operate can be revoked.

The Company leases its headquarters facility from Dominion. In addition, the Energy and Delivery segments share certain leased buildings and equipment.

See *Virginia Electric and Power Company's Power Generation* under Item 1. Business for a list of the principal facilities utilized by the Energy segment.

Item 3. Legal Proceedings

From time to time, the Company is alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans or permits issued by various local, state and federal agencies for the construction or operation of facilities. From time to time, there may be administrative proceedings on these matters pending. In addition, in the ordinary course of business, the Company is involved in various legal proceedings. Management believes that the ultimate resolution of these proceedings will not have a material adverse effect on the Company's financial position, liquidity or results of operations.

See *Regulation* under Item 1. Business, *Rate Matters* in *Future Issues and Outlook* in MD&A and Note 21 to the Consolidated Financial Statements for additional information on rate matters and various regulatory proceedings to which the Company is a party.

During 2000, the Company received a Notice of Violation from the EPA, alleging that the Company failed to obtain New Source Review permits under the Clean Air Act prior to undertaking specified construction projects at the Mt. Storm Power Station in West Virginia. The Attorney General of New York filed a suit against the Company alleging similar violations of the Clean Air Act at the Mt. Storm Power

Station. The Company also received notices from the Attorneys General of Connecticut and New Jersey of their intentions to file suit for similar violations. In December 2002, the Attorney General of Connecticut filed a motion to intervene as a plaintiff in the action filed by the New York State Attorney General. This action has been stayed. Management believes that the Company has obtained the necessary permits for its generating facilities. The Company has reached an agreement in principle with the federal government and the state of New York to resolve this situation. The agreement in principle includes payment of a $5 million civil penalty, a commitment of $14 million for environmental projects in Virginia, West Virginia, Connecticut, New Jersey and New York, and a 12-year, $1.2 billion capital investment program for environmental improvements at the Company's coal-fired generating stations in Virginia and West Virginia. The Company had already committed to a substantial portion of the $1.2 billion expenditures for sulfur dioxide and nitrogen oxide emissions controls. The negotiations over the terms of a binding settlement have expanded beyond the basic agreement in principle and are ongoing. As of December 31, 2002, the Company has recorded, on a discounted basis, $18 million for the civil penalty and environmental projects

In June 2002, Wiley Fisher, Jr. and John Fisher filed a purported class action lawsuit against the Company and Dominion Telecom, Inc. (Dominion Telecom) in the U.S. District Court in Richmond, Virginia. The plaintiffs claim that the Company and Dominion Telecom strung fiber-optic cable across their land, along the Company's electric transmission corridor without paying compensation. The plaintiffs are seeking damages for trespass and "unjust enrichment" as well as punitive damages from the defendants. The named plaintiffs purport to "represent a class . . . consisting of all owners of land in North Carolina and Virginia, other than public streets or highways, that underlies the Company's electric transmission lines and on or in which fiber optic cable has been installed." The named plaintiffs have asked that the court allow the lawsuit to proceed as a class action. Discovery has begun and the court has granted a motion to add additional plaintiffs, Harmon T. Tomlinson, Jr. and Linda D. Tomlinson. The outcome of the proceeding, including an estimate as to any potential loss, cannot be predicted at this time.

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

None.

Part II

Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters

Dominion Resources, Inc. (Dominion) owns all of the Company's common stock.

The Company paid quarterly cash dividends on its common stock as follows:

	1st	2nd	3rd	4th
		(millions)		
2002	$135	$124	$208	$—
2001	81	73	178	60

Item 6. Selected Financial Data

	2002	2001[1]	2000	1999	1998[2]
			(millions)		
Operating revenue	$ 4,972	$ 4,944	$ 4,791	$ 4,591	$ 4,280
Income from operations	1,460	999	1,086	1,007	681
Income before extraordinary item and cumulative effect of a change in accounting principle	773	446	558	485	230
Extraordinary item (net of income taxes of $197)[3]				255	
Cumulative effect of a change in accounting principle (net of income taxes of $11)[4]			21		
Net income	773	446	579	230	230
Balance available for common stock	757	423	543	193	194
Total assets	15,163	13,784	13,331	11,765	11,985
Long-term debt, noncurrent capital lease obligations, preferred stock subject to mandatory redemption and preferred securities of subsidiary trust	4,216	3,864	3,722	3,716	3,805

(1) In 2001, the Company terminated seven long-term power purchase agreements and recorded an after-tax charge of $136 million See Power Purchase Contracts in Note 21 to the Consolidated Financial Statements

(2) Revenue for 1998 reflects the Company's settlement of base rate proceedings which included a one-time rate refund of $150 million and a base rate reduction of $100 million beginning in March 1998. Net income for 1998 reflects the aforementioned base rate refund and rate reduction, as well as an impairment charge of $159 million to write-off net regulatory assets no longer considered recoverable as a result of the rate settlement.

(3) In 1999, the Company discontinued the application of Statement of Financial Accounting Standards (SFAS) No 71, *Accounting for the Effects of Certain Types of Regulation,* to its generation operations in connection with the deregulation of these operations in Virginia. The discontinuance of SFAS No. 71 for generation resulted in a $255 million after-tax charge in 1999, representing the net effect of writing off generation-related assets and liabilities not expected to be recovered through rates or wires charges during the transition period established by the Virginia Electric Utility Restructuring Act

(4) Effective January 1, 2000, the Company recognized the effect of a change in the method of calculating the market-related value of pension plan assets See Note 3 to the Consolidated Financial Statements

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

Introduction

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) discusses the results of operations and general financial condition of Virginia Power. MD&A should be read in conjunction with the Consolidated Financial Statements. "The Company" is used throughout MD&A and, depending on the context of its use, may represent any of the following: the legal entity, Virginia Electric and Power Company, one of Virginia Power's consolidated subsidiaries or the entirety of Virginia Power and its consolidated subsidiaries. The Company is a wholly-owned subsidiary of Dominion Resources, Inc. (Dominion).

Risk Factors and Cautionary Statements That May Affect Future Results

This report contains statements concerning the Company's expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. In most cases, the reader can identify these forward-looking statements by words such as "anticipate," "estimate," "forecast," "expect," "believe," "should," "could," "plan," "may" or other similar words.

The Company makes forward-looking statements with full knowledge that risks and uncertainties exist that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ are often presented with the forward-looking statements themselves. In addition, other factors could cause actual results to differ materially from those indicated in any forward-looking statement. These factors include weather conditions; fluctuations in energy-related commodities prices and the effect these could have on the Company's earnings, liquidity position, and the underlying value of its assets; trading counterparty credit risk; capital market conditions, including price risk due to marketable securities held as investments in trusts and benefit plans; changes in rating agency requirements or ratings; changes in accounting standards; the risks of operating businesses in regulated industries that are becoming deregulated; transfer of control over the Company's transmission facilities to a regional transmission entity; collective bargaining agreements and labor negotiations; and political and economic conditions (including inflation rates). Some more specific risks are discussed below.

The Company bases its forward-looking statements on management's beliefs and assumptions using information available at the time the statements are made. The Company cautions the reader not to place undue reliance on its forward-looking statements because the assumptions, beliefs, expectations and projections about future events may and often do materially differ from actual results. The Company undertakes no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

The Company's operations are weather sensitive—The Company's results of operations can be affected by changes in the weather. Weather conditions directly influence the demand for electricity and affect the price of energy commodities. In addition, severe weather, including hurricanes, winter storms and droughts, can be destructive, causing outages, property damage and requiring the Company to incur additional expenses.

The Company is subject to complex government regulation which could adversely affect its operations—The Company's operations are subject to extensive regulation and require numerous permits, approvals and certificates from various federal, state and local governmental agencies. The Company must also comply with environmental legislation and other regulations. Management believes the necessary approvals have been obtained for the Company's existing operations and that its business is conducted in accordance with applicable laws. However, new laws or regulations or the revision or reinterpretation of existing laws or regulations may require the Company to incur additional expenses.

Costs of environmental compliance, liabilities and litigation could exceed the Company's estimates—Compliance with federal, state and local environmental laws and regulations may result in increased capital, operating and other costs, including remediation and containment and monitoring obligations. In addition, the Company may be a responsible party for environmental clean up at a site identified by a regulatory body. Management cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean up costs and compliance, and the possibility that changes will be made to the current environmental laws and regulations. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties.

Capped electric rates in Virginia may be insufficient to allow full recovery of stranded and other costs—Under the Virginia Utility Restructuring Act, the Company's base rates (excluding fuel costs and certain other allowable adjustments) remain unchanged until July 2007 unless modified or terminated consistent with that Act. The capped rates and wires charges that, where applicable, are being assessed to customers opting for alternative suppliers allow the Company to recover certain generation-related costs and fuel costs; however, the Company remains exposed to numerous risks of cost-recovery shortfalls. These include exposure to potentially stranded costs, future environmental compliance requirements, changes in tax laws, inflation and increased capital costs. See Future Issues and Outlook in MD&A and Note 21 to the Consolidated Financial Statements.

The electric generation business is subject to competition—Effective January 1, 2002, the generation portion of the Company's operations in Virginia is open to competition and is no longer subject to cost-based rate regulation. As a result there is increased pressure to lower costs, including the cost of purchased electricity. Because the Company's generation business has not previously operated in a competitive environment, the extent and timing of entry by additional competitors into the electric market in Virginia is unknown. Therefore, it is difficult to predict the extent to which the Company will be able to operate profitably within this new environment.

There are inherent risks in the operation of nuclear facilities—The Company operates nuclear facilities that are subject to inherent risks. These include the threat of terrorist attack and ability to dispose of spent nuclear fuel, the disposal of which is subject to complex federal and state regulatory constraints. These risks also include the cost of and the Company's ability to maintain adequate reserves for decommissioning, costs of plant maintenance and exposure to potential liabilities arising out of the operation of these facilities. The Company maintains decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks. However, it is possible that costs arising from claims could exceed the amount of any insurance coverage.

The use of derivative instruments could result in financial losses—The Company uses derivative instruments including futures, forwards, options and swaps, to manage its commodity and financial market risks. In addition, the Company purchases and sells commodity-based contracts in the natural gas, electricity and oil markets for trading purposes. In the future, the Company could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts. For additional information concerning the Company's derivatives and commodity-based trading contracts, see Market Rate Sensitive Instruments and Risk Management in MD&A and Notes 2 and 9 the Consolidated Financial Statements.

The Company is exposed to market risks beyond its control in its energy clearinghouse operations—The Company's energy clearinghouse and risk management operations are subject to multiple market risks including market liquidity, counterparty credit strength and price volatility. Many industry participants have experienced severe business downturns during the past year resulting in some being forced to exit or curtail their participation in the energy trading markets. This has led to a reduction in the number of trading partners, lower industry trading revenues and lower than expected revenues in the Company's energy clearinghouse operations. Declining credit worthiness of some of the Company's trading counterparties may limit the level of its trading activities with these parties and increase the risk that these counterparties may not perform under a contract.

An inability to access financial markets could affect the execution of the Company's business plan—The Company relies on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flows of its operations. Management believes that the Company and its subsidiaries will maintain sufficient access to these financial markets based upon current credit ratings. However, certain disruptions outside of the Company's control may increase its cost of borrowing or restrict its ability to access one or more financial markets. Such disruptions could include an economic downturn, the bankruptcy of an unrelated energy company or changes to the Company's credit ratings. Restrictions on the Company's ability to access financial markets may affect its ability to execute its business plan as scheduled.

Changing rating agency requirements could negatively affect the Company's growth and business strategy—As of March 1, 2003, the Company's senior secured debt is rated A-, stable outlook, by Standard and Poors Rating Group, a division of the McGraw-Hill Companies, Inc. (Standard & Poor's) and A2, stable outlook, by Moody's Investor Service (Moody's). Both agencies have recently implemented more stringent applications of the financial requirements for various ratings levels. In order to maintain its current credit ratings in light of these or future new requirements, the Company may find it necessary to take steps or change its business plans in ways that may adversely affect its growth and earnings. A reduction in the Company's credit ratings by either Standard & Poor's or Moody's could increase its borrowing costs and adversely impact its results of operations.

Potential changes in accounting practices may adversely affect the Company's financial results—The Company cannot predict the impact of any future changes in accounting regulations or practices in general with respect to public companies, the energy industry or in its operations specifically. New accounting standards could be issued by the Financial Accounting Standards Board (FASB) or the Securities and Exchange Commission (SEC) which could impact the way the Company is required to record revenues, expenses, assets and liabilities. These changes in accounting standards could adversely affect the Company's reported earnings or increase its liabilities.

Operating Segments

In general, management's discussion of the Company's results of operations focuses on the contributions of its operating segments. However, the discussion of the Company's financial condition under *Liquidity and Capital Resources* is for the entire company. The Company's two primary operating segments are:

> **Energy** manages the Company's portfolio of generating facilities and power purchase contracts and its energy trading and marketing, hedging and arbitrage activities. Energy's operating results reflect: the impact of weather on demand for electricity; customer growth as influenced by overall economic conditions; and changes in prices of commodities, primarily electricity and natural gas, that the segment actively markets and trades, uses for hedging purposes and consumes in generation activities. The cost of fuel used in generation operations and electric energy purchases incurred by the Company to serve Virginia and North Carolina retail customers is generally recoverable through rates charged to customers.
>
> **Delivery** manages the Company's electric distribution and transmission systems as well as customer service. Delivery's operating results reflect the impact of weather on demand for electricity and customer growth as influenced by overall economic conditions. The segment is subject to cost-of-service rate regulation and base rates are currently capped in Virginia and North Carolina.

In addition, the Company also reports Corporate and Other as a segment. The Company includes certain expenses which are not allocated to the Energy and Delivery segments in Corporate and Other.

Effective January 1, 2003, the Company's electric transmission operations became a part of the Energy segment instead of the Delivery segment. For more information on the Company's operating segments, see Note 26 to the Consolidated Financial Statements.

Critical Accounting Policies

The Company has identified the following accounting policies that, as a result of the judgments, uncertainties, uniqueness and complexities of the underlying accounting standards and operations involved, could result in material changes to its financial condition or results of operations under different conditions or using different assumptions.

Accounting for risk management and energy trading contracts at fair value—The Company uses derivatives to manage its commodity, financial market and currency exchange risks. In addition, the Company purchases and sells commodity-based contracts in the natural gas, electricity and oil markets for trading purposes. The accounting requirements for derivatives and hedging activities are complex and interpretation of these requirements by standard-setting bodies is ongoing. All derivatives, other than specific exceptions, are reported on the Consolidated Balance Sheets at fair value, beginning in 2001. Energy trading contracts are also reported on the Consolidated Balance Sheets at fair value. Changes in fair value, except those related to derivative instruments designated as cash flow hedges, are generally included in the determination of the Company's net income at each financial reporting date until the contracts are ultimately settled. The measurement of fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, measurement involves judgment and estimates. These estimates are based on valuation methodologies deemed appropriate by the Company's management. For individual contracts, the use of different assumptions could have a material effect on the contract's estimated fair value. In addition, for hedges of forecasted transactions, the Company must estimate the expected future cash flows of forecasted transactions, as well as evaluate the probability of occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could affect the timing of recognition of changes in fair value of certain hedging derivatives. See *Selected Information—Energy Trading Activities* and *Market Rate Sensitive Instruments* and *Risk Management* in MD&A and Notes 2, 9, and 21 to the Consolidated Financial Statements.

Accounting for regulated operations—Methods of allocating costs to accounting periods for operations subject to federal or state cost-of-service rate regulation may differ from accounting methods generally applied by nonregulated companies. When the timing of cost recovery prescribed by regulatory authorities differs from the timing of expense recognition used for accounting purposes, the Company's Consolidated Financial Statements may recognize a regulatory asset for expenditures that otherwise would be expensed. Regulatory assets represent probable future revenue associated with certain costs that will be recovered from customers through rates. Regulatory liabilities represent probable future reductions in revenue associated with expected customer credits through rates. Management makes assumptions regarding the probability of regulatory asset recovery through future rates approved by applicable regulatory authorities. The expectations of future recovery are generally based upon historical experience, as well as discussions with applicable regulatory authorities. If recovery of regulatory assets is determined to be less than probable, they would be expensed in the period such assessment is made. See Notes 2 and 10 to the Consolidated Financial Statements.

Long-lived assets—In testing the Company's long-lived assets and intangible assets with definite lives for potential impairment in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, the Company is required to estimate the future cash flows associated with individual assets or groups of assets. Although the cash flow estimates used by the Company are based on the best information available at the time the estimates are made, estimates of future cash flows are by nature highly uncertain and may vary significantly from actual results.

If the sum of the undiscounted estimated future cash flows exceeds the related asset's carrying amount, no impairment exists. Otherwise, there is potential impairment that must be measured by comparing the fair value of the asset to its carrying amount. An asset's fair value is determined by calculating the present value of its expected future cash flows, which requires management to select an appropriate discount rate. The recognition of an asset impairment would result in a charge to earnings, with a corresponding reduction of the carrying amount of the related property, plant and equipment or intangible asset.

Results of Operations

The Company's discussion of its results of operations includes an overview of its operating revenue and operating results for 2002 and 2001 on a consolidated basis. These sections are followed by a more detailed discussion of the results of operations of the operating segments. For additional information about the Company's operating segments, see Note 26 to the Consolidated Financial Statements.

	Year Ended December 31,								
	Net Income			Operating Revenue			Operating Expenses		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
	(millions)								
Energy	$447	$ 380	$369	$3,697	$3,722	$3,577	$2,865	$2,953	$2,900
Delivery	322	230	246	1,263	1,212	1,210	638	713	718
Corporate and Other	4	(164)	(36)	12	10	4	9	279	87
Total	$773	$ 446	$579	$4,972	$4,944	$4,791	$3,512	$3,945	$3,705

Overview of Operating Revenue—Consolidated

The following is a general discussion of factors that affect operating revenue for both the Energy and Delivery segments.

The majority of the Company's operating revenue is provided through bundled rate tariffs. Regulated electric sales consist primarily of sales to retail customers at rates authorized by the Virginia Commission and the North Carolina Utilities Commission (North Carolina Commission), and sales to cooperatives and municipalities at wholesale rates authorized by the Federal Energy Regulatory Commission (FERC). Also included in regulated electric sales are amounts received from others for use of the Company's transmission system to transport electric energy under tariffs authorized by FERC.

In addition, regulated electric sales include revenue from fuel rates which are subject to approval by regulatory authorities and are designed to recover the cost of fuel used in generating electricity from customers served under regulated tariffs.

Overview of 2002 Results—Consolidated

Net income increased $327 million to $773 million, as compared to 2001. Net income increased in 2002 due primarily to an after-tax charge of $136 million taken in the first quarter of 2001 in connection with the termination of certain long-term power purchase agreements under which the Company previously purchased electric energy. Comparably warmer temperatures in the summer of 2002 and customer growth in the Company's regulated electric service territories resulted in higher regulated electric revenues for 2002. The increase in regulated electric revenue for 2002 included the effect of a $34 million decrease in revenues from wholesale customers served under requirements contracts. For further information, see *Capacity* below in MD&A. The contribution from the Company's electric and gas trading and power marketing activities decreased for 2002. Total operating expenses decreased, compared to 2001, primarily due to lower depreciation and other operations and maintenance expense.

Operating revenue increased $28 million to $4.9 billion for 2002, as compared to 2001. Regulated electric sales increased $237 million, and other revenue decreased $209 million. Favorable weather conditions, reflecting increased cooling and heating degree-days, as well as customer growth, are estimated to have contributed approximately $195 million and $60 million, respectively, to the $237 million increase in regulated electric sales. Fuel rate recoveries increased approximately $65 million for 2002. These recoveries are generally offset by related increases in electric fuel expense and do not materially affect income. Partially offsetting these increases was a net decrease of $83 million due to other factors not separately measurable. These factors include the impact of economic conditions on customer usage, especially non-residential customers, as well as variations in seasonal rate premiums and discounts. There were 31 percent more cooling degree-days in 2002 and 2 percent more heating degree-days, as compared to 2001. The Company served, on average, 43,000 more retail customers during 2002.

Other revenue from energy trading activities decreased $218 million. For further information, see the *Energy Segment* below. Miscellaneous revenue increased by $9 million over the comparable period in 2001.

Operating expenses decreased $433 million to $3.5 billion for 2002, as compared to 2001. Electric fuel and energy purchases, net and purchased electric capacity increased in 2002. The Company incurred restructuring costs in both 2001 and 2000, primarily associated with Dominion's acquisition of Consolidated Natural Gas (CNG) and subsequent integration of the combined companies' operations. Other operations and maintenance expenses were lower in 2002, primarily due to additional costs incurred in 2001 associated with the termination of certain long-term power purchase contracts. For further information on these restructuring costs and termination of the power purchase contracts, see the *Corporate and Other Segment* discussed below. Depreciation and amortization decreased, primarily due to changes in the estimated useful lives of the Company's fossil-fueled generating plants and transmission and distribution properties, offset by the effect of routine property additions. These changes in the estimated useful lives reduced depreciation expense by approximately $40 million for 2002. See Note 2 to the Consolidated Financial Statements. Other taxes decreased, as compared to 2001, primarily due to a reduction in average business and occupation tax rates and the impact of a favorable resolution of prior year sales and use tax issues.

Interest and related charges decreased, primarily as a result of lower interest rates on outstanding debt. Expenses associated with the preferred securities of subsidiary trusts increased, primarily due to the higher amount of outstanding trust preferred securities at December 31, 2002. In addition, the Company's effective income tax rate decreased. See Note 7 to the Consolidated Financial Statements.

Overview of 2001 Results—Consolidated

Operating revenue increased $153 million to $4.9 billion for 2001, as compared to 2000. The increase was due primarily to higher fuel rate recoveries, growth in the number of retail customers and increased wholesale sales to cooperatives and municipalities under requirements contracts. These factors were offset by milder weather conditions in 2001. While there were 6 percent more cooling degree-days in the summer of 2001, as compared to 2000, the 10 percent decline in 2001 heating degree-days more than offset the benefit from the higher summer sales. The Company served, on average, 40,000 more retail customers during 2001. The results of the Company's electric and gas trading and marketing operations also contributed approximately $24 million to the increase in operating revenue.

Operating expenses increased $240 million to $3.9 billion for 2001, as compared to 2000. Higher prices for commodities consumed contributed to increased electric fuel and energy purchases, net. Purchased electric capacity expense decreased as the Company terminated certain contracts in early 2001. See Note 21 to the Consolidated Financial Statements. Depreciation and amortization decreased primarily due to a change in the estimated useful lives of the Company's nuclear plants in connection with the expected re-licensing of those plants, offset by routine property additions. The change in useful lives of the nuclear facilities reduced depreciation expense by approximately $72 million for 2001. For further information, see the *Energy Segment* and Note 2 to the Consolidated Financial Statements. The Company incurred restructuring costs in both 2001 and 2000 primarily associated with Dominion's acquisition of CNG and subsequent integration of the combined companies' operations. Other operations and maintenance expenses increased primarily due to costs associated with the termination of certain long-term power purchase contracts. For further information on these restructuring costs and termination of the power purchase contracts, see the *Corporate and Other Segment* discussed below. The Company's effective income tax rate increased and other taxes decreased in 2001 due to its utility operations in Virginia becoming subject to state income taxes in lieu of gross receipts taxes.

Segment Results

Energy Segment

	2002	2001	2000
		(millions)	
Operating revenue	$3,697	$3,722	$3,577
Operating expense	2,865	2,953	2,900
Net income contribution	447	380	369
Energy supplied (million mwhrs)	76	75	76

The Company provides electricity primarily from the following fuel sources: nuclear, coal, oil and purchased power. System energy output by energy source and the average fuel cost for each are shown below. Fuel cost is presented in mills (one tenth of one cent) per kilowatt-hour.

	2002		2001		2000	
	Source	Cost	Source	Cost	Source	Cost
Nuclear[1]	32%	$ 4.63	31%	$ 4.64	33%	$ 4.48
Coal[2]	43	16.72	40	16.55	42	14.04
Oil	4	36.58	5	36.41	3	35.89
Purchased power, net	19	27.36	21	24.38	20	23.97
Other	2	53.72	3	42.37	2	44.58
Total	100%		100%		100%	
Average fuel cost		16.46		16.35		14.20

(1) Excludes Old Dominion Electric Cooperative's (ODEC) 11.6 percent ownership interest in the North Anna Power Station.

(2) Excludes ODEC's 50 percent ownership interest in the Clover Power Station.

2002 Results

Energy's net income contribution increased $67 million to $447 million for 2002, as compared to 2001. The increase in net income primarily reflects a $88 million decrease in operating expenses, partially offset by a $25 million decrease in operating revenue.

Comparably warmer temperatures during the summer of 2002 and customer growth contributed approximately $133 million and $41 million, respectively, to the $179 million increase in the Energy's segment regulated electric sales, partially offset by other factors as discussed above in *Overview of 2002 Results—Consolidated.*

In addition, Energy manages the Company's energy trading, hedging, arbitrage and power marketing activities through the Dominion Energy Clearinghouse (the Clearinghouse). The Company's electric trading revenue, representing net gains and losses from contract settlements and unrealized changes in the fair value of contracts not yet settled, decreased by approximately $32 million, as compared to 2001. This decrease reflects the effect of unfavorable price changes and lower trading margins. Power marketing sales decreased by approximately $74 million, as compared to 2001. Less generation was available for sale in the wholesale markets primarily due to the higher demand of the Company's utility service territory customers during 2002. Gas trading revenue, net of cost of sales, decreased approximately $112 million. Approximately $70 million of this decrease relates to contracts held by one of the Company's unregulated subsidiaries as part of Dominion's consolidated price risk management strategy associated with anticipated sales of Dominion's 2002 and 2003 natural gas production. Other miscellaneous revenue increased by approximately $14 million over the comparable period in 2001 primarily due to increases in sales of other commodities.

Operating expenses decreased $88 million for 2002, as compared to 2001. Electric fuel and energy purchases, net increased $29 million as a result of a $66 million increase in electric fuel and energy purchases subject to rate recovery, partially offset by a $37 million decrease in fuel expenses attributable to less wholesale marketing of utility plant generation. Purchased electric capacity costs increased by $11 million due to additional capacity acquired to serve utility demand in 2002. Depreciation expense decreased by $13 million, reflecting the effect of changes in the estimated useful lives of fossil-fired generation property, partially offset by the impact of new property additions. See Note 2 to the Consolidated Financial Statements. Other operations and maintenance decreased $95 million in 2002, primarily reflecting a $68 million decrease in scheduled outages and routine maintenance costs at both nuclear and fossil plants and a $27 million decrease in general and administrative expenses. Other taxes decreased approximately $20 million, as compared to 2001, primarily due to a reduction in average business and occupation tax rates and the impact of a favorable resolution of prior year sales and use tax issues.

2001 Results

Customer growth and the increase in fuel rate recoveries contributed to the increase in Energy's regulated electric sales. See *Overview of Operating Revenue—Consolidated and Overview of 2001 Results—Consolidated.* The results of the Company's electric and gas trading and marketing operations also contributed approximately $24 million to the increase in operating revenue for the Energy segment.

Operating expenses increased $53 million for 2001, as compared to 2000. Electric fuel and energy purchases, net were higher in 2001, reflecting higher fuel prices for coal and oil consumed. The effect of such expenses on net income was mitigated by increased fuel rate revenue, including higher levels of recovery for previously deferred fuel costs. Purchased electric capacity costs decreased as a result of the termination of long-term power purchase agreements in the first quarter of 2001. The decrease in depreciation and amortization expense primarily reflects a $72 million decrease from a change in the estimated useful lives of the Company's nuclear plants. This change was based on the Company's expectation that 20-year extensions of the operating licenses for its nuclear facilities will be granted. The application was filed with the Nuclear Regulatory Commission (NRC) in May 2001. The Company expects to receive a renewed license for these units in 2003. This decrease was partially offset by additional depreciation expense related to other recent generation-related capital expenditures. Other operations and maintenance increased due to scheduled outages at both nuclear and fossil plants. Other taxes decreased reflecting a change in Virginia whereby the Company became subject to state income taxes in lieu of gross receipts taxes effective January 2001.

Selected Information—Energy Trading Activities

As discussed earlier, Energy manages the Company's energy trading, hedging and arbitrage activities through the Clearinghouse. The Company believes these operations complement its integrated energy business and facilitate its risk management activities. As part of these operations, the Clearinghouse enters into contracts for purchases and sales of energy-related commodities, including natural gas, electricity and oil. Settlement of a contract may require physical delivery of the underlying commodity or, in some cases, an exchange of cash. These contracts are classified as energy trading contracts for financial accounting purposes, and are included in the Consolidated Balance Sheets as components of current and non-current derivative and energy trading assets and liabilities. Gains and losses from energy trading contracts, including both realized and unrealized amounts, are reported net in the Consolidated Statements of Income as revenue.

In accordance with generally accepted accounting principles, the Company reports energy trading contracts in its financial statements at fair value. For a discussion of how the Company determines fair value for its energy trading contracts, see *Critical Accounting Policies* presented earlier in MD&A. The Clearinghouse enters into contracts with the objective of benefiting from changes in the prices of energy commodities. Clearinghouse management continually monitors its contract positions, considering location and timing of delivery or settlement for each energy commodity in relation to market price activity, seeking arbitrage opportunities For example, after entering into a contract to purchase a commodity, the Clearinghouse typically enters into a sales contract, or a combination of sales contracts, with quantities and delivery or settlement terms that are identical or very similar to those of the purchase contract. When the purchase and sales contracts are settled either by physical delivery of the underlying commodity or by net cash settlement, the Clearinghouse may receive a net cash margin (a realized gain), or sometimes will pay a net cash margin(a realized loss).

Until the contracts are settled, however, the Company must record the changes in the fair value of both contracts. These changes in fair value represent unrealized gains and losses. To the extent purchase and sales contracts with identical or similar terms are held by the Clearinghouse, the changes in their fair values will generally offset one another. Although the Clearinghouse may hold purchase or sales contracts for delivery of commodities at particular locations and times that have not been offset, such exposures are monitored and actively managed on a daily basis. The Company's risk management policies and procedures are designed to limit its exposure to commodity price changes.

For additional discussion, see *Market Rate Sensitive Instruments and Risk Management* and Notes 2, 9, and 23 to the Consolidated Financial Statements. Also, see Note 4 to the Consolidated Financial Statements, for a discussion of the Company's implementation of new accounting requirements effective January 1, 2003 to reflect the decisions of the Emerging Issues Task Force (EITF) in Issue No. 02-3, *Issues Involved in Accounting for Contracts under Issue No. 98-10.* As a result, some energy-related contracts are no longer subject to fair value accounting.

A summary of the changes in the unrealized gains and losses in the Company's energy trading contracts during 2002 follows:

	Energy Trading Contracts
	(millions)
Net unrealized gain at December 31, 2001	$154
Contracts realized or otherwise settled during the period	(65)
Net unrealized gain at inception of contracts initiated during the period	31
Changes in valuation techniques	—
Other changes in fair value	(9)
Net unrealized gain at December 31, 2002	$111

The balance of net unrealized gains and losses in the Company's energy trading contracts at December 31, 2002 is summarized in the following table based on the approach used to determine fair value and the contract settlement or delivery dates:

	Maturity Based on Contract Settlement or Delivery Date(s)					
Source of Fair Value	Less Than 1 Year	1-2 Years	2-3 Years	3-5 Years	In Excess of 5 Years	Total
			(millions)			
Actively quoted[1]	$ (7)	$16	$12	—	—	$ 21
Other external sources[2]	—	14	6	$ 5	—	25
Models and other valuation techniques[3]	19	7	6	10	$ 23	65
Total	$ 12	$37	$24	$ 15	$ 23	$111

(1) Exchange-traded and over-the-counter contracts.

(2) Values based on prices from over-the-counter broker activity and industry services and, where applicable, conventional option pricing models.

(3) Values based on the Company's estimate of future commodity prices when information from external sources is not available and use of internally-developed models, reflecting option pricing theory, discounted cash flow concepts, etc.

Delivery Segment

	2002	2001	2000
		(millions)	
Operating revenue	$1,263	$1,212	$1,210
Operating expense	638	713	718
Net income contribution	322	230	246
Electricity delivered to utility customers (million mwhrs)	75	72	74

2002 Results

Delivery's net income contribution increased $92 million to $322 million for 2002, as compared to 2001. The increase in net income reflects a $51 million increase in operating revenue and a $75 million decrease in operating expenses. These amounts were partially offset by increases in income tax expense.

Comparably warmer temperatures during the summer of 2002 and customer growth contributed approximately $62 million and $19 million, respectively, to the $58 million increase in the Delivery segment's regulated electric sales, partially offset by other factors as discussed above in *Overview of 2002 Results—Consolidated.* Miscellaneous revenue decreased $7 million from 2001.

Operating expenses were $638 million in 2002, as compared to $713 million in 2001. Operations and maintenance expense decreased approximately $57 million, reflecting a decrease in general and administrative salaries, materials and supplies and expenditures for contractors. Also, Delivery's operating expenses can be impacted by severe weather. Hurricanes, major thunderstorms and ice storms can damage the Company's distribution and transmission systems. There was an approximate $6 million increase in service restoration costs recorded in other operations and maintenance expense due to ice storms in late 2002. Depreciation expense decreased by $10 million, reflecting the effect of changes in the estimated useful lives of distribution property, partially offset by the impact of new property additions. See Note 2 to the Consolidated Financial Statements. Other taxes decreased $7 million, as compared to 2001, primarily due to a reduction in average business and occupation tax rates and the impact of a favorable resolution of prior year sales and use tax issues.

2001 Results

Customer growth was the main contributor to the increase in the Delivery's segment regulated electric sales. Also, see *Overview of Operating Revenue—Consolidated* and *Overview of 2001 Results—Consolidated*

Operating expenses were $713 million in 2001, as compared to $718 million in 2000. During 2001 and 2000, there were no unusual levels of storm restoration activities. Depreciation and amortization increased slightly as a result of routine property additions. Other operations and maintenance expenses included a moderate increase in provisions for uncollectible customer accounts. Other taxes decreased, reflecting a change in Virginia whereby the Company's utility operations became subject to state income taxes in lieu of gross receipts taxes effective January 2001.

Corporate and Other

	2002	2001	2000
		(millions)	
Net income contribution (expense) ..	4	(164)	(36)

2002 Results

Corporate and other operations reported income, net of related taxes, of $4 million in 2002, as compared to expenses, net of related taxes, of $164 million in 2001, primarily due to costs associated with the purchase of three non-utility generating plants and termination of certain long-term power purchase contracts in 2001. In addition, these results include a pre-tax adjustment of $7 million recorded in 2002 to adjust liabilities that resulted from restructuring activities initiated late in 2001. For further information, see Notes 6 and 21 to the Consolidated Financial Statements.

2001 Results

Corporate and other operations reported expenses, net of related taxes, of $164 million in 2001, an increase of $128 million, as compared to 2000. These results include pre-tax restructuring costs of $48 million and a pre-tax charge of $220 million related to costs associated with the purchase of three non-utility generating plants and termination of certain long-term power purchase contracts. See Notes 6 and 21 to the Consolidated Financial Statements.

Liquidity and Capital Resources

The Company depends on both internal and external sources of liquidity to provide working capital and to fund capital requirements. Short-term cash requirements not met by cash flow provided by operating activities are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through sales of securities and additional long-term debt financing.

Internal Sources of Liquidity

Cash flow from operating activities provided $1.3 billion in 2002 and $1.1 billion during each year in 2001 and 2000. The Company's management believes that its operations provide a stable source of cash flow sufficient to contribute to planned levels of capital expenditures and maintain current dividends payable to Dominion. As noted above, the Company uses a combination of short-term borrowings and sales of securities to fund capital requirements not covered by the timing or amounts of operating cash flows.

The Company's operations are subject to risks and uncertainties that may negatively impact cash flows from operations. Such risks and uncertainties include, but are not limited to, the following:

- unusual weather and its effect on energy sales to customers and energy commodity prices;
- extreme weather events that could disrupt or cause catastrophic damage to the Company's electric distribution and transmission systems;
- exposure to unanticipated changes in prices for energy commodities purchased or sold, including the effect on derivative instruments that may require the use of funds to post margin deposits with counterparties;
- effectiveness of Dominion's risk management activities and underlying assessment of market conditions and related factors, including energy commodity prices, basis, counterparty credit risk, liquidity, volatility, availability of generation and transmission capacity, currency exchange rates and interest rates;
- the cost of replacement electric energy in the event of longer-than- expected or unscheduled generation outages;
- contractual or regulatory restrictions on transfers of funds among the Company and Dominion and the Company and its subsidiaries; and
- timeliness of recovery for costs subject to cost-of-service utility rate regulation.

External Sources of Liquidity

The Company relies on access to bank and capital markets as a significant source of liquidity for capital requirements not satisfied by the cash provided by the Company's operations. As discussed further in the

Credit Ratings section below, the Company's ability to borrow funds or issue securities and the return demanded by investors are affected by the Company's credit ratings. In addition, the raising of external capital is subject to certain regulatory approvals, including the SEC and the Virginia Commission.

During 2002, the Company issued long-term debt (net of exchanged debt), trust preferred securities and preferred stock totaling approximately $1.1 billion. As discussed below, proceeds were used primarily to fund the repayment of short-term debt; the repayment of long-term debt maturities; and the Company's capital expenditures.

Credit Facilities and Short-Term Debt

In May 2002, Dominion, CNG and the Company entered into two joint credit facilities that allow aggregate borrowings of up to $2 billion. The facilities include a $1.25 billion 364-day revolving credit facility that terminates in May 2003 and a $750 million three-year revolving credit facility that terminates in May 2005. The Company expects to renew the 364-day revolving credit facility prior to its maturity in May 2003. These joint credit facilities are used for working capital, as support for the combined commercial paper programs of Dominion, CNG and the Company and other general corporate purposes. The three-year facility can also be used to support up to $200 million of letters of credit. At December 31, 2002, total outstanding letters of credit supported by the three-year facility were $106 million, which were issued by Dominion on behalf of its other subsidiaries.

At December 31, 2002, total outstanding commercial paper supported by the joint credit facilities was $1.2 billion, of which the Company's borrowings were $443 million, with a weighted average interest rate of 1.67 percent. At December 31, 2001, total outstanding commercial paper supported by previous credit agreements was $1.9 billion, of which the Company's borrowings were $436 million, with a weighted average interest rate of 1.96 percent. Commercial paper borrowings are used primarily to fund working capital requirements and may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash provided by operations.

Long-Term Debt

In 2002, the Company redeemed its $200 million, 6.75 percent 1997-A mortgage bonds due February 1, 2007 with part of the proceeds from the issuance of $650 million, 5.375 percent senior notes due February 1, 2007 (Senior Notes). The redemption included a direct exchange of Senior Notes for $117 million of the mortgage bonds. The Company used the remaining cash proceeds from the issuance of the Senior Notes to redeem the remaining $83 million of the mortgage bonds and for general corporate purposes, including the repayment of other debt.

In 2002, the Company repaid the following long-term debt securities:

- $280 million of medium-term notes, various series;
- $83 million of 1997-A, 6.75 percent mortgage bonds, as described above;
- $155 million of 1992-E, 7.375 percent mortgage bonds; and
- $100 million 1993-F, 6 percent mortgage bonds.

In February 2003, the Company issued $400 million aggregate principal amount of its 2003 Series A 4.75 percent senior notes due 2013. The Company plans to use the proceeds for general corporate purposes, including the repayment of other debt.

Company Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust and Preferred Stock

During 2002, the Company, through Virginia Power Capital Trust II, issued $400 million of 7.375 percent trust preferred securities. The trust preferred securities must be redeemed when the trust's sole assets, the junior subordinated notes due 2042 issued by the Company, are redeemed. The Company used the net proceeds from the sale of trust preferred securities primarily to redeem its June 1989 Series, September 1992A Series, September 1992B Series, and October 1988 Series variable rate preferred stock for $250 million and the 8.05 percent trust preferred securities of Virginia Power Capital Trust I for $135 million. See Note 16 to the Consolidated Financial Statements for additional discussion of the capital trust securities.

During 2002, the Company issued 1,250 units consisting of 1,000 shares per unit of cumulative preferred stock for $125 million. The preferred stock has a dividend rate of 5.50 percent until the end of the initial dividend period on December 20, 2007. The dividend rate for subsequent periods will be determined according to periodic auctions. The preferred stock has a liquidation preference of $100 per share plus accumulated and unpaid dividends. The Company used the proceeds for general corporate purposes and to repay debt. See Note 17 to the Consolidated Financial Statements.

Common Stock

In exchange for a $150 million reduction in amounts payable to Dominion, the Company issued common stock to Dominion.

Borrowings from Parent

During 2002, Dominion advanced $100 million, net of repayments, to certain unregulated subsidiaries of the Company pursuant to a short-term demand note. Interest charges incurred by the Company were not material. See Note 24 to the Consolidated Financial Statements.

Amounts Available under Shelf Registrations

At March 1, 2003, the Company had $1.325 billion of available capacity under currently effective shelf registrations with the SEC that would permit the Company to issue debt and preferred securities to meet future capital requirements.

Credit Ratings

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. Management believes that the current credit ratings of the Company provide sufficient access to the capital markets. However, disruptions in the bank and capital markets not specifically related to the Company may affect the Company's ability to access these funding sources or cause an increase in the return required by investors.

Both quantitative (financial strength) and qualitative (business or operating characteristics) factors are considered by the credit rating agencies in establishing the Company's credit ratings. Credit ratings are subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently. The credit ratings for the Company are most affected by the Company's financial profile, mix of regulated and nonregulated businesses and respective cash flows, and changes in methodologies used by the rating agencies. Credit ratings for the Company as of March 1, 2003 follow:

	Standard & Poor's	Moody's
Mortgage bonds	A-	A2
Senior unsecured (including tax-exempt) debt securities	BBB+	A3
Preferred securities of subsidiary trust	BBB	Baa1
Preferred stock	BBB	Baa2
Commercial paper	A-2	P-1

These credit ratings reflect Standard & Poor's downgrade of its credit ratings for the Company's debt, preferred securities of subsidiary trust, preferred stock and commercial paper in October 2002. Based on its conclusions about regulatory insulation in Virginia being no better than in other states, Standard & Poor's concluded that the Company's ratings should be no more than one-notch above the ratings of its parent, Dominion Resources, Inc. Standard & Poor's noted that the Company's downgrade is not reflective of any diminished credit protection measures, as the Company's credit protection measures on a stand-alone basis remain strong.

Generally, a downgrade in the Company's credit rating would not restrict its ability to raise short-term or long-term financing so long as its credit rating is still "investment grade," but it would increase the cost of borrowing. Management has been working closely with both Standard & Poor's and Moody's with the objective of maintaining the Company's current credit ratings. As discussed in *Risk Factors and Cautionary Statements That May Affect Future Results*, in order to maintain its current ratings, the Company may find it necessary to take steps or change its business plans, and such changes may adversely affect its growth.

Debt Covenants

As part of borrowing funds and issuing debt (both short-term and long-term) or preferred securities, the Company must enter enabling agreements. These agreements contain covenants that, in the event of default, could result in the acceleration of principal and interest payments; restrictions on distributions related to its capital stock to Dominion, including dividends, redemptions, repurchases, liquidation payments or guarantee payments; and, in some cases, the termination of credit commitments unless a waiver of such requirements is agreed to by the lenders/security holders. These provisions are customary, with each agreement specifying which covenants apply. These provisions are not necessarily unique to the Company. Some of the typical covenants include:

- the timely payment of principal and interest;
- information requirements, including submittal of financial reports filed with the SEC to lenders;
- keeping books and records in accordance with generally accepted accounting principles;
- payment of taxes; maintaining insurance;
- performance obligations, audits/inspections, continuation of the basic nature of business, restrictions

on certain matters related to merger or consolidation, restrictions on disposition of substantial assets;

- financial covenants, such as a limit on total funded debt to total capitalization;
- compliance with collateral minimums or requirements related to mortgage bonds (See Note 15 to the Consolidated Financial Statements); and
- limitations on liens.

The Company monitors the covenants on a regular basis in order to provide assurance that events of default will not occur. As of December 31, 2002, there were no events of default under the Company's covenants.

Investing Activities

In 2002, the Company's investing activities resulted in a net cash outflow of $857 million. These activities included plant construction and other property additions of $748 million and nuclear fuel expenditures of $59 million. Generation-related projects totaled approximately $393 million and included environmental upgrades, nuclear reactor head replacement expenditures and routine capital improvements. The Company spent approximately $322 million on transmission and distribution-related projects, reflecting routine capital improvements and expenditures associated with new connections. Other general and information technology projects totaled $33 million. Investing activities also include $36 million of contributions to the Company's nuclear decommissioning trusts. Other miscellaneous expenditures totaled $14 million.

Capital Requirements

The Company expects to fund its capital requirements and debt maturities with cash flow from operations and a combination of sales of securities and short-term borrowings.

Capacity

The Company anticipates that retail peak demand will grow approximately 1.0 percent each year through 2005, reflecting the continued growth in the number of retail customers expected to be served by the Company. However, sales under wholesale requirements contracts declined approximately $34 million in 2002 as compared to 2001, with further decreases expected as contracts expire in the future. Any future additional capacity and energy requirements through 2005 will be met primarily through market purchases.

Plant and Equipment

The Company's generation construction and nuclear fuel expenditures during 2003, 2004 and 2005 are expected to total approximately $630 million, $395 million and $325 million, respectively. The Company's annual transmission and distribution capital expenditures are expected to be approximately $55 million and $310 million, respectively, in each of the years 2003, 2004 and 2005. The Company's distribution capital expenditures will primarily provide for customer growth, reliability initiatives and routine replacements.

In early 2002 the Company completed the installation of sulfur dioxide (SO_2) emission control equipment at two coal-fired generating units at a total cost of approximately $120 million. An additional $55 million has been budgeted through 2007 for the development of future SO_2 control projects.

In response to Clean Air Act requirements, the Company is installing nitrogen oxide (NOx) reduction equipment on all of its affected facilities at an estimated capital cost of $630 million of which $370 million has been incurred as of December 31, 2002. The installations are scheduled for completion by midyear 2004. The Company is also discontinuing the use of coal at its Possum Point station in Prince William County, Virginia. Two of the Possum Point station's oil-fired units have been retired, and its two coal-fired units will be converted to gas at an estimated capital cost of $13 million, of which $5 million has been incurred as of December 31, 2002. See *Environmental Matters* for additional discussion of Clean Air Act matters.

The Company also plans to spend approximately $150 million in 2003 to complete the vessel head replacements at the North Anna and Surry nuclear stations. The total cost for this project is estimated to be $202 million, of which $52 million has been incurred as of December 31, 2002.

Contractual Cash Obligations

Presented below is a summary of the Company's contractual obligations as of December 31, 2002. These items are discussed in Notes 15, 16 and 21 to the Consolidated Financial Statements.

	Payments Due By Period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(millions)		
Long-term debt	$ 4,170	$ 360	$ 325	$ 1,480	$ 2,005
Trust preferred securities	400	—	—	—	400
Lease obligations	143	39	48	22	34
Power purchase contracts	8,606	687	1,315	1,232	5,372
Fuel and other commitments	1,062	439	411	212	—
Total	$14,381	$1,525	$2,099	$2,946	$7,811

The Company expects to fund these obligations and commitments with cash flow from operations and a combination of sales of securities and short-term borrowings. These amounts do not include planned capital expenditures or working capital commitments, such as the repayment of short-term debt and settlement of derivative and energy trading contracts, or amounts for interest or distributions payable on securities issued by the Company.

In addition, the Company has entered into agreements with another Dominion subsidiary in order to develop, construct, finance and lease a new power generation facility at the Company's Possum Point station in Prince William County, Virginia. The project is scheduled for completion in 2003 at an estimated cost of $370 million. Upon completion, the Company will operate the new generating facility under an operating lease with estimated annual lease payments of $20 million. See Note 21 to the Consolidated Financial Statements.

Future Issues and Outlook

Electric Deregulation Legislation

Virginia—Enacted in 1999, the Virginia Electric Utility Restructuring Act (the Virginia Restructuring Act) establishes a plan to restructure Virginia's electric utility industry and provides for the phase-in of choice for retail customers from January 1, 2002 through January 1, 2004. As ordered by the Virginia Commission, the Company made retail choice available for all of its Virginia regulated electric customers as of January 1, 2003.

Under the Virginia Restructuring Act, the generation portion of the Company's Virginia jurisdictional operations was no longer subject to cost-based rate regulation as of January 1, 2002. The Company's base rates (excluding fuel costs and certain other allowable adjustments) will remain capped until July 2007, unless modified or terminated sooner under the Act. Recovery of generation-related costs will continue through capped rates and, where applicable, a wires charge assessed on those customers opting for alternative suppliers. The Company may petition the Virginia Commission to terminate the capped rates after January 1, 2004. If the Company were to request that the capped rates be terminated, the Virginia Commission may terminate the capped rates if it finds that a competitive generation services market exists within the Company's service area.

Additionally, the Virginia Restructuring Act provides that after the end of the capped rate period, any default service provided by the Company will be based upon competitive market prices for electric generation services. The Virginia Commission has opened a proceeding to determine the components of default service in Virginia.

North Carolina—The North Carolina General Assembly has been exploring the future of electric service in North Carolina, the development of a competitive wholesale market and retail competition. However, to date, there has been no significant activity.

Virginia Commission Report on the Status of Competition in Virginia

In August 2002, the Virginia Commission submitted to the Governor and the Legislative Transition Task Force (Task Force) its status report on the development of a competitive retail market for electric generation within Virginia.

In an addendum to the report, the Virginia Commission recommended that state policymakers should decide promptly whether to proceed with or delay implementation of the Virginia Restructuring Act, in light of recent developments impacting electric industry restructuring in Virginia, including the FERC issuance of a notice of proposed rule making on Standard Market Design. No assessment can be made at this time concerning future developments.

Legislation that would delay entry into a regional transmission organization (RTO) until on or after July 1, 2004 was approved by the Virginia General Assembly in February 2003 and is now awaiting action by the Governor. The proposed legislation also would require the Company to file an application with the Virginia Commission by July 1, 2003 to join a RTO. Subject to Virginia Commission approval, the Company would be required to transfer management and control of its transmission assets to a RTO by January 1, 2005.

Separation of Generation and Delivery Operations in Virginia

Under the Virginia Restructuring Act, the Company separated its generation, distribution, and transmission functions through creation of divisions within the Company. Virginia codes of conduct ensure that the Company's generation and other divisions operate independently and prevent cross-subsidies between generation and other divisions.

Economic Risks and Benefits During the Transition to a Competitive Electric Marketplace in Virginia

As previously discussed, the Company will recover generation-related costs through capped rates and wires charges, where applicable, assessed to those customers opting for alternative suppliers during the transition period which extends until July 2007, unless modified or terminated earlier under the Virginia Restructuring Act. Under the Virginia Restructuring Act, the Company may request a termination of the capped rates at any time after January 1, 2004, and the Virginia Commission may grant the Company's request to terminate capped rates, if it finds that a competitive generation services market exists in the Company's service area. While the Company is exposed to certain risks as a result of the deregulation of its utility operations, it also has the opportunity to realize potential benefits during this transition period, if management is successful in preparing for the change in the environment in which its generation-related business operates.

Stranded Costs

Stranded costs are those costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market. At December 31, 2002, the Company's exposure to potentially stranded costs consisted of long-term purchased power contracts that could ultimately be determined to be above market; generating plants that could possibly become uneconomic in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits not yet recognized in the financial statements. The Company believes capped electric retail rates and, where applicable, wires charges, will provide an opportunity to recover a portion of its potentially stranded costs, depending on market prices of electricity and other factors. Recovery of the Company's potentially stranded costs remains subject to numerous risks even in the capped-rate environment. These include, among others, exposure to long-term power purchase commitment losses, future environmental compliance requirements, changes in tax laws, nuclear decommissioning costs, inflation, increased capital costs, and recovery of certain other items. These items are discussed in Notes 8 and 21 to the Consolidated Financial Statements.

The enactment of deregulation legislation in 1999 not only caused the discontinuance of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, for the Company's utility generation-related operations but also caused the Company to review its utility generation assets for impairment and long-term power purchase contracts for potential loss at that time. Significant assumptions considered in that review included possible future market prices for fuel and electricity, load growth, generating unit availability and future capacity additions in the Company's market, capital expenditures, including those related to environmental improvements, and decommissioning activities. Based on those analyses, no recognition of plant impairments or contract losses was appropriate at that time. In response to future events resulting from the development of a competitive market structure in Virginia and the expiration or termination of capped rates and wires charges, the Company may have to reevaluate its utility generation assets for impairment and long-term power purchase contracts for potential losses. Assumptions about future market prices for electricity represent a critical factor that affects the results of such evaluations. Since 1999, market prices for electricity have fluctuated significantly and will continue to be subject to volatility. Any such review in the future, which would be highly dependent on assumptions considered appropriate at that time, could possibly result in the recognition of plant impairment or contract losses that would be material to the Company's results of operations or its financial position.

In December 2002, the Task Force requested the Virginia Commission to convene a work group on stranded costs. The work group will attempt to develop a consensus methodology for determining the over- or under-recovery of stranded costs. The Virginia Commission will report the work group's findings to the Task Force by July 1, 2003. No assessment can be made at this time concerning future developments.

Changes to Cost Structure

While the Virginia Restructuring Act did not define specific generation-related costs to be recovered, it did provide generation-related cash flows (through the combination of capped rates and wires charges billed to customers) during the transition period. The generation-related cash flows provided by the Virginia Restructuring Act are intended to compensate the Company for continuing to provide generation services and to allow management to incur costs to restructure such operations during the transition period. As a result, during the transition period, the Company may realize an increased rate of return on its generation-related operations to the extent that management can favorably alter the cost structure underlying its utility generation-related operations. Conversely, the same risks affecting the recovery of the Company's stranded costs, discussed above, may also adversely impact its cost structure during the transition period. Accordingly, the Company could realize the negative economic impact of any such adverse event. In addition to managing the cost of its generation-related operations, the Company may also seek opportunities to sell available electric energy and capacity to customers beyond its electric utility service territory. Using cash flows from operations during the transition period, the Company may further alter its cost structure or choose to make additional investments in its business.

The capped rates were derived from rates established as part of the 1998 Virginia rate settlement and do not provide for specific recovery of particular generation-related expenditures, except for certain regulatory assets. See Note 10 to the Consolidated Financial Statements. To the extent that the Company manages its operations to reduce its overall operating costs below those levels contemplated by the capped rates, the Company's earnings may increase. Since the enactment of the Virginia Restructuring Act, the Company has been reviewing its cost structure to identify opportunities to reduce the annual operating expenses of its generation-related operations. For example, the Company terminated certain long-term power purchase agreements in 2001, resulting in an after-tax charge of $136 million. See Note 21 to the Consolidated Financial Statements. By avoiding fixed capacity payments that would have otherwise been required under the contracts, annual after-tax earnings will increase by $30 million during the capped rate transition period.

Also in 2002 and 2001, the Company revised the estimated useful lives of its electric generation, transmission and distribution assets. The changes in estimates were based upon expected life-extensions of nuclear plants and new studies for the other assets. As a result of these changes, annual after-tax earnings will increase by approximately $88 million during the capped rate transition period. See Note 2 to the Consolidated Financial Statements.

Regional Transmission Organization

The Virginia Restructuring Act requires that the Company join a RTO, and FERC encourages RTO formation as a means to foster wholesale market formation. FERC Order No. 2000 requires each public utility that owns or operates transmission facilities to make certain filings with respect to RTO formation, but will rely on voluntary formation of RTOs to advance its energy policies. By joining a RTO, the Company would transfer functional control of its transmission assets to a RTO, a third party.

In September 2002, the Company and PJM Interconnection, LLC (PJM) entered into the PJM South Implementation Agreement. The agreement provides that, subject to regulatory approval and certain provisions, the Company will become a member of PJM, transfer functional control of its electric transmission facilities to PJM for inclusion in a new PJM South Region, integrate its control area into the PJM energy markets and otherwise facilitate the establishment and operation of PJM as the RTO with respect to the Company's transmission facilities. The agreement also contemplates additional agreements and transmission tariff provisions to be negotiated by the parties and allocates costs of implementation of the agreement among the parties.

The Company intends to file for FERC approval to join PJM in the future. The Company will also seek authorization from the Virginia Commission and the North Carolina Commission to become a member of PJM at that time. The Company will incur integration and operating costs associated with joining a RTO. The Company has deferred certain of those costs for future recovery and is giving further consideration to seeking regulatory approval to defer the balance of such costs.

In December 2002, American Electric Power, Commonwealth Edison Company, Dayton Power and Light Company (collectively, the New PJM Companies), PJM and the Company tendered a joint filing with FERC. The joint filing proposes to (1) include the New PJM Companies' transmission facilities within PJM functional control; (2) establish a transmission rate for the existing PJM region, the Company and the New PJM Companies; (3) adopt a transitional rate method to maintain transmission revenue for the Company and the New PJM Companies and (4) amend certain agreements on file with FERC concerning the PJM energy market, planning processes and system operations as related to the integration of the New PJM Companies into PJM.

Also in December 2002, the Company filed with FERC an amendment to its open access transmission tariff to establish a transitional transmission rate method that would apply from the time American Electric Power and Commonwealth Edison Company would begin to participate under the PJM transmission tariff until the Company joins PJM.

Legislation that would delay entry into a RTO until on or after July 1, 2004 was approved by the Virginia General Assembly in February 2003 and is now awaiting action by the Governor. The proposed legislation also would require the Company to file an application with the Virginia Commission by July 1, 2003 to join a RTO. Subject to Virginia Commission approval, the Company would be required to transfer management and control of its transmission assets to a RTO by January 1, 2005.

Wholesale Competition

The Company sells electricity in the wholesale market under its market-based sales tariff authorized by FERC but has agreed not to make wholesale power sales under this tariff to loads located within its service territory. In February 2002, the Company received FERC approval of a tariff to sell wholesale power at capped rates based on its embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside its service territory. Any such sales would be voluntary.

The Company's sales of natural gas and oil in wholesale markets are not regulated by FERC.

Rate Matters

Virginia—The Company filed its Virginia Commission-approved unbundled rates reflecting the functional separation of generation, transmission and distribution in January 2002. Base rates (excluding fuel costs and certain other allowable adjustments) are capped and will remain unchanged until July 2007, unless modified or terminated sooner, as provided by the Virginia Restructuring Act. Under the Virginia Restructuring Act, the Company may request a termination of the capped rates at any time after January 1, 2004, and the Virginia Commission may grant the Company's request to terminate capped rates, if it finds that a competitive generation services market exists in the Company's service area. Where applicable, wires charges, effective January 1, 2002 and subject to annual adjustment, will be paid by the Company's Virginia jurisdictional retail customers who choose an alternative generation supplier during the capped rate period.

In October 2002, the Virginia Commission approved the Company's methodology for its 2003 market prices for generation, including a capacity adder and the resulting wires charges. The capacity adder reflects the capacity value that the sale of generation is expected to produce in addition to an energy value in market prices. Inclusion of the capacity adder in the market price calculation will reduce wires charge revenues by the amount of the expected additional revenue from the sale of the displaced capacity in the wholesale market.

The Company's fuel factor for sales to Virginia jurisdictional customers will remain unchanged for 2003.

North Carolina—The Company cannot request an increase in its North Carolina jurisdictional base rates until 2006, except for certain events that would have a significant financial impact. Fuel rates, however, are still subject to change under annual proceedings.

FERC Policy Developments

In July 2002, FERC issued proposed rules that would establish a standardized transmission service and wholesale electric market design for entities participating in wholesale electric markets. FERC proposed to exercise jurisdiction over the transmission component of bundled retail transactions, modify the existing electric transmission tariff to include a single tariff service applicable to all transmission customers and provide a standard market design for wholesale electric markets. FERC also proposed that transmission owners that have not yet joined a RTO must contract with a separate entity, an independent transmission provider, to operate their transmission facilities. FERC scheduled a number of technical conferences and meetings with interested parties and has indicated that the market design and timing of the rule is subject to change. No assessment can be made at this time concerning future developments.

FERC also continues to pursue a rulemaking that will eliminate separate standards of conduct regulations for natural gas pipelines and electric transmission utilities, and to replace these requirements with uniform standards applicable to interstate "Transmission Providers." The proposed standards would redefine the scope of affiliates covered by standards of conduct for most FERC-regulated companies. If the proposed policy is adopted, it will supersede the existing standards that are applicable to the Company. The Company supports the policy goal to ensure competitive interstate energy markets; however, the Company has advocated adjustments to the proposed rules. The Company anticipates further action by FERC in early 2003. While the Company expects the outcome of a final rule to improve its ability to compete with similarly-situated transmission providers, it does not expect a final rule to have a short-term material impact on its results of operations, financial position or cash flows.

Environmental Matters

The Company is subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

Historically, the Company recovered such costs through utility rates. However, to the extent that environmental costs are incurred in connection with operations regulated by the Virginia Commission, during the period ending June 30, 2007, in excess of the level currently included in the Virginia jurisdictional electric retail rates, the Company's results of operations will decrease. After that date, recovery through regulated rates may be sought for only those environmental costs related to regulated electric transmission and distribution operations.

Environmental Protection and Monitoring Expenditures

The Company incurred approximately $117 million, $109 million and $90 million of expenses (including depreciation) during 2002, 2001 and 2000, respectively, in connection with environmental protection and monitoring activities and expects these expenses to be approximately $115 million in 2003. In addition, capital expenditures related to environmental controls were $269 million, $197 million and $207 million for 2002, 2001 and 2000, respectively. The amount estimated for 2003 for these expenditures is $230 million.

Clean Air Act Compliance

The Clean Air Act requires the Company to reduce its emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_X), which are gaseous by-products of fossil fuel combustion. The Clean Air Act's SO_2 reduction program is based on the issuance of a limited number of SO_2 emission allowances. Each allowance permits the emission of one ton of SO_2 into the atmosphere. The allowances may be transacted with a third party. Implementation of projects to comply with SO_2 and NO_X limitations are ongoing and will be influenced by changes in the regulatory environment, availability of allowances, various state and federal control programs and emission control technology. In response to Clean Air Act requirements, the Company is installing NO_X reduction equipment on all of its affected facilities at an estimated capital cost of $630 million, of which $370 million has been incurred as of December 31, 2002. The installations are scheduled for completion by midyear 2004. The Company is also discontinuing the use of coal at its Possum Point Station in Prince William County, Virginia. Two of the Possum Point station's oil-fired units have been retired, and the two coal-fired units will be converted to gas during 2003 at an estimated capital cost of $13 million. The Company installed SO_2 emission control equipment at two coal-fired generating units during 2002 at a total cost of $120 million. An additional $55 million has been budgeted through 2007 for the development of future SO_2 control projects.

The Environmental Protection Agency (EPA) is planning to issue additional regulations to address non-attainment of the new ozone and fine particulate standards within the next few years, as well as ongoing regulatory action associated with regional haze. That regulatory action could require additional reductions in SO_2 and NO_X emissions from the Company's fossil fuel-fired generating facilities. In addition, EPA is in the process of developing a proposed standard for mercury emissions for electric utility coal-fired boilers that could require significant mercury emission reductions from all of the Company's coal-fired generating units. If these more stringent emission reduction requirements are imposed in the future, new and perhaps significant expenditures could be required. The Company cannot predict the future financial impact of implementing these potential requirements on its operations at this time.

The United States Congress is considering various "multi-pollutant" legislative proposals that would require fossil-fuel fired generating units to comply with more stringent pollution control standards for air emissions. Many of the proposals would rely upon flexible cap and trade programs for compliance and would exempt covered facilities from other Clean Air Act requirements. They would phase-in the emission reduction requirements under a variety of timeframes, up to 16 years. The Company cannot predict whether any of these proposals will pass this year or in the future. However, if more stringent emissions standards are ultimately imposed on the Company's generating units, new, perhaps significant, expenditures could be required. The Company cannot predict the future financial impact on its operations at this time.

During 2000, the Company received a Notice of Violation from the EPA, alleging that the Company failed to obtain New Source Review permits under the Clean Air Act prior to undertaking specified construction projects at the Mt. Storm Power Station in West Virginia. The Attorney General of New York filed a suit against the Company alleging similar violations of the Clean Air Act at the Mt. Storm Power Station. The Company also received notices from the Attorneys General of Connecticut and New Jersey of their intentions to file suit for similar violations. In December 2002, the Attorney General of Connecticut filed a motion to intervene as a plaintiff in the action filed by the New York State Attorney General. This action has been stayed. Management believes that the Company has obtained the necessary permits for its generating facilities. The Company has reached an agreement in principle with the federal government and the state of New York to resolve this situation. The agreement in principle includes payment of a $5 million civil penalty, a commitment of $14 million for environmental projects in Virginia, West Virginia, Connecticut, New Jersey and New York and a 12-year, $1.2 billion capital investment program for environmental improvements at the Company's coal-fired generating stations in Virginia and West Virginia. The Company had already committed to a substantial portion of the $1.2 billion expenditures for SO_2 and NO_X emissions controls. The negotiations over the terms of a binding settlement have expanded beyond the basic agreement in principle and are ongoing. As of December 31, 2002, the Company has recorded, on a discounted basis, $18 million for the civil penalty and environmental projects.

In May 2002, the EPA issued a Section 114 request for information about whether projects undertaken at the Company's Chesterfield, Chesapeake, Yorktown, Possum Point and Bremo Bluff power stations were properly permitted under the Clean Air Act's New Source Review requirements, to which the Company responded in a timely manner.

Global Climate Change

In 1997, the United States signed an international Protocol to limit man-made greenhouse emissions under the United Nations Framework Convention on Climate Change. However, the Protocol will not become binding unless approved by the U.S. Senate. Currently, the Bush Administration has indicated that it will not pursue ratification of the Protocol and has set a voluntary goal of reducing the nation's greenhouse gas emission intensity by 18 percent over the next 10 years. However, the United States Congress is considering legislation that could impose mandatory reductions of greenhouse gas emissions. The cost of compliance with the Protocol or other mandatory greenhouse gas reduction obligations could be significant for the Company. Given the highly uncertain outcome and timing of future action by the U.S. federal government on this issue, the Company cannot predict the financial impact of future climate change actions on its operations at this time.

Clean Water Act Compliance

Under authority of the Clean Water Act, the EPA is promulgating new regulations governing utilities that employ a cooling water intake structure, with flow levels that exceed a minimum threshold. As currently written, the EPA's proposed rule presents several control options under consideration for the final rule. The Company is evaluating facility information from Bremo, Chesapeake, Chesterfield, Mt. Storm, North Anna, Possum Point, Surry and Yorktown power stations. Given the uncertainties of future action by the EPA on this issue, the Company cannot predict the future impact on its operations at this time.

Accounting Matters

The FASB has issued several new standards that will affect the Company beginning in 2003. These include: SFAS No. 143, *Accounting for Asset Retirement Obligations*; Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Others—An Interpretation of FASB Statements No 5, 57 and 107*, and Interpretation No. 46, *Consolidation of Variable Interest Entities*. In addition, the EITF rescinded EITF Issue No. 98-10. See Note 4 to the Consolidated Financial Statements for further discussion of the impact of adopting these new accounting standards and information about other standard-setting activities.

Outlook for 2003

The Company believes its operating businesses will provide growth in earnings in 2003. However, reported earnings for 2003 will also include the effects of severance costs under the workforce reduction plan discussed below and the cumulative effect of implementing changes in accounting for asset retirement obligations and energy trading activities. See Note 4 to the Consolidated Financial Statements. The 2003 projections for the Company's operating businesses anticipate continued growth in electric utility service customers, which would be, however, offset by higher pension benefit expense and the effect of assuming normal weather, as compared to 2002.

Other Matters

Pension Costs

As discussed in Note 20 to the Consolidated Financial Statements, the Company participates in the Dominion pension plan, a qualified noncontributory defined benefit retirement plan. As a participating employer, the Company is subject to Dominion's funding policy, which is to generally contribute annually an amount that is in accordance with the provisions of the Employment Retirement Income Security Act of 1974. Investment experience and market conditions, including interest rates, impact the measurement of these benefit obligations and the cost of providing such benefits. Accordingly, assumptions for discount rates and the expected long-term rate of return on investments are important considerations under SFAS No. 87, *Employers' Accounting for Pensions*. However, since the objective of SFAS No. 87 is to recognize the cost of providing benefits over employees' service period, it permits the delayed recognition of certain elements of retirement plan results.

Dominion has reviewed the assumption used for expected long-term rate of return on plan assets to better reflect anticipated future market conditions and has adopted an expected rate of 8.75 percent for 2003. This change, combined with other factors such as a revised discount rate assumption of 6.75 percent for 2003, will increase the Company's 2003 pension expense by an estimated $22 million, as compared to 2002. In addition, in order to maintain the funded status of Dominion's retirement plans, Dominion and its subsidiaries, including the Company, may have to contribute increased amounts to the plans in future years.

Workforce Reductions

In connection with a plan announced by Dominion in January 2003, the Company expects to eliminate some union and salaried jobs during 2003. The workforce reductions will affect primarily support positions including meter readers, supply and warehouse workers and auto mechanics. Many of the reductions result from investments in automated meter-reading technology and purchases of newer, lower maintenance vehicles. Affected workers will be offered severance packages, and benefits for union workers will be negotiated during 2003. Pending completion of the process to identify affected positions, the Company has not estimated the cost of the workforce reductions.

Change in Composition of Operating Segments

Effective January 1, 2003, the Company's electric transmission operations will be reported as a part of the Energy segment instead of the Delivery segment.

Nuclear Relicensing

The Company filed applications for 20-year life-extensions for the North Anna and Surry units in May 2001 with the NRC. The NRC has completed its review of the applications. The Company expects to receive a renewed license for these units in 2003.

Nuclear Insurance

The Price-Anderson Act expired in August 2002, but operating nuclear reactors would continue to be covered by the law, which would channel and cap claims if a nuclear accident should occur. The Act has been renewed three times since 1957, and Congress is currently holding hearings to reauthorize the legislation. The expiration of the Act does not impact the coverage of existing nuclear license holders.

Effect of Changes in Commodity Prices

The Company's operations are impacted by changes in energy commodity prices. To the extent that energy commodities are sold by the Company and such sales are subject to cost-of-service rate regulation, the commodity costs are generally recovered through rates. Market price changes impact the Company's revenues from commodity sales through unregulated subsidiaries. The Company has established an enterprise risk management function to evaluate these risks and to recommend actions to management that are intended to mitigate such risks.

Market Rate Sensitive Instruments and Risk Management

The Company's financial instruments, commodity contracts and related derivative instruments are exposed to potential losses due to adverse changes in interest rates, foreign currency exchange rates, commodity prices and equity security prices, as described below. Interest rate risk generally is related to the Company's outstanding debt. The Company is exposed to foreign exchange risk associated with purchases of certain nuclear fuel services denominated in foreign currencies. Commodity price risk is present in the Company's electric operations and energy marketing and trading operations due to the exposure to market shifts for prices received and paid for natural gas, electricity and other commodities. The Company uses derivative instruments to manage price risk exposures for these operations. The Company is exposed to equity price risk through various portfolios of equity securities.

The Company's sensitivity analysis estimates the potential loss of future earnings or fair value from market risk sensitive instruments over a selected time period due to a 10 percent unfavorable change in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk—Trading Activities

As part of its strategy to market energy and to manage related risks, the Company manages a portfolio of commodity-based derivative instruments held for trading purposes. These contracts are sensitive to changes in the prices of natural gas, electricity and certain other commodities. The Company uses established policies and procedures to manage the risks associated with these price fluctuations and uses derivative instruments, such as futures, forwards, swaps and options, to mitigate risk by creating offsetting market positions. In addition, the Company seeks to use its generation capacity, when not needed to serve customers in its service territory, to satisfy commitments to sell energy.

A hypothetical 10 percent unfavorable change in commodity prices would have resulted in a decrease of approximately $30 million and $7 million in the fair value of its commodity contracts held for trading purposes as of December 31, 2002 and 2001, respectively.

Interest Rate Risk

The Company manages its interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. The Company also enters into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For financial instruments outstanding at December 31, 2002, a hypothetical 10 percent increase in market interest rates would decrease annual earnings by approximately $2 million. A hypothetical 10 percent increase in market interest rates, as determined at December 31, 2001, would have resulted in a decrease in annual earnings of approximately $2 million.

Foreign Exchange Risk

The Company manages its foreign exchange risk exposure associated with anticipated future purchases of nuclear fuel uranium enrichment services denominated in foreign currencies by utilizing currency forward contracts. As a result of holding these contracts as hedges, the Company's exposure to foreign currency risk is minimal. A hypothetical 10 percent unfavorable change in relevant foreign exchange rates would have resulted in a decrease of approximately $17 million and $5 million in the fair value of currency forward contracts held by the Company at December 31, 2002 and 2001, respectively.

Investment Price Risk

The Company is subject to investment price risk due to marketable securities held as investments in decommissioning trust funds. In accordance with current accounting standards, these marketable securities are reported on the Consolidated Balance Sheets at fair value. As described in Note 8 to the Consolidated Financial Statements, the Company recognized net realized and unrealized losses on decommissioning trust investments of $56 million for 2002 and $29 million for 2001.

Dominion also sponsors employee pension and other postretirement benefit plans, in which the Company's employees participate, that hold investments in trusts to fund benefit payments. To the extent that the values of investments held in these trusts decline, the effect will be reflected in the Company's recognition of the periodic cost of such employee benefit plans and the determination of the amount of cash to be contributed by the Company to the employee benefit plans.

Risk Management Policies

The Company has operating procedures in place that are administered by experienced management to help ensure that proper internal controls are maintained. In addition, Dominion has established an independent function at the corporate level to monitor compliance with the risk management policies of all subsidiaries. Dominion maintains credit policies that include the evaluation of a prospective counterparty's financial condition, collateral requirements, where deemed necessary, and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, Dominion also monitors the financial condition of existing counterparties on an ongoing basis. Management believes, based on Dominion's credit policies and the Company's December 31, 2002 provision for credit losses, that it is unlikely that a material adverse effect on the Company's financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

See *Risk Factors and Cautionary Statements That May Affect Future Results* and *Market Rate Sensitive Instruments and Risk Management* in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Item 8. Financial Statements and Supplementary Data

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Report of Management

The Company's management is responsible for all information and representations contained in the Consolidated Financial Statements and other sections of the Company's annual report on Form 10-K. The Consolidated Financial Statements, which include amounts based on estimates and judgments of management, have been prepared in conformity with accounting principles generally accepted in the United States of America. Other financial information in the Form 10-K is consistent with that in the Consolidated Financial Statements.

Management maintains a system of internal controls designed to provide reasonable assurance, at a reasonable cost, that the Company's assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. Management recognizes the inherent limitations of any system of internal control and, therefore, cannot provide absolute assurance that the objectives of the established internal controls will be met. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits. Management believes that during 2002 the system of internal control was adequate to accomplish the intended objectives.

The Consolidated Financial Statements have been audited by Deloitte & Touche LLP, independent auditors, who have been engaged by the Board of Directors. Their audits were conducted in accordance with auditing standards generally accepted in the United States of America and included a review of the Company's accounting systems, procedures and internal controls to the extent necessary for the purpose of its report.

The Audit Committee of the Board of Directors of Dominion Resources, Inc. (the Company's parent), composed entirely of directors who are not officers or employees of Dominion Resources, Inc. or its subsidiaries, meets periodically with the independent auditors, the internal auditors and management to discuss auditing, internal accounting control and financial reporting matters of the Company and to ensure that each is properly discharging its responsibilities. Both the independent auditors and the internal auditors periodically meet alone with the Audit Committee and have free access to the Committee at any time.

Virginia Electric and Power Company

/s/ G. Scott Hetzer	/s/ Steven A. Rogers
G. Scott Hetzer	Steven A. Rogers
Senior Vice President and Treasurer	Vice President
(Principal Financial Officer)	*(Principal Accounting Officer)*

Independent Auditors' Report

To the Board of Directors of
Virginia Electric and Power Company
Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of income, comprehensive income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 Virginia Electric and Power Company and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 9 to the consolidated financial statements, effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. Also, as discussed in Note 3 to the consolidated financial statements, the Company changed its method of accounting used to develop the market-related value of pension plan assets in 2000.

/s/ DELOITTE & TOUCHE LLP

Richmond, Virginia
January 21, 2003

Virginia Electric and Power Company
Consolidated Statements of Income

	Year Ended December 31,		
	2002	2001	2000
		(millions)	
Operating Revenue	$4,972	$4,944	$4,791
Operating Expenses			
Electric fuel and energy purchases, net	1,281	1,252	1,104
Purchased electric capacity	691	680	740
Restructuring costs	(7)	48	71
Other operations and maintenance	900	1,268	957
Depreciation and amortization	495	518	558
Other taxes	152	179	275
Total operating expenses	3,512	3,945	3,705
Income from operations	1,460	999	1,086
Other income	32	33	47
Interest and related charges:			
Interest expense	275	289	285
Distributions—preferred securities of subsidiary trust	19	11	11
Total interest and related charges	294	300	296
Income before income taxes	1,198	732	837
Income taxes	425	286	279
Income before cumulative effect of a change in accounting principle	773	446	558
Cumulative effect of a change in accounting principle (net of income taxes of $11)	—	—	21
Net income	773	446	579
Preferred dividends	16	23	36
Balance available for common stock	$ 757	$ 423	$ 543

The accompanying notes are an integral part of the Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Balance Sheets

	At December 31,	
	2002	2001
	(millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 132	$ 84
Accounts receivable:		
Customers (less allowance for doubtful accounts of $12 in 2002 and $23 in 2001)	1,758	1,105
Other	73	57
Receivables from affiliates	41	54
Inventories (average cost method)		
Materials and supplies	166	163
Fossil fuel	133	149
Gas stored	147	59
Derivative and energy trading assets	1,261	1,039
Prepayments	47	140
Other	108	71
Total current assets	3,866	2,921
Investments		
Nuclear decommissioning trust funds	838	858
Other	22	25
Total investments	860	883
Property, Plant and Equipment		
Property, plant and equipment	17,797	17,232
Less accumulated depreciation and amortization	8,240	7,985
Total property, plant and equipment, net	9,557	9,247
Deferred Charges and Other Assets		
Intangible assets, net	129	113
Regulatory assets, net	239	231
Derivative and energy trading assets	402	323
Other	110	66
Total deferred charges and other assets	880	733
Total assets	$15,163	$13,784

The accompanying notes are an integral part of the Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Balance Sheets (Continued)

	At December 31, 2002	At December 31, 2001
	(millions)	
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Securities due within one year	$ 360	$ 535
Short-term debt	443	436
Accounts payable, trade	1,591	1,014
Payables to affiliates	56	192
Affiliated current borrowings	100	—
Accrued interest, payroll and taxes	207	214
Derivative and energy trading liabilities	1,206	1,010
Other	206	218
Total current liabilities	4,169	3,619
Long-Term Debt	3,794	3,704
Deferred Credits And Other Liabilities		
Deferred income taxes	1,667	1,537
Deferred investment tax credits	96	113
Derivative and energy trading liabilities	279	246
Other	170	170
Total deferred credits and other liabilities	2,212	2,066
Total liabilities	10,175	9,389
Commitments And Contingencies (See Note 21)		
Company Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust[1]	400	135
Preferred Stock Not Subject To Mandatory Redemption	257	384
Common Shareholder's Equity		
Common stock, no par, authorized—300,000 shares; outstanding—177,932 shares at 2002 and 171,484 at 2001	2,888	2,738
Other paid-in capital	16	14
Accumulated other comprehensive income (loss)	8	(4)
Retained earnings	1,419	1,128
Total common shareholder's equity	4,331	3,876
Total liabilities and shareholder's equity	$15,163	$13,784

(1) As described in Note 16 to Consolidated Financial Statements, the debt securities issued by Virginia Electric and Power Company constitute 100 percent of the Trust's assets.

The accompanying notes are an integral part of the Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Statements of Common Shareholder's Equity

	Common Stock Shares	Common Stock Amount	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
	(shares in thousands, all other amounts in millions)					
Balance at January 1, 2000	172	$2,738	$17		$ 988	$3,743
Comprehensive income					579	579
Dividends and other adjustments					(444)	(444)
Other			(1)		(28)	(29)
Balance at December 31, 2000	172	2,738	16		1,095	3,849
Comprehensive income (loss)				$ (4)	446	442
Dividends and other adjustments			(2)		(413)	(415)
Balance at December 31, 2001	172	2,738	14	(4)	1,128	3,876
Issuance of stock to parent	6	150				150
Tax benefit from stock options exercised			1			1
Comprehensive income				12	773	785
Dividends and other adjustments			1		(482)	(481)
Balance at December 31, 2002	178	$2,888	$16	$ 8	$1,419	$4,331

The accompanying notes are an integral part of the Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,	
	2002	2001
	(millions)	
Net income	$773	$446
Other comprehensive income, net of taxes:		
Net deferred gains (losses) on derivatives—hedging activities, net of tax (expense) benefit of $(4) and $1	7	(1)
Cumulative effect of a change in accounting principle, net of tax benefit of $9		(14)
Amounts reclassified to net income:		
Net losses on derivatives—hedging activities, net of tax expense (benefit) of $(2) and $(7)	5	11
Other comprehensive income (loss)	12	(4)
Comprehensive income	$785	$442

The Company's net income was $579 million for 2000. The Company had no other comprehensive income reportable for that year in accordance with SFAS No. 130, *Reporting Comprehensive Income.*

The accompanying notes are an integral part of the Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2002	2001	2000
		(millions)	
Operating Activities			
Net income	$ 773	$ 446	$ 579
Adjustments to reconcile net income to net cash from operating activities:			
Cumulative effect of a change in accounting principle, net of income taxes			(21)
Depreciation and amortization	570	588	637
Deferred income taxes and investment tax credits	97	51	10
Deferred fuel expenses, net	(20)	(24)	(33)
Changes in:			
Accounts receivable	(669)	54	(496)
Affiliated accounts receivable and payable	(16)	46	94
Inventories	(75)	(140)	4
Prepayments	138	(36)	(48)
Accounts payable, trade	577	132	365
Accrued interest, payroll and taxes	(5)	(23)	5
Other	(98)	(13)	(2)
Net cash provided by operating activities	1,272	1,081	1,094
Investing Activities			
Plant construction and other property additions	(748)	(668)	(652)
Nuclear fuel	(59)	(83)	(82)
Nuclear decommissioning contributions	(36)	(36)	(36)
Other	(14)	54	—
Net cash flows used in investing activities	(857)	(733)	(770)
Financing Activities			
Issuance (repayment) of short-term debt, net	7	(278)	336
Short-term borrowings from parent, net	100	—	—
Issuance of preferred securities of subsidiary trusts	400	—	—
Repayment of preferred securities of subsidiary trusts	(135)	—	—
Issuance of long-term debt and preferred stock	658	770	250
Repayment of long-term debt and preferred stock	(887)	(473)	(376)
Common stock dividend payments	(467)	(392)	(408)
Preferred stock dividend payments	(15)	(25)	(36)
Other	(28)	(7)	(11)
Net cash flows used in financing activities	(367)	(405)	(245)
Increase (decrease) in cash and cash equivalents	48	(57)	79
Cash and cash equivalents at beginning of year	84	141	62
Cash and cash equivalents at end of year	$ 132	$ 84	$ 141
Supplemental Cash Flow Information			
Cash paid for			
Interest and related charges, excluding amounts capitalized	$ 278	$ 298	$ 302
Income taxes	165	145	331
Non-cash transactions from financing activities:			
Non-cash exchange of mortgage bonds for senior notes	117	—	—
Issuance of common stock in exchange for reduction in amounts payable to parent	150	—	—
Conveyance of telecommunications subsidiary to parent, net of cash	—	—	19

The accompanying notes are an integral part of the Consolidated Financial Statements.

Virginia Electric and Power Company
Notes to Consolidated Financial Statements

Note 1. Nature of Operations

Virginia Electric and Power Company (Virginia Power or the Company), a Virginia public service company, is a wholly-owned subsidiary of Dominion Resources, Inc. (Dominion). The Company is a regulated public utility that generates, transmits and distributes electric energy within a 30,000 square-mile area in Virginia and northeastern North Carolina. It sells electricity to approximately 2.2 million retail customers, including governmental agencies, and to wholesale customers such as rural electric cooperatives, municipalities, power marketers and other utilities. The Virginia service area comprises about 65 percent of Virginia's total land area but accounts for over 80 percent of its population. The Company has trading relationships beyond the geographic limits of its retail service territory and buys and sells wholesale electricity and natural gas off-system. Within this document, the term "Company" refers to the entirety of Virginia Electric and Power Company, including its Virginia and North Carolina operations, and all of its subsidiaries.

The Company manages its daily operations along two operating segments, Energy and Delivery. The Energy segment encompasses the Company's portfolio of generating facilities and power purchase contracts and its trading and marketing activities. The Delivery segment includes bulk power transmission, distribution and metering services and customer service. The Delivery segment is subject to cost-of-service rate regulation and Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71). Effective January 1, 2003, the Company's electric transmission operations will be managed by the Energy segment instead of the Delivery segment.

Note 2. Significant Accounting Policies

General

The Company makes certain estimates and assumptions in preparing its Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles). These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the periods presented. Actual results may differ from those estimates.

The Consolidated Financial Statements represent the Company's accounts after the elimination of intercompany transactions.

Certain amounts in the 2001 and 2000 Consolidated Financial Statements have been reclassified to conform to the 2002 presentation.

Use of Fair Value Measurements

The Company reports certain contracts and instruments at fair value in accordance with applicable generally accepted accounting principles. Fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, the Company must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis.

For options and contracts with option-like characteristics where pricing information is not available from external sources, the Company uses a modified Black-Scholes model and considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. For contracts with unique characteristics, the Company estimates fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. If pricing information is not available from external sources, judgment is required to develop the estimates of fair value. For individual contracts, the use of different assumptions could have a material effect on the contract's estimated fair value.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. Revenue from energy trading activities includes realized commodity contract revenue, net of related cost of sales, and unrealized gains and losses from marking to market those commodity contracts not yet settled. See Note 5. Beginning October 25, 2002 and January 1, 2003, in accordance with new accounting requirements as discussed further in Note 4, the Company discontinued marking to market unsettled commodity contracts that are not otherwise accounted for as derivatives under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*.

Electric Fuel and Purchased Energy—Deferred Costs

Where permitted by regulatory authorities, the differences between actual electric fuel and purchased energy and the levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. Approximately 94 percent of rate regulated fuel costs are subject to deferral accounting. See *Regulatory Assets and Liabilities* below and Note 10.

Income Taxes

The Company files a consolidated federal income tax return and participates in an intercompany tax allocation agreement with Dominion and its subsidiaries. The Company's current income taxes are based on its taxable income, determined on a separate company basis. However, under the Public Utility Holding Company Act of 1935 (1935 Act) and the intercompany tax allocation agreement, the Company's cash payments to Dominion are reduced for a portion of income tax benefits realized by Dominion as a result of filing consolidated returns. Where permitted by regulatory authorities, the treatment of temporary differences can differ from the requirements of SFAS No. 109, *Accounting for Income Taxes*. Accordingly, a regulatory asset has been recognized if it is probable that future revenues will be provided for the payment of deferred tax liabilities. Deferred investment tax credits are being amortized over the service lives of the property giving rise to such credits.

Stock-based Compensation

Employees of the Company may receive stock-based awards, such as stock options and restricted stock, granted under Dominion-sponsored stock plans. The Company measures compensation cost for stock-based awards issued to its employees in accordance with Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Compensation expense is measured based on the intrinsic value, the difference between fair market value of Dominion common stock and the exercise price of the underlying award, on the date when both the price and number of shares the recipient is entitled to receive are known, generally the grant date. Compensation expense, if any, is recognized on a straight-line basis over the stated vesting period of the award. Compensation expense associated with these awards was not material in 2002, 2001 and 2000. The pro forma impact on net income, had the Company measured compensation expense based on the fair value of the options on the date of grant, would not have been material for 2002, 2001 and 2000.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until actually presented for payment. At December 31, 2002 and 2001, the Company's accounts payable included the net effect of checks outstanding but not yet presented for payment of $39 million and $100 million, respectively. For purposes of the Consolidated Statements of Cash Flows, the Company considers cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with a remaining maturity of three months or less.

Margin Deposit Assets and Liabilities

Amounts reported as margin deposit assets represent funds held on deposit by various trading counterparties that resulted from the Company exceeding agreed-upon credit limits established by the counterparties. Amounts reported as margin deposit liabilities represent funds held by the Company that resulted from various trading counterparties exceeding agreed-upon credit limits established by the Company. These credit limits and the mechanism for calculating the amounts to be held on deposit are determined in the International Swap Dealers Association master agreements and the Master Power Purchase and Sale Agreement of the Edison Electric Institute in place between the Company and the counterparties. As of December 31, 2002 and December 31, 2001, the Company had margin deposit assets of $52 million and $10 million, respectively. Margin deposit liabilities were $22 million at December 31, 2002, and there were no margin deposit liabilities at December 31, 2001. These amounts are reflected in other current assets and other current liabilities.

Property, Plant and Equipment

Property, plant and equipment, including additions and replacements, is recorded at original cost, including labor, materials, other direct costs and capitalized interest. The costs of repairs and maintenance, including minor additions and replacements, are charged to expense as incurred. In 2002, 2001 and 2000, the Company capitalized interest costs of $17 million, $20 million and $18 million, respectively.

For electric distribution and transmission property subject to cost-of-service utility rate regulation, the cost of such property and related cost of removal, less salvage, are charged to accumulated depreciation at retirement. For generation-related property, cost of removal is charged to expense as incurred. The Company records gains and losses upon retirement of generation-related property based upon the difference between proceeds received, if any, and the property's undepreciated basis at the retirement date.

Depreciation of property, plant and equipment is computed on the straight-line method based on projected service lives. The Company's depreciation rates on property, plant and equipment for 2002, 2001 and 2000 are as follows: generation—1.88 percent, 2.10 percent, 2.80 percent, respectively; transmission—2.14 percent, 2.75 percent, 2.74 percent, respectively; distribution—3.55 percent, 3.77 percent, 3.81 percent, respectively; and general—5.24 percent, 4.30 percent, 4.46 percent, respectively. Amortization of nuclear fuel used in electric generation is provided on a unit-of-production basis sufficient to fully amortize, over the estimated service life, the cost of the fuel plus permanent storage and disposal costs.

In 2002, the Company extended the estimated useful lives of most of its fossil fuel stations and electric transmission and distribution property based on depreciation studies that indicated longer lives were appropriate. These changes in estimated useful lives reduced depreciation expense by approximately $40 million for the entirety of 2002 and will reduce depreciation expense approximately $64 million on an annual basis thereafter. In 2001, the Company increased its estimate of the useful lives of its nuclear facilities by 20 years, which reduced depreciation expense by approximately $72 million for the entirety of 2001 and on an annual basis thereafter. This change in estimate was made in connection with the filing of applications for license extensions with the Nuclear Regulatory Commission (NRC).

For a discussion of a change in the accounting for future decommissioning costs, see *Asset Retirement Obligations* in Note 4.

Derivative Instruments

The Company uses derivative instruments such as futures, swaps, forwards and options to manage the commodity, currency exchange and financial market risks of its business operations. The Company also manages a portfolio of commodity contracts held for trading purposes as part of its strategy to market energy and to manage related risks. Derivative instruments are generally recognized on the Consolidated Balance Sheets at fair value. See Note 9 for further discussion of the Company's use of derivative instruments and energy trading contracts, including its risk management policy, its accounting policy for derivatives under SFAS No. 133 and the results of its hedging activities for the years ended December 31, 2002 and 2001.

Prior to January 1, 2001, the Company considered derivative instruments to be effective hedges when the item being hedged and the underlying financial instrument or commodity contract showed strong historical correlation. The Company used deferral accounting to account for futures, forwards and other derivative instruments that were designated as hedges. Under this method, realized gains and losses (including the payment of any premium) related to effective hedges of existing assets and liabilities were recognized in earnings in conjunction with the designated asset or liability. Gains and losses related to effective hedges of firm commitments and anticipated transactions were included in the measurement of the subsequent transaction.

Impairment of Long-Lived and Intangible Assets

The Company performs an evaluation for impairment whenever events or changes in circumstances indicate that the carrying amount of long-lived assets or intangible assets with finite lives may not be recoverable. These assets are written down to fair value if the sum of the expected future undiscounted cash flows is less than the carrying amounts.

Regulatory Assets and Liabilities

Methods of allocating costs to accounting periods for operations subject to federal or state cost-of-service rate regulation may differ from accounting methods generally applied by nonregulated companies. The economic effects of allocations prescribed by regulatory authorities for rate-making purposes must be considered in the application of generally accepted accounting principles. See Notes 10 and 21 for additional information on regulatory assets and liabilities and the impact of legislation on continued application of SFAS No. 71.

Amortization of Debt Issuance Costs

The Company defers and amortizes debt issuance costs and debt premiums or discounts over the lives of the respective debt issues. As permitted by regulatory authorities, gains or losses resulting from the refinancing of debt allocable to utility operations subject to cost-based rate regulation have also been deferred and amortized over the lives of the new issues.

Note 3. Accounting Change for Pension Costs

Effective January 1, 2000 and in connection with Dominion's acquisition of the Consolidated Natural Gas Company (CNG), Dominion and its subsidiaries, including the Company, adopted a new company-wide method of calculating the market-related value of pension plan assets used to determine the expected return on pension plan assets, a component of net periodic pension cost. Management believes the new method enhances the predictability of the expected return on pension plan assets; provides consistent treatment of all investment gains and losses; and results in calculated market-related pension plan asset values that are closer to market value than the values calculated under the pre-acquisition methods used by Dominion and CNG.

As the primary participating employer in the Dominion Resources Retirement Plan in 2000, the Company recorded its proportionate share of the cumulative effect of the change in accounting principle, $21 million (net of income taxes of $11 million). Other than the impact of the cumulative effect of the change in accounting principle, the effect of the change on net income for 2000 was not material.

Note 4. Recently Issued Accounting Standards

Asset Retirement Obligations

In 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, which provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. The Company adopted the standard effective January 1, 2003.

The Company has identified certain asset retirement obligations that are subject to the standard. These obligations are primarily associated with the decommissioning of its nuclear generation facilities.

Under SFAS No. 143, asset retirement obligations will be recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Under the present value approach used to estimate the fair value of asset retirement obligations, accretion of the liabilities due to the passage of time will be recognized as an operating expense. As a result, the adoption of SFAS No. 143 requires changes in the Company's accounting and reporting for certain asset retirement obligations already being recognized under its accounting policies prior to the adoption of SFAS No. 143. For example, the Company already recognizes amounts related to future decommissioning activities at its utility nuclear plants. As discussed in Note 8, the accumulated provision for decommissioning is presented on the balance sheet at December 31, 2002 as a component of accumulated depreciation. Under SFAS No. 143, the asset retirement obligation will be reported as a liability.

In addition, the reporting of realized and unrealized earnings of external trusts available for funding decommissioning activities at the Company's nuclear plants will be recorded in other income and other comprehensive income, as appropriate. Through 2002, the Company recorded these trusts' earnings in other income with an offsetting charge to expense, also recorded in other income, for the accretion of the decommissioning liability.

On January 1, 2003, the Company implemented SFAS No. 143 and recognized an after-tax gain of $139 million, representing the cumulative effect of a change in accounting principle. Under the Company's accounting policy prior to the adoption of SFAS No. 143, $838 million had previously been accrued for future asset removal costs, primarily related to future nuclear decommissioning. Such amounts are included in the accumulated provision for depreciation and amortization as of December 31, 2002. With the adoption of SFAS No. 143, the Company calculated its asset retirement obligations to be $697 million. In recording the cumulative effect of the accounting change, the Company recognized the reduction attributable to the re-measurement of asset retirement obligations and reclassified such amount from the accumulated provision for depreciation and amortization to other non-current liabilities. The cumulative effect of the accounting change also reflected a $175 million increase in property, plant and equipment for capitalized asset retirement costs and a $77 million increase in the accumulated provision for depreciation and amortization, representing the depreciation of such costs through December 31, 2002.

In accordance with SFAS No. 71, the Company will continue its practice of accruing for future costs of removal for its cost-of-service rate regulated electric transmission and distribution assets, even if no legal obligation to perform such activities exists. At December 31, 2002, the Company's accumulated depreciation and amortization included $375 million, representing the estimated costs of such removal activities.

Energy Trading Contracts

In October 2002, the Emerging Issues Task Force (EITF) rescinded EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities* (EITF 98-10). As a result, certain energy-related commodity contracts held for trading purposes will no longer be subject to fair value accounting. The affected contracts are those energy-related contracts, held for trading purposes that are not considered derivatives under SFAS No. 133. Under EITF 98-10 accounting, the fair value of energy contracts was measured at each reporting date, with changes in fair value, including unrealized amounts, reported in earnings. Energy-related contracts affected by the rescission of EITF 98-10 will be subject to accrual accounting and recognized as revenue or expense at the time of contract performance, settlement or termination.

The rescission of EITF 98-10 primarily affects the timing of recognition in earnings from the Company's energy-related trading contracts. In addition, affected contracts will no longer be reported at fair value on the Company's balance sheet. The EITF 98-10 rescission was effective for all non-derivative energy trading contracts initiated after October 25, 2002. As a result of implementing the change for all non-derivative energy trading contracts initiated prior to October 25, 2002, the Company recognized a loss of $55 million (net of taxes of $35 million) as the cumulative effect of this change in accounting principle effective January 1, 2003.

Accounting For Guarantees

In November 2002, FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others—An Interpretation of FASB Statements No. 5, 57 and 107.* Under the Interpretation, issuers of certain types of guarantees must recognize a liability based on the fair value of the guarantee issued, even when the likelihood of making payments is remote. In addition, the Interpretation requires increased disclosures for specific types of guarantees.

The Interpretation's initial recognition requirements apply only to guarantees issued or modified after December 31, 2002. The Company does not anticipate any material impact on its future results of operations or financial condition as a result of recording newly issued or modified guarantees at fair value. The Interpretation's disclosure requirements are effective for financial statements ending after December 15, 2002.

Consolidation of Variable Interest Entities

In January 2003, FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities*, which addresses consolidation by business enterprises of entities that are not controllable through voting interests or in which the equity investors do not bear the residual economic risks and rewards. These entities have been commonly referred to as "special purpose entities." The underlying principle behind the new Interpretation is that if a business enterprise has the majority financial interest in an entity, defined in the guidance as a variable interest entity, the assets, liabilities, and results of the activities of the variable interest entity should be included in consolidated financial statements with those of the business enterprise. The Interpretation explains how to identify variable interest entities and how an enterprise should assess its interest in an entity to decide whether to consolidate that entity. The Company will apply the provisions of the Interpretation prospectively for all variable interest entities created after January 31, 2003. For variable interest entities created before January 31, 2003, the Company will be required to consolidate all entities in which it was deemed to be the primary beneficiary beginning July 1, 2003. The Company does not anticipate that the adoption of the Interpretation will have a material impact on its results of operations or financial condition.

SFAS No. 133 Guidance

In connection with the January 2003 EITF meeting, FASB was requested to reconsider an interpretation of SFAS No. 133. The interpretation, which is contained in the Derivatives Implementation Group's C11 guidance, relates to contracts with pricing terms that include broad market indices. In particular, that guidance discusses whether the pricing in a contract that contains broad market indices (e.g., consumer price index) could qualify as a normal purchase or sale and therefore not be subject to fair value accounting. The Company has certain power purchase and sale contracts that are subject to the guidance addressed in the request for reconsideration. The aggregate fair value of these contracts at December 31, 2002 represented an estimated pretax net unrealized loss of $120 million. The Company is currently evaluating the implementation that would ultimately be required as a result of the guidance being clarified. When these Company contracts are considered with other Dominion subsidiaries' contracts that are subject to the guidance, Dominion estimates that the aggregate fair value of the contracts is not a material amount.

Note 5. Operating Revenue

	Year Ended December 31,		
	2002	2001	2000
		(millions)	
Regulated electric sales	$4,857	$4,620	$4,492
Other	115	324	299
Total operating revenue	$4,972	$4,944	$4,791

Regulated electric sales consist primarily of state-regulated retail electric sales and federally-regulated wholesale electric sales and electric transmission services subject to cost-of-service rate regulation. The Company's customer accounts receivable at December 31, 2002 and 2001 includes $231 million and $181 million, respectively, of accrued unbilled revenue based on estimated electric energy delivered but not yet billed to its utility customers. Considering historical usage and applicable customer rates, the Company estimates unbilled utility revenue based on total daily electric generation supplied, after adjusting for estimated losses of energy during transmission, and weather factors.

Other revenue includes revenue from energy trading activities, sales of electricity and natural gas at market-based rates, brokered gas sales, service fees associated with rate-regulated electric distribution and other miscellaneous revenue. Revenue from energy trading activities includes realized contract settlements, net of related cost of sales, and unrealized gains and losses resulting from marking to market those commodity contracts not yet settled.

Note 6. Restructuring Costs

2001 Restructuring Costs

In the fourth quarter of 2001, after fully integrating CNG into Dominion's existing organization and operations, including those of the Company, management initiated a focused review of Dominion's combined operations and developed a plan of reorganization. As a result, the Company recognized $48 million of restructuring costs which included employee severance and termination benefits and the abandonment of leased office space no longer needed.

The Company recorded $42 million in total severance and related costs, including $26 million billed to the Company by Dominion Resources Services, Inc. (Dominion Services). Under the 2001 restructuring plan, the Company identified 124 positions to be eliminated and recorded $16 million in employee severance-related costs. Severance payments were based on the individual's base salary and years of service at the time of termination. In 2002, the Company recorded a $7 million adjustment to the liability for severance and related costs and reported it in restructuring costs in the Consolidated Statement of Income. With 89 positions actually being eliminated under the plan, the adjustment reflected a reduction in the number of employee positions being eliminated and a reduction for differences between actual and estimated base salaries and years of service for those employees actually terminated under the plan.

Restructuring and related costs for the year ended December 31, 2001 were as follows:

	(millions)
Severance and related costs	$16
Severance and related costs—Dominion Services[1]	26
Other[2]	6
Total restructuring costs	$48

[1] Dominion Services, a subsidiary service company under the 1935 Act, provides certain services to Dominion's operating subsidiaries. Accordingly, charges are allocated and billed among the operating subsidiaries in accordance with predefined service agreements. See Note 24.

[2] Includes charges for abandonment of leased office space and related costs by the Company and Dominion Services.

The change in the liability for severance and related costs during 2002 is presented below:

	Severance Liability
	(millions)
Balance at December 31, 2001	$16
Amounts paid	(5)
Revision of estimates	(7)
Balance at December 31, 2002	$ 4

2000 Restructuring Costs

In 2000, following the acquisition of CNG by Dominion, Dominion and its subsidiaries implemented a plan to restructure the operations of the combined companies. The restructuring plan included an involuntary severance program, a voluntary early retirement program (ERP) and a transition plan to implement operational changes to provide efficiencies, including the consolidation of post-merger operations and the integration of information technology systems. Through December 31, 2001, a total of 174 positions had been eliminated, and approximately $13 million of severance benefits had been paid. Severance payments were based on the individual's base salary and years-of-service at the time of termination. During 2000, approximately 400 Company employees elected to participate in the ERP, resulting in an expense approximating $51 million. Some of the ERP participants also received benefits under the involuntary severance package; benefits under the involuntary severance package were subject to reductions as a result of coordination with the additional retirement plan benefits provided by the ERP.

For the year ended December 31, 2000, the Company recorded $71 million for charges in connection with the 2000 restructuring plan, as follows:

- $14 million under an involuntary severance program (discussed above);
- $51 million under the ERP; and
- $6 million of other costs related to consolidation and integration of business operations and administrative functions.

Note 7. Income Taxes

Details of income tax expense were as follows:

	Year Ended December 31, 2002	2001	2000
		(millions)	
Current expense:			
Federal	$297	$198	$262
State	30	37	7
Total current	327	235	269
Deferred expense (benefit):			
Federal	90	50	32
State	25	18	(5)
Total deferred	115	68	27
Amortization of deferred investment tax credits, net	(17)	(17)	(17)
Total income tax expense	$425	$286	$279

The statutory U.S. federal income rate reconciles to the effective income tax rates as follows:

	Year Ended December 31, 2002	2001	2000
U.S statutory rate	35.0%	35.0%	35.0%
Increases (reductions) resulting from:			
Utility plant differences	(.2)	.7	.4
Amortization of investment tax credits	(1.1)	(1.8)	(1.4)
State income tax, net of federal tax benefit	3.0	4.9	.2
Other, net	(1.2)	.3	(.9)
Effective tax rate	35.5%	39.1%	33.3%

The Company's effective income tax rate decreased in 2002 due to a net benefit related to permanent differences, a reduction in percentages of state income taxes to book income and a decrease in book depreciation of regulated assets. The Company's effective income tax rate increased in 2001 due to its utility operations in Virginia becoming subject to state income taxes in lieu of gross receipts taxes.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The

Company's net accumulated deferred income taxes consist of the following:

	At December 31, 2002	At December 31, 2001
	(millions)	
Deferred income tax assets:		
Deferred investment tax credits	$ 36	$ 43
Other	49	37
Total deferred income tax assets	85	80
Deferred income tax liabilities		
Depreciation method and plant basis differences	1,561	1,479
Income taxes recoverable through future rates	15	19
Deferred state income tax	69	52
Other	58	30
Total deferred income tax liabilities	1,703	1,580
Total net deferred income tax liabilities[1]	$1,618	$1,500

[1] For 2002 and 2001, amounts include $49 million and $37 million, respectively, of current deferred tax assets reported in other current assets

Note 8. Nuclear Operations

The Company has four licensed nuclear reactors at its Surry and North Anna plants in Virginia that serve customers of its regulated electric utility operations. Decommissioning represents the decontamination and removal of radioactive contaminants from a nuclear power plant, once operations have ceased, in accordance with standards established by the NRC. Through June 2007, amounts are being collected from Virginia jurisdictional ratepayers and placed in external trusts and invested to fund the expected costs of decommissioning the Surry and North Anna units.

Accounting for Decommissioning

In accordance with the accounting policy recognized by regulatory authorities having jurisdiction over its electric utility operations, the Company recognizes an expense for the future cost of decommissioning in amounts equal to amounts collected from ratepayers and earnings on trust investments dedicated to funding the decommissioning of the Company's nuclear plants. On the Consolidated Balance Sheets, the external trusts are reported at fair value with the accumulated provision for decommissioning included in accumulated depreciation. Net realized and unrealized earnings on the trust investments, as well as an offsetting expense to increase the accumulated provision for decommissioning, are recorded as a component of other income(loss), as permitted by regulatory authorities. See Note 4 for a discussion of the impact of adopting SFAS No. 143 on the Company's accounting for decommissioning.

The balance of investments held in external trusts for decommissioning, as well as the accumulated provision for decommissioning, at December 31, 2002 and 2001, was $838 million and $858 million, respectively.

The Company collected $36 million from ratepayers in each of the years ended 2002, 2001 and 2000, respectively and expensed like amounts as a component of depreciation. The Company recognized net realized gains and interest income of $11 million, $32 million and $20 million for 2002, 2001, and 2000. The Company recognized net unrealized losses of $67 million, $61 million and $23 million, for 2002, 2001, 2000, respectively. The Company recognized offsetting increases or decreases to its provision for decommissioning in amounts equal to net realized and unrealized gains or losses for each period.

Expected Costs for Decommissioning

The total estimated current cost to decommission the Company's four nuclear units is $1.5 billion based on a site-specific study that was completed in 2002. A new cost estimate will be completed in 2006. The cost estimate assumes that the method of completing decommissioning activities is prompt dismantlement. Under current operating licenses, decommissioning would begin in 2012 as detailed in the table below. However, the Company filed a request with the NRC for a 20-year life extension for the Surry and North Anna units in 2001. The Company expects to decommission the units during the period 2032 to 2045.

	Surry Unit 1	Surry Unit 2	North Anna Unit 1	North Anna Unit 2	Total All Units
	(millions)				
NRC license expiration year	2012	2013	2018	2020	
Current cost estimate (2002 dollars)	$ 375	$ 368	$ 391	$ 363	$1,497
Funds in external trusts at December 31, 2002	235	230	192	181	838
2002 contributions to external trusts	11	11	7	7	36

The NRC requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of nuclear facilities. The Company's 2002 NRC minimum financial assurance amount, aggregated for the four nuclear units, was $1.1 billion and has been satisfied by a combination of surety bonds and the funds being collected and deposited in the external trusts. Beginning in March 2003, the Company expects to replace the surety bonds currently being utilized with a guarantee issued by Dominion.

Insurance

The Price-Anderson Act limits the public liability of a nuclear power plant owner to $9.5 billion for a single nuclear incident. The Price Anderson Act Amendment of 1988 allows for an inflationary provision adjustment every five years. The Company has purchased $200 million of coverage from commercial insurance pools with the remainder provided through a mandatory industry risk-sharing program. In the event of a nuclear incident at any licensed nuclear reactor in the United States, the Company could be assessed up to $88 million for each of its four licensed reactors, not to exceed $10 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed.

The Price-Anderson Act was first enacted in 1957 and has been renewed three times—in 1967, 1975 and 1988. Price-Anderson expired in August 2002, and Congress is currently holding hearings to reauthorize the legislation. The expiration of Price-Anderson has no impact on existing nuclear license holders.

The Company's current level of property insurance coverage ($2.55 billion for North Anna and $2.55 billion for Surry) exceeds the NRC's minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site and includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first to return the reactor to and maintain it in a safe and stable condition and second to decontaminate the reactor and station site in accordance with a plan approved by the NRC. The Company's nuclear property insurance is provided by the Nuclear Electric Insurance Limited (NEIL), a mutual insurance company, and is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance company. The maximum assessment for the current policy period is $43 million. Based on the severity of the incident, the board of directors of the Company's nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. The Company has the financial responsibility for any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination.

The Company also purchases insurance from NEIL to cover the cost of replacement power during the prolonged outage of a nuclear unit due to direct physical damage of the unit. Under this program, the Company is subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. The current policy period's maximum assessment is $19 million.

The North Anna Power Station is jointly owned as discussed in Note 13. The co-owner is responsible for its share of the nuclear decommissioning obligation and insurance premiums on applicable units, including any retrospective premium assessments and any losses not covered by insurance.

Note 9. Derivative Instruments, Hedge Accounting and Energy Trading Activities

Adoption of SFAS No. 133

The Company adopted SFAS No. 133 on January 1, 2001 and recorded an after-tax charge to accumulated other comprehensive income (AOCI) of $14 million, net of taxes of $9 million.

Risk Management Policy

The Company uses derivative instruments to manage the commodity, currency exchange and financial market risks of its business operations. The Company manages the price risk associated with purchases of natural gas and oil by utilizing derivative instruments including futures and swaps. The Company manages its foreign exchange risk associated with anticipated future purchases denominated in foreign currencies by utilizing currency forward contracts. The Company manages its interest rate risk exposure, in part, by entering into interest rate swap transactions.

As part of its strategy to market energy and to manage related risks, the Company manages a portfolio of commodity-based derivative instruments held for trading purposes. These contracts are sensitive to changes in the prices of energy commodities, primarily natural gas and electricity. The Company uses established policies and procedures to manage the risks associated with these price fluctuations and uses various derivative instruments, such as futures, swaps and options, to reduce risk by creating offsetting market positions. The Company has operating procedures in place that are administered by experienced management to help ensure that proper internal controls are maintained regarding the use of derivative instruments. In addition, Dominion has established an independent function to monitor compliance with the risk management policies of all subsidiaries.

The Company designates a substantial portion of derivative instruments held for purposes other than trading as fair value or cash flow hedges for accounting purposes. A significant portion of the Company's hedge strategies represents cash flow hedges of the variable price risk associated with purchases of natural gas, oil and other commodities. The Company also uses cash flow hedge strategies to hedge the variability in foreign exchange rates and variable interest rates on long-term debt using derivative instruments discussed in the preceding paragraphs. The Company also has designated interest rate swaps as fair value hedges to manage its exposure to fixed interest rates on certain long-term debt. Certain of the Company's non-trading derivative instruments are not designated as hedges for accounting purposes. However, management believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices and interest rates.

Accounting Policy

Under SFAS No. 133, derivatives are recognized on the Consolidated Balance Sheets at fair value, unless an exception is available under the standard. Certain qualifying derivative contracts have been designated as normal purchases or normal sales contracts. These contracts are not reported at fair value, as otherwise required by SFAS No. 133.

Commodity contracts representing unrealized gain positions are reported as derivative and energy trading assets; commodity contracts representing unrealized losses are reported as derivative and energy trading liabilities. In addition, purchased options and options sold are reported as derivative and energy trading assets and derivative and energy trading liabilities, respectively, at estimated market value until exercise or expiration.

For all derivatives designated as hedges, the Company formally documents the relationship between the hedging instrument and the hedged item, as well as the risk management objective and strategy for using the hedging instrument. The Company assesses whether the hedge relationship between the derivative and the hedged item is highly effective in offsetting changes in fair value or cash flows both at the inception of the hedge and on an ongoing basis. Any change in fair value of the derivative that is not effective in offsetting changes in the fair value of the hedged item is recognized currently in earnings. The Company discontinues hedge accounting prospectively for derivatives that have ceased to be highly effective hedges.

For fair value hedge transactions in which the Company is hedging changes in the fair value of an asset, liability or firm commitment, changes in the fair value of the derivative will generally be offset in the Consolidated Statements of Income by changes in the hedged item's fair value. For cash flow hedge transactions in which the Company is hedging the variability of cash flows related to a variable-priced asset, liability, commitment or forecasted transaction, changes in the fair value of the derivative are reported in AOCI.

Derivative gains and losses reported in AOCI are reclassified to earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portions of the change in fair value of derivatives and the change in fair value of derivatives not designated as hedges for accounting purposes are recognized in current period earnings. For foreign currency forward contracts designated as cash flow hedges, hedge effectiveness is measured based on changes in the fair value of the contract attributable to changes in the forward exchange rate. For options designated either as fair value or cash flow hedges, changes in time value are excluded from the measurement of hedge effectiveness and are therefore recorded in earnings.

Gains and losses on derivatives designated as hedges, when recognized, are included in operating revenue, operating expenses or interest and related charges in the Consolidated Statements of Income. Specific line item classification is determined based on the nature of the risk underlying individual hedge strategies. Changes in the fair value of derivatives not designated as hedges and the portion of hedging derivatives excluded from the measurement of effectiveness are included in other operations and maintenance expense in the Consolidated Statements of Income. Cash flows resulting from the settlement of derivatives used as hedging instruments are included in net cash flows from operating activities.

Derivative and Hedge Accounting Results

The Company recognized no hedge ineffectiveness during 2002. The Company experienced less than $1 million of ineffectiveness related to its hedges during 2001. The following table presents selected information related to cash flow hedges included in AOCI in the Consolidated Balance Sheet at December 31, 2002:

	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Earnings during the Next 12 Months	Maximum Term
	(dollar amount in millions)		
Interest Rate	$ (3)	$(2)	49 months
Foreign Currency	11	3	59 months
Total	$ 8	$ 1	

The actual amounts that will be reclassified to earnings in 2003 will vary from the expected amounts presented above as a result of changes in market prices, interest rates and foreign exchange rates. The effect of amounts being reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated purchases) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies.

Energy Trading Activities

The Company's non-derivative energy contracts initiated before October 25, 2002 and derivative instruments held for energy trading purposes are reported at fair value, with corresponding changes in value recognized immediately in earnings. See Note 4 for discussion of recent changes impacting the fair value accounting for energy trading contracts. Net gains and losses associated with the Company's commodity trading purchases and sales are presented net as other revenue. See Note 5. Cash flows resulting from the settlement of energy trading contracts are included in net cash flows from operating activities. The composition of operating revenue from commodity trading activities for the years 2002, 2001 and 2000 follows:

	Gains	Losses	Total
		(millions)	
2002			
Contract settlements	$10,616	$(10,640)	$ (24)
Unrealized gains and losses	1,496	(1,474)	22
Operating revenue	$12,112	$(12,114)	$ (2)
2001			
Contract settlements	$ 5,520	$ (5,508)	$ 12
Unrealized gains and losses	1,502	(1,361)	141
Operating revenue	$ 7,022	$ (6,869)	$153
2000			
Contract settlements	$ 2,773	$ (2,692)	$ 81
Unrealized gains and losses	1,236	(1,211)	25
Operating revenue	$ 4,009	$ (3,903)	$106

Note 10. Regulatory Assets and Liabilities

The Company accounts for its regulated operations in accordance with SFAS No. 71. Regulatory assets represent probable future revenue associated with certain costs that will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process.

In 1999, Virginia enacted the Virginia Electric Utility Restructuring Act (the Virginia Restructuring Act) that established a detailed plan to restructure Virginia's electric utility industry. Under the Virginia Restructuring Act, the generation portion of the Company's Virginia jurisdictional operations is no longer subject to cost-based regulation, effective January 1, 2002. The legislation's deregulation of generation was an event that required the discontinuance of SFAS No. 71 for the Company's generation operations in 1999.

The Company's regulatory assets and liabilities included the following:

	At December 31, 2002	2001
	(millions)	
Income taxes recoverable through future rates	$ 47	$ 49
Cost of decommissioning DOE uranium enrichment facilities	34	42
Deferred fuel	133	119
Other	25	21
Total	$239	$231

The incurred costs underlying regulatory assets may represent past expenditures by the Company's rate regulated operations or may represent the recognition of liabilities that ultimately will be settled at some time in the future. At December 31, 2002, approximately $24 million of the Company's regulatory assets represented past expenditures on which it does not earn a return. These expenditures consist primarily of deferred fuel costs for certain jurisdictions that are recovered within two years.

Income taxes recoverable through future rates resulted from the recognition of additional deferred income taxes, not previously recorded because of past ratemaking practices.

The cost of decommissioning the Department of Energy's (DOE) uranium enrichment facilities represents the Company's required contributions to a fund for decommissioning and decontaminating the DOE's uranium enrichment facilities. The Company began making contributions in 1992 which are expected to continue over a 15-year period with escalation for inflation. These costs are currently being recovered in fuel rates.

Deferred fuel accounting provides that the difference between 1) reasonably incurred actual cost of fuels used in electric generation and energy purchases and 2) the recovery for such costs included in current rates is deferred and matched against future revenue.

Note 11. Goodwill and Intangible Assets

In 2001, FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets* which prohibits the amortization of goodwill and intangible assets with indefinite useful lives. SFAS No. 142 also requires that these assets be reviewed for impairment at least annually. Intangible assets with finite lives will continue to be amortized over their estimated useful lives and will be reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable.

The Company adopted SFAS No. 142 on January 1, 2002. The Company does not have any goodwill; thus the provisions of SFAS No. 142 requiring the discontinuance of goodwill amortization did not have an impact on the Company's results of operations in 2002.

All of the Company's intangible assets are subject to amortization. Amortization expense for intangible assets was $24 million, $19 million and $16 million for 2002, 2001 and 2000, respectively. There were no material acquisitions of intangible assets during 2002. The components of intangible assets at December 31, 2002 were as follows:

	Gross Carrying Amount	Accumulated Amortization
	(millions)	
Software and software licenses	$208	$89
Other	16	6
Total	$224	$95

Amortization expense for intangible assets is estimated to be $28 million for 2003, $26 million for 2004, $21 million for 2005, $19 million for 2006 and $14 million for 2007.

Note 12. Property, Plant and Equipment

Property, plant and equipment, including nuclear fuel, consists of the following:

	At December 31, 2002	2001
	(millions)	
Generation	$ 8,497	$ 8,415
Transmission	1,598	1,565
Distribution	5,522	5,288
Nuclear fuel	740	757
General	647	655
	17,004	16,680
Other—including plant under construction	793	552
Total	$17,797	$17,232

Note 13. Jointly Owned Plants

The Company's proportionate share of jointly owned plants at December 31, 2002 follows:

	Bath County Pumped Storage Station	North Anna Power Station	Clover Power Station
	(millions, except percentages)		
Ownership interest	60.0%	88.4%	50.0%
Plant in service	$1,028	$1,861	$ 534
Accumulated depreciation	342	1,176	93
Nuclear fuel	—	341	—
Accumulated amortization of nuclear fuel	—	309	—
Plant under construction	4	82	12

The co-owners are obligated to pay their share of all future construction expenditures and operating costs of the jointly owned facilities in the same proportion as their respective ownership interest. The Company reports its share of operating costs in the appropriate operating expense (fuel, operations and maintenance, depreciation, taxes, etc.) in the Consolidated Statements of Income.

Note 14. Short-term Debt and Credit Agreements

Joint Credit Facilities

In May 2002, Dominion, CNG, and the Company entered into two joint credit facilities that allow aggregate borrowings of up to $2 billion. The facilities include a $1.25 billion 364-day revolving credit facility that terminates in May 2003 and a $750 million three-year revolving credit facility that terminates in May 2005. The 364-day facility includes an option to extend any borrowings for an additional period of one year to May 2004. These joint credit facilities are being used for working capital, as support for the combined commercial paper programs of Dominion, CNG and the Company, and other general corporate purposes. The three-year facility can also be used to support up to $200 million of letters of credit. The Company expects to renew the 364-day revolving credit facility prior to its maturity in May 2003.

At December 31, 2002, total outstanding commercial paper supported by the joint credit facilities was $1.2 billion, of which the Company's borrowings were $443 million, with a weighted average interest rate of 1.67 percent. At December 31, 2001, total outstanding commercial paper supported by previous credit agreements was $1.9 billion, of which the Company's borrowings were $436 million, with a weighted average interest rate of 1.96 percent.

At December 31, 2002, total outstanding letters of credit supported by the three-year facility were $106 million, which were issued for Dominion and CNG on behalf of subsidiaries. There were no outstanding letters of credit at December 31, 2001.

Note 15. Long-term Debt

Long- term debt consists of the following:

	2002 Weighted Average Coupon[2]	At December 31, 2002	2001
		(millions)	
First and Refunding Mortgage Bonds:			
6.0% to 8.625%, due 2002 to 2025[1]	7.56%	$1,666	$2,121
Senior and Medium-Term Notes:			
Variable rates, due 2002 to 2003[2]	2.37%	120	340
5.375% to 9.6%, due 2002 to 2038	5.95%	1,785	1,195
Tax-Exempt Financings[3]:			
Variable rates, due 2008 to 2027[2]	1.60%	197	197
4.95% to 5.875%, due 2007 to 2017[4]	5.49%	292	292
3.15% to 5.45%, due 2022 to 2031	3.67%	110	110
		4,170	4,255
Fair value hedge valuation[5]		7	4
Amount due within one year		(360)	(535)
Unamortized discount and premium, net		(23)	(20)
Total long-term debt		$3,794	$3,704

(1) Substantially all of the Company's property is subject to the lien of the mortgage securing its First and Refunding Mortgage Bonds (Mortgage Bonds). In 2002, the Company redeemed its $200 million, 6.75 percent 1997-A Mortgage Bonds due February 1, 2007. The Company completed the redemption with part of the proceeds from the issuance of $650 million, 5.375 percent Senior Notes due February 1, 2007 (Senior Notes). The redemption included a direct exchange of Senior Notes for $117 million of Mortgage Bonds. The Company used the remaining proceeds of Senior Notes to redeem the remaining $83 million of Mortgage Bonds and for general corporate purposes, including the repayment of other debt.

(2) Represents weighted-average coupon rates for debt outstanding as of December 31, 2002.

(3) Certain pollution control equipment at the Company's generating facilities has been pledged or conveyed to secure these financings.

(4) In 2002, the Company converted $292 million of its variable rate pollution control bonds to fixed rates, ranging from 4.95 percent to 5.875 percent. Other terms of the bonds remain the same.

(5) Represents changes in fair value of certain fixed rate long-term debt associated with fair value hedging relationships, as described in Note 22.

The scheduled principal payments of long-term debt at December 31, 2002 were as follows (in millions):

2003	2004	2005	2006	2007	Thereafter	Total
$360	$325	$—	$600	$880	$2,005	$4,170

The Company's short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2002, there were no events of default under the Company's covenants.

Note 16. Company Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust

In 2002, Virginia Power Capital Trust II (Trust), a trust subsidiary of the Company, sold 16 million 7.375 percent trust preferred securities for $400 million, representing preferred beneficial interests and 97 percent beneficial ownership in the assets held by the Trust. In exchange for the $400 million realized from the sale of the trust preferred securities and $12 million of common securities that represent the remaining 3 percent beneficial ownership interest in the assets held by the Trust, the Company issued $412 million of its 2002 7.375 percent Junior Subordinated Notes (Junior Subordinated Notes) due July 30, 2042. The Junior Subordinated Notes constitute 100 percent of the Trust's assets. The Trust must redeem the trust preferred securities when the Junior Subordinated Notes are repaid or if redeemed prior to maturity.

In 2002, the Company redeemed $139 million of junior subordinated notes held by Virginia Power Capital Trust I. The Trust redeemed all outstanding trust preferred securities for $135 million and redeemed $4 million of its common securities held by the Company.

Distribution payments on the trust preferred securities are guaranteed by the Company, but only to the extent that the trusts have funds legally and immediately available to make distributions. The trust's ability to pay amounts when they are due on the trust preferred securities is solely dependent upon the Company's payment of amounts when they are due on the junior subordinated notes. If the payment on the junior subordinated notes is deferred, the Company may not make distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also during the deferral period, it may not make any payments or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the junior subordinated notes.

Note 17. Preferred Stock

The Company is authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference. Upon involuntary liquidation, dissolution or winding-up of the Company, each share is entitled to receive $100 per share plus accrued dividends. Dividends are cumulative.

Holders of the outstanding preferred stock of the Company are not entitled to voting rights except under certain provisions of the amended and restated articles of incorporation and related provisions of Virginia law restricting corporate action, or upon default in dividends, or in special statutory proceedings and as required by Virginia law (such as mergers, consolidations, sales of assets, dissolution and changes in voting rights or priorities of preferred stock.)

In 2002, the Company purchased and redeemed, at par, all shares of its variable rate preferred stock October 1988 Series, June 1989 Series, September 1992A Series and September 1992B Series for $250 million, at the redemption price of $100 per share. The dividend rates for these series were variable and set every 49 days via an auction process. The combined weighted average rates for all series outstanding during 2002, 2001 and 2000, including fees for broker/dealer agreements, were 4.00 percent, 4.32 percent and 5.71 percent, respectively.

In 2002, the Company issued 1,250 units consisting of 1,000 shares per unit of cumulative preferred stock, for $125 million. The preferred stock has a dividend rate of 5.50 percent until the end of the initial dividend period on December 20, 2007. The dividend rate for subsequent periods will be determined according to periodic auctions. The preferred stock has a liquidation preference of $100 per share plus accumulated and unpaid dividends. Except during the initial dividend period, and any non-call period, this preferred stock will be redeemable, in whole or in part, on any dividend payment date at the option of the Company. The Company may also redeem this preferred stock, in whole but not in part, if certain changes are made to federal tax law which reduce the dividends received percentage.

Presented below are the series of preferred stock not subject to mandatory redemption that were outstanding as of December 31, 2002:

Dividend	Issued and Outstanding Shares[1]	Entitled Per Share Upon Liquidation
$5.00	107	$112.50
4.04	13	102.27
4.20	15	102.50
4.12	32	103.73
4.80	73	101.00
7.05	500	105.00[2]
6.98	600	105.00[3]
Flex MMP 12/02, Series A	1,250	100.00
Total	2,590	

(1) Shares are presented in thousands.
(2) Through 7/31/03; $103.53 commencing 8/1/03; amounts decline in steps thereafter to $100.00.
(3) Through 8/31/03; $103.49 commencing 9/1/03; amounts decline in steps thereafter to $100.00.

Note 18. Common Stock

In exchange for a $150 million reduction in amounts payable to Dominion, the Company issued common stock to Dominion in 2002.

Note 19. Accumulated Other Comprehensive Income

As of December 31, 2002 and 2001, accumulated other comprehensive income was $8 million and $(4) million, respectively, representing net unrealized gains (losses) on derivative instruments.

Note 20. Employee Benefit Plans

The Company participates in a defined benefit pension plan sponsored by Dominion. Benefits payable under the plan are based primarily on years of service, age and the employee's compensation. As a participating employer, the Company is subject to Dominion's funding policy, which is to contribute annually an amount that is in accordance with the provisions of the Employment Retirement Income Security Act of 1974. The Company's net periodic pension cost was $7 million, $7 million and $50 million in 2002, 2001 and 2000, respectively. The 2000 net periodic pension cost included $38 million for the effect of the ERP on the Company's pension plan. See Note 6 for more information on the ERP. The Company's contributions to the pension plan were $37 million, $7 million and $12 million in 2002, 2001 and 2000, respectively.

The Company participates in plans which provide certain retiree health care and life insurance benefits to multiple Dominion subsidiaries. Annual premiums are based on several factors such as age, retirement date and years of service. The Company's net periodic benefit cost was $34 million, $35 million and $42 million in 2002, 2001 and 2000, respectively.

Certain regulatory authorities have held that amounts recovered in rates for other postretirement benefits in excess of benefits actually paid during the year must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, the Company funds postretirement benefit costs through Voluntary Employees' Beneficiary Associations. The Company's contributions to health care and life insurance plans were $17 million, $10 million, and $3 million in 2002, 2001 and 2000, respectively.

The Company also participates in employee savings plans which cover substantially all employees. Employer matching contributions totaled $10 million, $10 million and $12 million in 2002, 2001 and 2000, respectively.

See Note 3 for the discussion of the accounting change for pension costs in 2000.

Note 21. Commitments and Contingencies

As the result of issues generated in the ordinary course of business, the Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies, some of which involve substantial amounts of money. Management believes that the final disposition of these proceedings will not have a material adverse effect on the Company's financial position, liquidity or results of operations.

Capital Expenditures

The Company has made substantial commitments in connection with its capital expenditures program. Those expenditures are estimated to total approximately $900 million, $665 million and $625 million for 2003, 2004 and 2005 respectively. Purchases of nuclear fuel are included in *Fuel Purchase Commitments* below. The Company expects that these expenditures will be met through a combination of sales of securities and short-term borrowings to the extent not funded by cash flow from operations.

Power Purchase Contracts

The Company has entered into contracts for long-term purchases of capacity and energy from other utilities, qualifying facilities and independent power producers. As of December 31, 2002, the Company has 42 non-utility purchase contracts with a combined dependable summer capacity of 3,758 megawatts.

The table below reflects the Company's minimum commitments as of December 31, 2002 under these contracts.

Year	Commitment Capacity	Commitment Other
	(millions)	
2003	$ 643	$ 44
2004	635	29
2005	629	22
2006	614	18
2007	589	11
Later years	5,259	113
Total	$8,369	$237
Present value of the total	$4,386	$140

Capacity purchases under these contracts totaled $691 million, $680 million and $740 million for 2002, 2001 and 2000, respectively.

In 2001, the Company completed the purchase of three generating facilities and the termination of seven contracts which provided electricity to the Company under long-term power purchase agreements with non-utility generators. The Company recorded an after-tax charge of $136 million in connection with the purchase and termination of the long-term power purchase agreements. Cash payments related to the purchase of the three generating facilities totaled $207 million. The allocation of the purchase price was assigned to the assets and liabilities acquired based upon estimated fair values as of the date of acquisition. Substantially all of the value was attributed to the power purchase agreements which were terminated and resulted in a charge included in operations and maintenance expense.

Fuel Purchase Commitments

The Company enters into long-term purchase commitments for fuel used in electric generation. Estimated fuel purchase commitments for the next five years are as follows: 2003—$439 million; 2004—$237 million; 2005—$174 million; 2006—$142 million; and 2007—$70 million. The Company recovers the costs of these purchases through regulated rates.

Lease Commitments

The Company leases various facilities, vehicles and equipment under both operating and capital leases. Future minimum lease payments under the Company's operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2002 are as follows: 2003—$39 million; 2004—$28 million; 2005—$20 million; 2006—$12 million; 2007—$10 million; and years after 2007—$34 million.

Under the terms of lease agreements, the Company has guaranteed that residual values of covered vehicles will be at least $44 million at the time such agreements expire or are terminated.

Rental expense included in operations and maintenance expense totaled $30 million, $25 million, and $24 million for 2002, 2001, and 2000, respectively.

In addition, the Company has entered into agreements with another Dominion subsidiary in order to develop, construct, finance and lease a new power generation facility at the Company's Possum Point station in Prince William County, Virginia. The project is scheduled for completion in 2003 at an estimated cost of $370 million. Upon completion, the Company will operate the new generating facility under an operating lease with estimated annual lease payments of $20 million.

Energy Trading

Subsidiaries of the Company enter into purchases and sales of commodity-based contracts in the energy-related markets, including natural gas, electricity, coal and oil. These agreements may cover current and future periods. The volume of these transactions varies from day to day, based on market conditions. See Note 9 for a discussion of the Company's energy trading activities and risk management policies.

Environmental Matters

The Company is subject to costs resulting from a steadily increasing number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

Historically, the Company recovered such costs arising from regulated electric operations through utility rates. However, to the extent environmental costs are incurred in connection with operations regulated by the Virginia State Corporation Commission, during the period ending June 30, 2007, in excess of the level currently included in Virginia jurisdictional rates, the Company's results of operations will decrease. After that date, the Company may seek recovery from customers through utility rates of only those environmental costs related to transmission and distribution operations.

Superfund Sites

From time to time, the Company may be identified as a potentially responsible party to a Superfund site. The Environmental Protection Agency (EPA) (or a state) can either (a) allow such a party to conduct and pay for a remedial investigation, feasibility study and remedial action or (b) conduct the remedial investigation and action and then seek reimbursement from the parties. Each party can be held jointly, severally and strictly liable for all costs. These parties can also bring contribution actions against each other and seek reimbursement from their insurance companies. As a result, the Company may be responsible for the costs of remedial investigation and actions under the Superfund Act or other laws or regulations regarding the remediation of waste. The Company does not believe that any currently identified sites will result in significant liabilities.

In 1987, the EPA identified the Company and a number of other entities as Potentially Responsible Parties (PRPs) at two Superfund sites located in Kentucky and Pennsylvania. Current cost studies estimate total remediation costs for the sites to range from $98 million to $152 million. The Company's proportionate share of the total cost is expected to be in the range of $2 million to $3 million, based on allocation formulas and the volume of waste shipped to the sites. The majority of remediation activities at the Kentucky site are complete and remediation design is ongoing for the Pennsylvania site. The Company has accrued a reserve of $2 million to meet its obligations at these two sites. Based on a financial assessment of the PRPs involved at these sites, the Company has determined that it is probable that the PRPs will fully pay their share of the costs. The Company generally seeks to recover its costs associated with environmental remediation from third party insurers. At December 31, 2002, any pending or possible claims were not recognized as an asset or offset against such obligations.

Other EPA Matters

During 2000, the Company received a Notice of Violation from the EPA, alleging that the Company failed to obtain New Source Review permits under the Clean Air Act prior to undertaking specified construction projects at the Mt. Storm Power Station in West Virginia. The Attorney General of New York filed a suit against the Company alleging similar violations of the Clean Air Act at the Mt. Storm Power Station. The Company also received notices from the Attorneys General of Connecticut and New Jersey of their intentions to file suit for similar violations. In December 2002, the Attorney General of Connecticut filed a motion to intervene as a plaintiff in the action filed by the New York State Attorney General. This action has been stayed. Management believes that the Company has obtained the necessary permits for its generating facilities. The Company has reached an agreement in principle with the federal government and the state of New York to resolve this situation. The agreement in principle includes payment of a $5 million civil penalty, a commitment of $14 million for environmental projects in Virginia, West Virginia, Connecticut, New Jersey and New York and a 12-year, $1.2 billion capital investment program for environmental improvements at the Company's coal-fired generating stations in Virginia and West Virginia. The Company had already committed to a substantial portion of the $1.2 billion expenditures for sulfur dioxide and nitrogen oxide emissions controls. The negotiations over the terms of a binding settlement have expanded beyond the basic agreement in principle and are ongoing. As of December 31, 2002, the Company has recorded, on a discounted basis, $18 million for the civil penalty and environmental projects.

In 2002, the EPA issued a Section 114 request for information about whether projects undertaken at the Company's Chesterfield, Chesapeake, Yorktown, Possum Point and Bremo Bluff power stations were properly permitted under the Clean Air Act's New Source Review requirements, to which the Company responded in a timely manner.

Surety Bonds

At December 31, 2002, the Company had issued $66 million of surety bonds, of which $57 million is associated with the financial assurance requirements imposed by the NRC with respect to the decommissioning of the Company's nuclear units. See Note 8 for more information on nuclear operations. Under the terms of the surety bonds, the Company is obligated to indemnify the respective surety bond company for any amounts paid.

Indemnifications

As part of commercial contract negotiations in the normal course of business, the Company may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. The Company is unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate the Company have not yet occurred or, if any such event has occurred, the Company has not been notified of its occurrence. However, at December 31, 2002, management believes future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on its results of operations, cash flows or financial position.

Spent Nuclear Fuel

Under provisions of the Nuclear Waste Policy Act of 1982, the Company has entered into contracts with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent nuclear fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and in the Company's contract with the DOE. The Company will continue to safely manage its spent fuel until accepted by the DOE.

Retrospective Premium Assessments

Under several of the Company's nuclear insurance policies, the Company is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to these insurance companies. For additional information, see Note 8.

Stranded Costs

Under the Virginia Restructuring Act, the generation portion of the Company's Virginia jurisdictional operations is no longer subject to cost-based rate regulation, effective January 1, 2002. The Company's base rates (excluding fuel costs and certain other allowable adjustments) will remain capped until July 2007, unless terminated sooner or otherwise modified consistent with the Virginia Restructuring Act. Under the Act, the Company may request a termination of the capped rates at any time after January 1, 2004, and the Virginia Commission may grant the Company's request to terminate the capped rates, if it finds that a competitive generation services market exists in the Company's service area. The Company believes capped electric retail rates and, where applicable, wires charges provided under the Virginia Restructuring Act provide an opportunity to recover a portion of its potentially stranded costs, depending on market prices of electricity and other factors. Stranded costs are those costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market.

Even in the capped rate environment, the Company remains exposed to numerous risks, including, among others, exposure to potentially stranded costs, future environmental compliance requirements, changes in tax laws, inflation and increased capital costs. At December 31, 2002, the Company's exposure to potentially stranded costs included: long-term power purchase contracts that could ultimately be determined to be above market (see *Power Purchase Contracts* above); generating plants that could possibly become uneconomic in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits not yet recognized in the financial statements. See Notes 8 and 20.

Note 22. Fair Value of Financial Instruments

Substantially all of the Company's financial instruments are recorded at fair value, with the exception of the instruments described below. Fair value amounts have been determined using available market information and valuation methodologies considered appropriate by management.

The Company reports the following financial instruments based on historical cost rather than fair value. The financial instruments' carrying amounts and fair values as of December 31, 2002 and 2001 were as follows:

	2002		2001	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(millions)			
Long-term debt[1]	$4,154	$4,408	$4,239	$4,313
Preferred securities of subsidiary trust[2]	400	414	135	137

[1] Fair value is estimated using market prices, where available; otherwise, interest rates currently available for issuance of debt with similar terms and remaining maturities are used. The carrying amount of debt issues with short-term maturities and variable rates repriced at current market rates is a reasonable estimate of their fair value.

[2] Fair value is based on market quotations.

Note 23. Concentration of Credit Risk

Credit risk is the risk of financial loss to the Company if counterparties fail to perform their contractual obligations. The Company sells electricity and provides distribution and transmission services to a diverse group of customers, including residential, commercial and industrial customers as well as rural electric cooperatives and municipalities. In addition, the Company enters into contracts with various companies in the energy industry for purchases and sales of energy-related commodities, including natural gas and electricity in its energy trading, hedging and arbitrage activities. These transactions principally occur in the Northeast, Midwest and Mid-Atlantic regions of the United States. Management does not believe that this geographic concentration contributes significantly to the Company's overall exposure to credit risk. Credit risk associated with trade accounts receivable from energy consumers is limited due to the large number of customers.

Dominion and its subsidiaries, including the Company, maintain credit policies with respect to its counterparties that management believes minimize overall credit risk. Where appropriate, such policies include the evaluation of a prospective counterparty's financial condition, collateral requirements, and in the case of energy trading, hedging and arbitrage activities, the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. On behalf of the Company, Dominion also monitors the financial condition of existing counterparties on an ongoing basis. The Company maintains a provision for credit losses based upon factors surrounding the credit risk of its customers, historical trends and other information. Management believes, based on Dominion's credit policies and its December 31, 2002 provision for credit losses, that it is unlikely that a material adverse effect on its financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

The Company calculates its gross credit exposure for each counterparty as the unrealized fair value of derivative and energy trading contracts plus any outstanding receivables (net of payables, where netting agreements exist), prior to the application of collateral. In the calculation of net credit exposure, the Company's gross exposure is reduced by collateral made available by counterparties, including letters of credit and cash received by the Company and held as margin deposits. Presented below is a summary of the Company's gross and net credit exposure as of December 31, 2002. The amounts presented exclude accounts receivable for regulated electric retail distribution and regulated electric transmission services, amounts payable to affiliated companies and the Company's provision for credit losses.

	At December 31, 2002		
	Credit Exposure Before Credit Collateral	Credit Collateral	Net Credit Exposure
	(millions)		
Investment grade[1]	$304	$ 15	$289
Non-investment grade[2]	44	25	19
No external ratings:			
Internal rated—investment grade[3]	198	—	198
Internal rated—non-investment grade[4]	24	—	24
Total	$570	$ 40	$530

[1] This category includes counterparties with minimum credit ratings of Baa3 assigned by Moody's Investor Service (Moody's) and BBB- assigned by Standard & Poor's Ratings Group, a division of The McGraw-Hill Companies, Inc. (Standard & Poor's). The five largest counterparty exposures, combined, for this category represented approximately 19 percent of the total gross credit exposure.

[2] This category includes counterparties with credit ratings that are below investment grade. The five largest counterparty exposures, combined, for this category represented approximately 8 percent of the total gross credit exposure.

[3] This category includes counterparties that have not been rated by Moody's or Standard & Poor's but are considered investment grade based on the Company's evaluation of the counterparty's creditworthiness. The five largest counterparty exposures, combined, for this category represented approximately 29 percent of the total gross credit exposure.

[4] This category includes counterparties that have not been rated by Moody's or Standard & Poor's and are considered non-investment grade based on the Company's evaluation of the counterparty's creditworthiness. The five largest counterparty exposures, combined, for this category represented approximately 2 percent of the total gross credit exposure.

Note 24. Related Party Transactions

The Company, through an unregulated subsidiary, exchanges certain quantities of natural gas and other commodities at market prices with other Dominion affiliates in the ordinary course of business. The affiliated commodity transactions are presented below:

	Year Ended December 31,		
	2002	2001	2000
	(millions)		
Purchases of natural gas, gas transportation and storage services from affiliates	$162	$133	$65
Sales of natural gas to affiliates	279	229	33

Through the same unregulated subsidiary, the Company is involved in facilitating Dominion's enterprise risk management strategy. In connection with this strategy, the Company enters into certain commodity derivative contracts with other Dominion affiliates. These contracts, which are principally comprised of commodity swaps, are used by Dominion affiliates to manage commodity price risks associated with purchases and sales of natural gas. As part of Dominion's enterprise risk management strategy, the Company generally manages such risk exposures by entering into offsetting derivative instruments with non-affiliates. The Company reports both affiliated and non-affiliated derivative instruments at fair value, with related changes included in earnings. The Company's Consolidated Balance Sheets include derivative and energy trading assets of $60 million and $159 million with Dominion affiliates at December 31, 2002 and 2001, respectively, and derivative and energy trading liabilities of $81 million and $77 million with Dominion affiliates at December 31, 2002 and 2001, respectively.

The Company's income from operations includes the recognition of the following derivative gains and losses on affiliated transactions:

	Year Ended December 31,		
	2002	2001	2000
	(millions)		
Net realized (gains) losses on commodity derivative contracts	$(45)	$(2)	$21

Effective February 1, 2000, Dominion created a subsidiary service company, Dominion Services, which provides certain services to the Company. In connection with the formation of Dominion Services, certain of the Company's employees became employees of Dominion Services. In 2001, the Company transferred certain assets and liabilities to Dominion Services with a net book value of approximately $27 million; no gain or loss was recorded on the transfer. The Company provides certain services to affiliates, including charges for facilities and equipment usage. The cost of these services provided to the Company and the amount billed for services provided by the Company follow:

	Year Ended December 31,		
	2002	2001	2000
	(millions)		
Services provided by Dominion Services	$267	$313	$202
Services provided by the Company to other affiliates	29	23	15

The Company leases its principal office building from Dominion under an agreement approved by the Virginia Commission that expires in 2006. This agreement is accounted for as a capital lease. The capitalized cost of the property under that lease, net of accumulated amortization, was approximately $12 million and $14 million at December 31, 2002 and 2001, respectively. The rental payments for this lease were $3 million in each of the years ended December 31, 2002, 2001 and 2000.

During 2002, Dominion advanced funds to certain unregulated subsidiaries of the Company pursuant to a short-term demand note (Demand Note). At December 31, 2002, the net outstanding borrowings under the Demand Note totaled $100 million. Interest charges incurred by the Company in 2002 were not material.

For information about the Company's agreement with another Dominion subsidiary, Dominion Equipment II, Inc. to develop, construct, finance and lease a new power generation facility at its Possum Point station in Prince William County, Virginia, see Note 21.

In July 2000, the Company transferred all of its issued and outstanding common stock in VPS Communications, Inc. (VPS) to Dominion. Dominion renamed VPS to Dominion Telecom, Inc. (DTI). In 2001, Dominion contributed DTI to Dominion Fiber Ventures LLC (DFV), a telecommunications joint venture. DFV is the sole owner of DTI. The Company leases fiber optic capacity to DTI at rates subject to the approval of the Virginia Commission. Payments received by the Company in connection with Dominion Telecom's lease of fiber optic equipment, and related fiber optic support and maintenance services, during 2002, 2001 and the period August 1, 2000 through December 31, 2000 were not material.

In 2001, an unregulated division of the Company transferred certain energy management services contracts and related leases to another Dominion subsidiary for $14 million, representing the Company's net book value recorded on its books for these contracts.

In exchange for a $150 million reduction in amounts payable to Dominion, the Company issued common stock to Dominion. See Note 18.

The Company's accounts receivable and payable balances with affiliates are settled based on contractual terms on a monthly basis, depending on the nature of the underlying transactions.

An unregulated subsidiary of the Company, at its sole discretion, has provided approximately $31 million of cash collateral to third parties on behalf of several of its natural gas supply customers. For this and other financial support services, the unregulated subsidiary receives fees and has a security interest in the customers' assets. The arrangements terminate at various dates beginning in 2005 through 2007, subject to periodic renewal thereafter unless terminated by either party.

See Notes 2, 7 and 20 for discussion of the inclusion of the Company in Dominion's consolidated federal income tax return and the Company's participation in certain Dominion employee incentive and benefit plans.

Note 25. Dividend Restrictions

The 1935 Act and related regulations issued by the SEC impose restrictions on the transfer and receipt of funds by a registered holding company, like Dominion, from its subsidiaries, including the Company. The restrictions include a general prohibition against loans or advances being made by the subsidiaries to benefit the registered holding company. Under the 1935 Act, registered holding companies and their subsidiaries may pay dividends only from retained earnings, unless the SEC specifically authorizes payments from other capital accounts.

The Virginia Commission may prohibit any public service company from declaring or paying a dividend to an affiliate, if found not to be in the public interest. As of December 31, 2002, the Virginia Commission had not restricted the payment of dividends by the Company.

Certain agreements associated with the Company's joint credit facilities with Dominion and CNG contain restrictions on the ratio of debt to total capitalization. These limitations did not restrict the Company's ability to pay dividends to Dominion or to receive dividends from its subsidiaries at December 31, 2002.

See Note 16 for a description of potential restrictions on dividend payments by the Company in connection with the deferral of distribution payments on trust preferred securities.

Note 26. Operating Segments

The Company is organized primarily on the basis of products and services sold in the United States. The Company manages its operations based on two operating segments:

- **Energy** manages the Company's portfolio of generating facilities and power purchase contracts and its energy trading and marketing, hedging and arbitrage activities.
- **Delivery** manages the Company's electric distribution and transmission systems as well as the metering services and customer service. The segment continues to be subject to the requirements of SFAS No. 71.

Effective January 1, 2003, the Company's electric transmission operations will be managed by the Energy segment instead of the Delivery segment.

The majority of the Company's revenue is provided through bundled rate tariffs. Generally, such revenues are allocated between the two segments for management reporting based on prior cost-of-service studies.

In addition, the Company also reports Corporate and Other as a segment. Corporate and Other includes certain expenses which are not allocated to the Energy or Delivery segments, including:

1) corporate operations;
2) transactions or amounts not allocated to the operating segments for internal reporting purposes:
   - 2001 termination of power purchase contracts (see Note 21);
   - 2002, 2001 and 2000 restructuring costs (see Note 6); and
   - 2000 cumulative effect of a change in accounting principle (see Note 3).

The Company's management evaluates performance based on a measure of profit and loss that represents each segment's contribution to the Company's net income. Intersegment sales and transfers are based on underlying contractual arrangements and agreements and may result in intersegment profit or loss.

The following table presents segment information pertaining to the Company's operations:

Description	Energy	Delivery	Corporate and Other	Eliminations	Consolidated Total
			(millions)		
Year ended December 31, 2002					
Total operating revenue	$3,697	$1,263	$ 13	$ (1)	$ 4,972
Depreciation and amortization	208	253	34	—	495
Interest and related charges	146	151	—	(3)	294
Income tax expense	248	175	2	—	425
Net income	447	322	4	—	773
Total assets	9,969	5,194	—	—	15,163
Capital expenditures	416	332	—	—	748
Year ended December 31, 2001					
Total operating revenue	3,722	1,212	12	(2)	4,944
Depreciation and amortization	222	264	32	—	518
Interest and related charges	145	156	3	(4)	300
Income tax expense	246	142	(102)	—	286
Net income	380	230	(164)	—	446
Total assets	8,764	5,020	—	—	13,784
Capital expenditures	330	338	—	—	668
Year ended December 31, 2000					
Total operating revenue	3,577	1,210	6	(2)	4,791
Depreciation and amortization	269	251	38	—	558
Interest and related charges	148	145	7	(4)	296
Income tax expense	178	133	(32)	—	279
Net income	369	246	(36)	—	579
Capital expenditures	319	333	—	—	652

Note 27. Quarterly Financial Data (Unaudited)

A summary of the quarterly results of operations for the years 2002 and 2001 follows. Amounts reflect all adjustments, consisting of only normal recurring accruals, necessary in the opinion of management for a fair statement of the results for the interim periods. Results for interim periods may fluctuate as a result of weather conditions, changes in rates and other factors.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
			(millions)		
2002					
Operating revenue	$1,151	$1,221	$1,474	$1,126	$4,972
Income from operations	312	341	554	253	1,460
Net income	153	175	316	129	773
Balance available for common stock	149	170	311	127	757
2001					
Operating revenue	$1,222	$1,177	$1,444	$1,101	$4,944
Income from operations	109	297	495	98	999
Net income	25	134	266	21	446
Balance available for common stock	18	128	260	17	423

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

None.

Part III

Item 10. Directors and Executive Officers of the Registrant

(a) Information concerning directors of Virginia Electric and Power Company, each of whom is elected annually, is as follows:

Name and Age	Principal Occupation for Last Five Years and Directorships in Public Corporations	Year First Elected as Directors
Thos. E. Capps (67)	Chairman of the Board of Directors of Virginia Electric and Power Company from September 1997 to date; Chairman of the Board of Directors, President and Chief Executive Officer of Dominion from August 2000 to date; Chairman of the Board of Directors of Consolidated Natural Gas Company from September 1999 to date; Vice Chairman of the Board of Directors, President and Chief Executive Officer of Dominion from January 2000 to August 2000; Chairman of the Board of Directors, President and Chief Executive Officer of Dominion from September 1995 to January 2000.	1986
Thomas F. Farrell, II (48)	Executive Vice President of Dominion from March 1999 to date; President and Chief Executive Officer of Virginia Electric and Power Company from December 2002 to date; Executive Vice President of Consolidated Natural Gas Company from January 2000 to date; Director of Consolidated Natural Gas Company from January 2000 to date; Chief Executive Officer of Virginia Electric and Power Company from May 1999 to December 2000; Executive Vice President, General Counsel and Corporate Secretary of Virginia Electric and Power Company from July 1998 to April 1999; Executive Vice President and General Counsel of Virginia Electric and Power Company from April 1998 to June 1998; Executive Vice President of Virginia Electric and Power Company from September 1997 to April 1998; Senior Vice President—Corporate Affairs of Dominion from September 1997 to March 1999.	1999
Thomas N. Chewning (57)	Executive Vice President and Chief Financial Officer of Dominion from May 1999 to date; Executive Vice President and Chief Financial Officer of Consolidated Natural Gas Company from January 2000 to date; Director of Consolidated Natural Gas Company from December 2002 to date; Executive Vice President of Dominion prior to April 1999.	2002

(b) Information concerning the executive officers of Virginia Electric and Power Company, each of whom is elected annually is as follows:

Name and Age	Business Experience Past Five Years
Thomas F. Farrell, II (48)	President and Chief Executive Officer of Virginia Electric and Power Company from December 2002 to date; Executive Vice President of Dominion from March 1999 to date; Executive Vice President of Consolidated Natural Gas Company from January 2000 to date; Chief Executive Officer of Virginia Electric and Power Company from May 1999 to December 2000; Executive Vice President, General Counsel and Corporate Secretary of Virginia Electric and Power Company from July 1998 to April 1999; Executive Vice President and General Counsel of Virginia Electric and Power Company from April 1998 to June 1998; Executive Vice President of Virginia Electric and Power Company from September 1997 to April 1998; Senior Vice President—Corporate Affairs of Dominion from September 1997 to March 1999.
Jay L. Johnson (56)	President and Chief Executive Officer of Virginia Electric and Power Company from December 2002 to date; Executive Vice President of Dominion from December 2000 to date; Senior Vice President, Business Excellence, Dominion Energy, Inc. from September 2000 to December 2002; Chief of Naval Operations, U.S. Navy, and member of the Joint Chiefs of Staff from 1996 until July 2000.
Paul D. Koonce (43)	Chief Executive Officer—Transmission of Virginia Electric and Power Company from January 2003 to date; Senior Vice President—Portfolio Management of Virginia Electric and Power Company from January 2000 to December 2002; Senior Vice President—Commercial Operations of Consolidated Natural Gas Company from January 1999 to January 2000; Senior Vice President—Sonat Energy Services from August 1997 to January 1999.
Mark F. McGettrick (45)	President and Chief Executive Officer—Generation of Virginia Electric and Power Company from January 2003 to date; Senior Vice President and Chief Administrative Officer of Dominion from January 2002 to January 2003; Senior Vice President—Customer Service and Metering of Virginia Electric and Power Company from January 2000 to December 2001; Vice President—Customer Service and Metering of Virginia Electric and Power Company from January 1997 to January 2000.
Gary L. Sypolt (49)	President—Transmission of Virginia Electric and Power Company from January 2003 to date; Senior Vice President—Transmission of Dominion Transmission, Inc., formerly CNG Transmission Corporation, from September 1999 to January 2003.
M. Stuart Bolton (49)	Senior Vice President—Financial Management of Virginia Electric and Power Company from January 2000 to date; Vice President and Controller of Virginia Electric and Power Company from January 1999 to January 2000; Controller of Virginia Electric and Power Company, from January 1996 to January 1999.
David A. Christian (48)	Senior Vice President—Nuclear Operations and Chief Nuclear Officer from April 2000 to date; Vice President—Nuclear Operations from July 1998 to April 2000; Site Vice President—Surry from March 1998 to June 1998; Station Manager from September 1994 to March 1998.
G. Scott Hetzer (46)	Senior Vice President and Treasurer of Virginia Electric and Power Company and Consolidated Natural Gas Company from January 2000 to date; Senior Vice President and Treasurer of Dominion from May 1999 to date; Vice President and Treasurer of Dominion from October 1997 to May 1999.

Name and Age	Business Experience Past Five Years
E. Paul Hilton (59)	Senior Vice President of Virginia Electric and Power Company from January 2000 to date; Vice President of Virginia Electric and Power Company from May 1999 to January 2000; Vice President-Regulation of Virginia Electric and Power Company from September 1997 to April 1999.
Thomas A. Hyman, Jr. (51)	Senior Vice President—Gas Distribution and Customer Services of Virginia Electric and Power Company from January 2002 to date; Senior Vice President—Gas Distribution and Customer Services of Regulated Gas Distribution Companies of Consolidated Natural Gas Company from December 2001 to date; Senior Vice President—Gas Distribution of Regulated Gas Distribution Companies of Consolidated Natural Gas Company from October 2000 to December 2001; Senior Vice President—Electric Distribution of Virginia Electric and Power Company from January 2000 to October 2000; Vice President and General Manager—Distribution of Virginia Electric and Power Company from May 1999 to January 2000; Vice President—Distribution Operations and North Carolina Power of Virginia Electric and Power from June 1997 to April 1999.
William R. Matthews (55)	Senior Vice President— Nuclear Operations of Virginia Electric and Power Company from July 2002 to date; Vice President and Senior Nuclear Executive of Dominion Energy, Inc. from May 2001 to February 2002; Vice President-Nuclear Operations of Virginia Electric and Power Company from April 2000 to May 2001; Site Vice President—North Anna of Virginia Electric and Power Company from March 1998 to April 2000.
Margaret E. McDermid (54)	Senior Vice President—Information Technology and Chief Information Officer of Virginia Electric and Power Company from January 2001 to date; Vice President—Information Technology and Chief Information Officer of Virginia Electric and Power Company from October 1998 to January 2001; Manager—Information Systems and Client Services of Virginia Electric and Power Company from December 1991 to October 1998.
Edward J. Rivas (58)	Senior Vice President—Fossil & Hydro of Virginia Electric and Power Company from September 1999 to date; Vice President—Fossil & Hydro Operations of Virginia Electric and Power Company from February 1998 to August 1999.
Jimmy D. Staton (42)	Senior Vice President—Electric Distribution of Virginia Electric and Power Company from January 2003 to date; Senior Vice President—Electric Transmission and Electric Distribution of Virginia Electric and Power Company from December 2001 to December 2002; Senior Vice President—Electric Distribution of Virginia Electric and Power Company from October 2000 to December 2001; Senior Vice President—Gas Distribution and Regulatory of Virginia Electric and Power Company from January 2000 to October 2000; Senior Vice President—Commercial Operations of Consolidated Natural Gas Company from June 1999 to January 2000; Vice President—Commercial Operations of Consolidated Natural Gas Company from January 1999 to June 1999; Vice President and Treasurer of Dominion Transmission, Inc., formerly CNG Transmission Corporation from March 1997 to June 1999.
Steven A. Rogers (41)	Principal Accounting Officer of Virginia Electric and Power Company from June 2000 to date; Vice President, Controller and Principal Accounting Officer of Dominion and Consolidated Natural Gas Company and Vice President from June 2000 to date; Controller of Virginia Electric and Power Company from January 2000 to May 2000. Controller of Dominion Energy, Inc. from September 1998 to June 2000; Vice President and Controller of Optacor Financial Services Company from February 1997 through September 1998.

Any service listed for Dominion, Dominion Energy, Inc., Consolidated Natural Gas Company, Dominion Transmission, Inc., and Optacor Financial Services Company reflects services at a parent, subsidiary or affiliate.

There is no family relationship between any of the persons named in response to Item 10.

Section 16(a) Beneficial Ownership Reporting Compliance

Our directors and officers report their Virginia Power stock transactions, including initial reports of beneficial ownership on Form 3. Due to administrative oversight, the initial statements of ownership on Form 3 were filed late for the following officers: Messers. Hetzer; Rogers; Chewning; Staton; Sypolt; and Hyman. None of these officers/ directors owned any Virginia Power securities, nor have they acquired any since becoming a Section 16 reporting person. Furthermore, from time to time a Section 16 person may leave an executive officer or director position at the Company for service with an affiliate, returning back to an executive officer or director position at the Company after an absence. Under such circumstances, the Company may not re-file a statement of initial ownership if there have been no changes in such person's ownership of the Company's securities.

Item 11. Executive Compensation

The Summary Compensation Table below includes compensation paid by the Company for services rendered in 2002, 2001 and 2000 to the Chief Executive Officers, the four other most highly compensated executive officers and two retired officers (as of December 31, 2002) as determined under the SEC executive compensation disclosure rules.

Summary Compensation Table[1]

		Annual Compensation			Long Term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary[2]	Bonus	Other Annual Compensation[3]	Restricted Stock Awards[4]	Securities Underlying Options/SARs[5]	LTIP Payouts[6]	All Other Compensation[7]
Thomas F. Farrell, II	2002	$310,784	$274,428	$55,102	$ —	$ —	$ —	$ 73,893
Chief Executive Officer	2001	328,498	273,955	58,197	489,154	351,600	—	135,728
& President	2000	324,638	409,214	71,002	—	79,765	275,441	155,914
Jay L. Johnson	2002	128,404	120,922	18,903	—	—	—	21,697
Chief Executive Officer	2001	136,052	61,223	16,179	154,451	48,590	—	23,299
& President	2000	44,041	17,003	4,307	—	32,855	7,393	5,116
Jimmy D. Staton	2002	253,604	126,802	31,717	—	—	—	46,023
Senior Vice President—	2001	260,000	117,000	34,100	300,500	100,000	—	81,284
Elec Distr & Elec Trans	2000	63,225	30,222	2,216	—	11,250	—	6,959
E. Paul Hilton	2002	185,000	92,500	21,820	—	—	—	33,315
Senior Vice President	2001	185,000	236,422	21,820	317,800	100,000	—	33,315
	2000	151,967	91,426	21,820	—	43,082	67,794	30,474
Edward J. Rivas	2002	155,980	77,990	24,797	—	—	—	35,637
Senior Vice President	2001	162,360	72,331	25,765	239,318	73,800	—	61,885
Fossil & Hydro	2000	208,634	191,836	34,912	—	40,000	102,264	81,475
David A. Christian	2002	151,410	102,807	12,807	—	—	—	21,268
Senior Vice President	2001	285,900	183,977	24,675	397,571	190,600	—	64,343
Nuclear Operations &	2000	183,484	158,064	24,183	—	33,832	93,655	31,211
Chief Nuclear Officer								
Edgar M. Roach, Jr.	2002	330,797	292,100	64,510	—	—	—	78,652
President and Chief	2001	334,664	279,098	66,550	495,525	298,500	—	145,541
Executive Officer	2000	251,732	314,424	71,914	—	61,289	211,638	125,795
(retired)								
James P. O'Hanlon	2002	221,760	177,408	44,186	—	—	—	60,406
President and Chief	2001	234,400	175,800	46,807	363,253	205,100	—	109,148
Operating Officer	2000	268,570	305,690	56,667	—	64,926	221,045	127,595
(retired)								

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion Compensation for the individuals listed in the table reflects only that portion which is allocated to the Company

(2) **Salary**—Amounts shown may include vacation sold back to the Company.

(3) **Other Annual Compensation**—None of the named executives above received perquisites or other personal benefits in excess of $50,000 or 10% of their total cash compensation The amounts listed in this column are tax payments made on behalf of the executive

(4) **Restricted Stock Awards**—The number and value of each executive's aggregated restricted stock holdings at year-end, based on a December 31, 2002 closing price of $54.90 per share, were as follows

Officer	Number of Restricted Shares(*)	Value	Vesting Schedule
	(#)	($)	
Thomas F. Farrell, II	5,860	$321,714	3 years
Jay L. Johnson	2,256	123,854	3 years
Jimmy D. Staton	5,000	274,500	3 years
E. Paul Hilton	5,000	274,500	3 years
Edward J. Rivas	3,690	202,581	3 years
David A. Christian	6,354	348,835	3 years
Edgar M. Roach, Jr.	5,970	327,753	3 years
James P. O'Hanlon	4,883	268,077	3 years

Dividends are paid on restricted shares.

(5) **Securities Underlying Options**—Options granted in 2002 and 2001 were three-year options. Options granted in 2000 were granted and simultaneously exercised by the named executives to purchase shares under the Executive Stock Purchase and Loan Program.

(6) **LTIP Payouts**—Amounts in this column represent cash awards under the 1998-2000 Long-Term Incentive Plan.

(7) **All Other Compensation**—The amounts listed for 2002 are:

(1) Company matching contributions on Employee Savings Plan accounts for the named executives; and

(2) a quarterly interest rate subsidy paid under the Executive Stock Purchase and Loan Program.

Officer	Employee Savings Plan Match	Executive Stock Loan Program Interest Subsidy	Employee Savings Plan Match Above IRS Limits
Thomas F. Farrell, II	$2,827	$64,746	$6,320
Jay L. Johnson	2,301	17,845	1,551
Jimmy D. Staton	4,974	38,415	2,634
E. Paul Hilton	6,800	25,915	600
Edward J. Rivas	4,821	29,398	1,418
David A. Christian	3,432	15,212	2,624
Edgar M. Roach, Jr.	3,010	68,915	6,727
James P. O'Hanlon	2,827	52,478	5,101

Aggregated Option/SAR Exercises in Last Fiscal Year(1) And FY-End Option/SAR Values

	Shares Acquired on Exercise	Value Realized(2)	Number of Securities Underlying Unexercised Options/SARs At FY-End		Value of Unexercised In-the-Money Options/SARs At FY-End(3)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
	(#)	($)	(#)	(#)	($)	($)
Thomas F. Farrell, II	49,896	$1,257,745	199,584	332,640	$2,724,322	$ —
Jay L. Johnson	—	—	19,627	45,120	—	—
Jimmy D. Staton	4,877	99,313	19,508	97,540	171,865	—
E. Paul Hilton	14,816	403,104	59,266	100,000	815,513	—
Edward J. Rivas	11,604	292,511	46,416	70,899	536,275	—
David A. Christian	7,218	175,277	28,868	100,940	367,452	—
Edgar M. Roach, Jr.(4)	53,109	1,338,737	212,436	295,050	2,899,751	—
James P. O'Hanlon(4)	90,552	1,639,488	103,488	194,040	1,412,611	—

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. Options and shares acquired on exercise for individuals listed in the table reflect only that portion which is allocated to the Company.

(2) Spread between the market value at exercise minus the exercise price.

(3) Spread between the market value at year-end minus the exercise price. Year-end stock price was $54.90 per share.

(4) At December 31, 2002, Messrs. Roach and O'Hanlon were not serving as executive officers of the Company but are listed in this table according to SEC disclosure rules. Each retired from the Company on February 1, 2003.

Executive Compensation

The Company's executive compensation program is regularly reviewed by the Organization, Compensation and Nominating Committee of the Dominion Board (Dominion's Committee) and its recommendations are subsequently referred to the Company's Board of Directors. Dominion's Committee acts independently of management and works with an outside consultant to focus on the attraction, retention and motivation of management in a reasonable and cost-effective manner. It also endorses the use of performance-based compensation for its management team.

Annual Incentive

Under the annual incentive program, if goals are achieved or exceeded, the executive's total cash compensation for the year is targeted to be between the median and 75th percentile of total cash compensation for similar positions at companies in our executive labor market.

Under this program, "target awards" are established for each executive officer. These target awards are expressed as a percentage of the individual executive's base salary (for example, 40% x base salary). The target award is the amount of cash that will be paid at year-end if the executive achieves 100% of the goals established at the beginning of the year. A "threshold"—or minimum acceptable level of corporate financial performance—is established, and if this threshold is not met, no executive receives an annual incentive payment. Actual payments, if any, are based on a pre-established formula and may exceed 100% of the target award if performance expectations are exceeded. Annual bonuses paid to the named executives are detailed in the Summary Compensation Table.

Long-term Incentives

Currently, there is no plan to grant Dominion stock options to the Company's executives, but will look to other forms of equity compensation to comprise the long-term incentive component as it works toward rebalancing its executive compensation program. The Company believes that equity compensation remains the strongest form of long-term incentive and underscores commitment to the Company while rewarding performance.

Stock Ownership Guidelines

Stock ownership guidelines were established for the Company executive officers in 2000. These guidelines place an emphasis on stock ownership to align the interests of management and Dominion shareholders. While the enactment of the Sarbanes-Oxley Act has eliminated some of the tools the Company had provided to assist executives in meeting the guidelines, the Company continues to encourage executives to accumulate shares to meet the guidelines within five years.

Dominion Resources, Inc.
Stock Ownership Guidelines

Position	Share Ownership
CEO/COO-Operating Companies	35,000
Senior Vice President	20,000
Vice President	10,000

Retirement Plans

The table below shows the estimated annual straight life benefit that the Company would pay to an employee at normal retirement (age 65) under the benefit formula of the Pension Plan.

Estimated Annual Benefits Payable Upon Retirement

Final Average Earnings	Credited Years Of Service 15	20	25	30
$185,000	$ 50,376	$ 67,140	$ 83,904	$100,668
$200,000	54,900	73,188	91,464	109,752
$250,000	69,024	92,016	114,996	137,976
$300,000	83,928	111,912	139,884	167,880
$350,000	98,820	131,808	164,784	197,772
$400,000	113,712	151,704	189,684	227,664

Benefits under the Pension Plan are based on:

- highest average base salary over a five consecutive year period during the ten years preceding retirement;
- years of credited service;
- age at retirement; and
- the offset of Social Security benefits.

The Company provides a Special Retirement Account (SRA) feature to the Pension Plan. This account is credited with two-percent of an employee's base salary earned each year. Account balances are credited with earnings based on the 30-year Treasury rate and may be taken as a lump sum or an annuity at retirement. The above table includes the effect of SRA balances converted to an annual annuity.

In addition, certain officers, if they reach a specified age while still employed, will be credited with additional years of service. Each of the named executives in the Summary Compensation Table, except for Mr. Johnson and Mr. Staton, will have 30 years of credited service at age 60. Other retirement agreements and arrangements for the named executives are described below under Other Executive Agreements and Arrangements.

Benefit Restoration Plan

The Pension Plan pays a benefit that is calculated on average base salary over a five-year period. In some years our executives' base salaries were set below the competitive market median in order to more closely link annual pay to Company performance through the incentive programs. Under this Restoration Plan, we calculate a "market-based adjustment" to base salary in those years when base salary was below the market median. The difference between the benefit calculated on the market-based salary and the benefit provided by the Pension Plan is paid to the executive under the Restoration Plan.

In 2002, a market-based adjustment to executive base salaries was not necessary.

Also, the Internal Revenue Code imposes certain limits related to Pension Plan benefits. Any resulting reduction in an executive's Pension Plan benefit will be compensated for under the Restoration Plan.

Executive Supplemental Retirement Plan

The Supplemental Plan provides an annual retirement benefit equal to 25% of a participant's final cash compensation (base pay plus target annual incentive). To retire with full benefits under the Supplemental Plan, an executive must be 55 years old and have been employed by the Company for at least five years. Benefits under the plan are provided either as a lump sum cash payment at retirement or as a monthly annuity typically paid over 10 years. Certain executive officers receive this benefit for their lifetime. Based on 2002 cash compensation, the estimated annual benefit under this plan for executives named in the Summary Compensation Table are: Mr. Farrell—$144,837; Mr. Johnson—$68,018; Mr. Staton—$95,102; Mr. Hilton—$69,375; Mr. Rivas—$58,493; Mr. Christian—$64,349; Mr. Roach—$154,164; Mr. O'Hanlon—$99,792.

Other Executive Agreements and Arrangements

Companies that are in a rapidly changing industry such as ours require the expertise and loyalty of exceptional executives. Not only is the business itself competitive, but so is the demand for such executives. In order to secure the continued services and focus of key management executives, the Company has entered into certain agreements with them, including those named in the Summary Compensation Table.

Messrs. Farrell, Johnson, Hilton, Rivas and Christian each have enhanced retirement benefits as well as employment continuity agreements as described below under Special Arrangements.

Employment Agreements

Mr. Staton has an employment agreement with the Company's parent, Dominion, for a three-year period ending on August 1, 2003. During the term of the agreement, Mr. Staton will continue to receive a salary at least equal to his salary on the date of the agreement and will be eligible for bonuses and all employee benefits provided to senior management. The agreement also provides for retirement benefits and benefits in the event of death or disability. If Mr. Staton's employment is terminated without cause or if his salary, incentives or benefits are reduced or not paid, or he is demoted to a position that is not a senior management position, he will, subject to notice and remedy provisions: (1) receive a lump sum payment equal to the present value of salary and cash bonus for the balance of the contract period, (2) vest in his outstanding stock options and (3) receive continued benefit plan coverage through the end of the contract period. In addition, as of the effective date of Mr. Staton's employment agreement, a payment was made into an account created by him in the Dominion Resources, Inc. Executives' Deferred Compensation Plan. This payment was made in lieu of Mr. Staton's right to receive payment under his change in control agreement with CNG. If Mr. Staton's employment is terminated for any reason, he will receive payment of the deferred amount together with payment of his benefits under the Unfunded Supplemental Benefit Plan for Employees of Consolidated Natural Gas Company and its Participating Subsidiaries Who Are Not Represented by a Recognized Union. These amounts will be paid in lieu of severance benefits under any severance program maintained by Dominion (except for benefits specifically provided for under his employment continuity agreement as described below).

Special Arrangements

Executives named in the Summary Compensation Table have entered into employment continuity agreements, which provide benefits in the event of a change in control. Each agreement has a three-year term and is automatically extended for an additional year, unless cancelled by the Company.

The agreements provide for the continuation of salary and benefits for a maximum period of three years after either (1) a change in control, (2) termination without cause following a change in control, or (3) a reduction of responsibilities, salary and incentives following a change in control (if the executive gives 60 days notice). Payment of this benefit will be made in either a lump sum or installments over three years. In addition, the agreements indemnify the executives for potential penalties related to the Internal Revenue Code and fees associated with the enforcement of the agreements. If an executive is terminated for cause, the agreements are not effective.

For purposes of the continuity agreements described above, a change of control shall be deemed to have occurred if (i) any person or group becomes a beneficial owner of 20% or more of the combined voting power of Dominion voting stock or (ii) as a direct or indirect result of, or in connection with, a cash tender or exchange offer, a merger or other business combination, a sale of assets, or contested election, the Directors constituting the Dominion Board before any such transactions cease to represent a majority of Dominion or its successor's Board within two years after the last of such transactions.

Mr. Farrell also has a letter agreement with Dominion providing him with a lump sum payment of 12 months base salary upon retirement in consideration for his agreement not to compete with any activities of Dominion nor solicit any employees of Dominion during his employment and for a period of two years following termination of his employment. Mr. Christian has entered into a Supplemental Agreement with Dominion whereby he has also agreed not to compete with the activities of Dominion nor solicit any Dominion employees in consideration of his receipt of benefits under the Executive Supplemental Retirement Plan described above.

Messrs. Roach and O'Hanlon resigned their respective officer positions with the Company and its subsidiaries effective December 1, 2002, and retired effective February 1, 2003. In accordance with their retirement agreements, each received accelerated vesting and extended expiration dates on options held, as well as other enhanced retirement and miscellaneous benefits. They both signed a general release for any claims against the Company. Mr. Roach also received reimbursement for certain relocation expenses, a lump sum payment equal to 12 months salary in accordance with his employment agreements, and an additional lump sum severance payment. Mr. Roach will be restricted from competing with any activities of Dominion or soliciting any employees of Dominion for a period of two years following termination of his employment.

Executive Stock Purchase Programs

At the end of 1999, Dominion's Board approved target levels of stock ownership for executives. The Board also approved a Stock Purchase and Loan Program intended to encourage and facilitate executives' ownership of common stock through the availability of loans guaranteed by Dominion. Officers borrowed money from an independent bank to purchase stock for which they are personnally liable and which Dominion has guaranteed. Because of new restrictions on company loans or guarantees to executives under the Sarbanes-Oxley Act of 2002, Dominion has ceased its programs involving the company guaranty of a third party loan to executives for the purpose of acquiring company stock.

During 2001, the stock ownership guidelines for executives were reconfirmed and the Executive Stock Purchase Tool Kit was implemented. The Tool Kit consists of a variety of programs to encourage ownership of Dominion stock by executives who could not participate in the Executive Stock Purchase and Loan programs. Executives who participate in one or more of the Tool Kit programs to achieve their stock ownership target levels receive "bonus shares" for up to ten percent of the value of their investments in Dominion stock. The Tool Kit previously included the availability of loans guaranteed by Dominion, but this alternative has been omitted for the reasons discussed above.

As of December 31, 2002, Dominion officers have borrowed in aggregate $70.4 million under these programs, for which they are personally liable and which Dominion has guaranteed.

Compensation of Directors

All of the Directors, who are also officers of the Company, do not receive any compensation for services they provide as directors.

Item 12. Security Ownership Of Certain Beneficial Owners And Management

The table below sets forth as of February 21, 2003, except as noted, the number of shares of Dominion common stock owned by Directors and the executive officers named on the Summary Compensation Table.

	Beneficial Share Ownership				
Name	**Shares**	**Restricted Shares**	**Exercisable Stock Options**	**Total**	**Deferred Cash Compensation[1]**
Thos. E. Capps[2]	327,673	16,667	1,386,400	1,730,740	—
Thomas N. Chewning	109,814	8,333	510,000	628,147	165
Thomas F. Farrell, II[2]	143,353	10,000	560,000	713,353	—
Jay L. Johnson	21,445	5,000	76,833	103,278	59
Jimmy D. Staton	21,398	5,000	53,333	79,731	—
E. Paul Hilton	29,442	5,000	92,599	127,041	—
Edward J. Rivas	47,524	5,000	98,799	151,323	—
David A. Christian	22,276	6,667	123,867	152,810	—
James P. O'Hanlon[3]	102,250	8,333	280,000	390,583	—
Edgar M. Roach, Jr.[3]	142,180	10,000	360,000	512,180	1,647
All officers as a group (15 persons)[4]	540,479	81,948	1,780,201	2,402,628	79

(1) Amounts in this column represent share equivalents and do not have voting rights. At a director's or executive's election, cash compensation is deferred until a specified age, future date or retirement and will be distributed in cash.
(2) Messrs. Capps and Farrell disclaim ownership for 17,187 and 399 shares, respectively.
(3) Messrs. O'Hanlon and Roach's ownership is reported as of December 1, 2002, the date they ceased to be executive officers.
(4) All directors and executive officers as a group own less 1 percent of the number of Dominion common shares outstanding at February 21, 2003.

Item 13. Certain Relationships and Related Transactions

See Item 11. Executive Compensation—*Executive Stock Purchase Programs*, for information concerning certain transactions with executive officers under the Executive Stock Purchase and Loan Program.

The Company leases fiber optic capacity to Dominion Telecom, Inc. at rates subject to the approval of the Virginia Commission. For additional information on this matter, see Note 24 to the Consolidated Financial Statements.

Item 14. Controls and Procedures

Senior management, including the Chief Executive Officers and Chief Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures within 90 days of the date of this report. Based on this evaluation process, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective. Since that evaluation process was completed, there have been no significant changes in internal controls or in other factors that could significantly affect these controls.

Part IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) The following documents are filed as part of this Form 10-K:

1. Financial Statements

   See Index on Page 32

2. Financial Statement Schedules

All other schedules are omitted because they are not applicable, or the required information is shown in the financial statements or the related notes.

3. Exhibits

3.1 Restated Articles of Incorporation, as amended, as in effect May 6, 1999, as amended December 6, 2002 (filed herewith).

3.2 Bylaws, as amended, as in effect on April 28, 2000 (Exhibit 3, Form 10-Q for the quarter ended March 31, 2000, File No. 1-2255, incorporated by reference).

4.1 See Exhibit 3.1 above.

4.2 Indenture of Mortgage of Virginia Electric and Power Company, dated November 1, 1935, as supplemented and modified by fifty-eight Supplemental Indentures (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255, incorporated by reference); Sixty-Seventh Supplemental Indenture (Exhibit 4(i), Form 8-K, dated April 2, 1991, File No. 1-2255, incorporated by reference); Seventieth Supplemental Indenture, (Exhibit 4(iii), Form 8-K, dated February 25, 1992, File No. 1-2255, incorporated by reference); Seventy-First Supplemental Indenture (Exhibit 4(i)) and Seventy-Second Supplemental Indenture, (Exhibit 4(ii), Form 8-K, dated July 7, 1992, File No. 1-2255, incorporated by reference); Seventy-Third Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated August 6, 1992, File No. 1-2255, incorporated by reference); Seventy-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 10, 1993, File No. 1-2255, incorporated by reference); Seventy-Fifth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated April 6, 1993, File No. 1-2255, incorporated by reference); Seventy-Sixth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated April 21, 1993, File No. 1-2255, incorporated by reference); Seventy-Seventh Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated June 8, 1993, File No. 1-2255, incorporated by reference); Seventy-Eighth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated August 10, 1993, File No. 1-2255, incorporated by reference); Seventy-Ninth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated August 10, 1993, File No. 1-2255, incorporated by reference); Eightieth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated October 12, 1993, File No. 1-2255, incorporated by reference); Eighty-First Supplemental Indenture, (Exhibit 4(iii), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference); Eighty-Second Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated January 18, 1994, File No. 1-2255, incorporated by reference); Eighty-Third Supplemental Indenture (Exhibit 4(i), Form 8-K, dated October 19, 1994, File No. 1-2255, incorporated by reference); Eighty-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated March 23, 1995, File No. 1-2255, incorporated by reference); and Eighty-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 20, 1997, File No. 1-2255, incorporated by reference).

4.3 Indenture, dated as of June 1, 1986, between Virginia Electric and Power Company and JP Morgan Chase Bank (formerly The Chase Manhattan Bank and Chemical Bank) (Exhibit 4(v), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference).

4.4 Indenture, dated April 1, 1988, between Virginia Electric and Power Company and JP Morgan Chase Bank (formerly The Chase Manhattan Bank and Chemical Bank), as supplemented and modified by a First Supplemental Indenture, dated August 1, 1989, (Exhibit 4(vi), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference); Second Supplemental Indenture, dated May 1, 1999 (Exhibit 4.2, Form S-3, File No. 333-7615, as filed on April 13, 1999, incorporated by reference).

4.5 Subordinated Note Indenture, dated as of August 1, 1995 between Virginia Electric and Power Company and JP Morgan Chase Bank (formerly The Chase Manhattan Bank and Chemical Bank), as Trustee (Exhibit 4(a), Form S-3 Registration Statement File No. 333-20561 as filed on January 28, 1997, incorporated by reference), Form of Second Supplemental Indenture (Exhibit 4.6, Form 8-K filed August 20, 2002, No. 1-2255, incorporated by reference).

4.6 Form of Senior Indenture, dated as of June 1, 1998, between Virginia Electric and Power Company and JP Morgan Chase Bank (formerly The Chase Manhattan Bank), (Exhibit 4(ii), Form S-3 Registration Statement File No. 333-47119, as filed on February 27, 1997, incorporated by reference) as supplemented by the First Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 3, 1999, File No.1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K, dated October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); and Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated January 24, 2002, incorporated by reference); Seventh Supplemental Indenture dated September 1, 2002 (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Eighth Supplemental Indenture (Exhibit 4.2, Form 8-K filed February 27, 2000, File No. 1-2255, incorporated by reference).

4.7 Virginia Electric and Power Company agrees to furnish to the Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of Dominion Resources, Inc.'s total consolidated assets.

10.1 Amended and Restated Interconnection and Operating Agreement, dated as of July 29, 1997 between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 1.3, Form 10-K for the fiscal year ended December 31, 1997, File No. 1-2255, incorporated by reference).

10.2 Services Agreement between Dominion Resources Services, Inc. and Virginia Electric and Power Company dated January 1, 2000 (Exhibit 10.19, Form 10-K for the fiscal year ended December 31, 1999, File No. 1-2255, incorporated by reference).

10.3 Support Agreement between Dominion Resources Services, Inc. and Virginia Electric and Power Company dated January 1, 2000 (Exhibit 10.20, Form 10-K for the fiscal year ended December 31, 1999, File No. 1-2255, incorporated by reference).

10.4 PJM South Implementation Agreement between Virginia Electric and Power Company and PJM Interconnection, L.L.C., dated September 30, 2002 as amended December 6, 2002 (filed herewith).

10.5 $1,250,000,000 364-Day Credit Agreement among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company and JPMorgan Chase Bank, as Administrative Agent for the Lenders, dated as of May 30, 2002 (filed herewith).

10.6 $750,000,000 Three-Year Credit Agreement among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company and JPMorgan Chase Bank, as Administrative Agent for the Lenders, dated as of May 30, 2002 (filed herewith).

10.7* Dominion Resources, Inc. Executive Supplemental Retirement Plan, effective January 1, 1981 as amended and restated September 1, 1996 (with amendment dated June 20, 1997 and amendment effective February 20, 1998 (Exhibit 10.14, Form 10-K for the fiscal year ended December 31, 1997, File No. 1-2255, incorporated by reference); amendment dated November 26, 2001 (Exhibit 10.6, Form 10-K for the fiscal year ended December 31, 2001, File No. 1-2255, incorporated by reference).

10.8* Dominion Resources, Inc.'s Cash Incentive Plan as adopted December 20, 1991 (Exhibit 10(xxv), Form 10-K for the fiscal year ended December 31, 1991, File No. 1-2255, incorporated by reference).

10.9* Dominion Resources, Inc. Incentive Compensation Plan, effective April 22, 1997, as amended and restated effective July 20, 2001 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2001, File No. 1-2255, incorporated by reference).

10.10* Dominion Resources, Inc. Executive Stock Purchase and Loan Plan Phase II, dated February 15, 2000 (filed herewith).

10.11* Dominion Resources, Inc. Retirement Benefit Funding Plan, effective June 29, 1990 as amended and restated September 1, 1996 (Exhibit 10.16, Form 10-K for the fiscal year ended December 31, 1997, File No. 1-2255, incorporated by reference).

10.12* Dominion Resources, Inc. Retirement Benefit Restoration Plan as adopted effective January 1, 1991 as amended and restated September 1, 1996 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 1997, File No. 1-2255, incorporated by reference); amendment dated November 26, 2001 (Exhibit 10.9, Form 10-K for the fiscal year ended December 31, 2001, File No. 1-2255, incorporated by reference).

10.13* Dominion Resources, Inc. Executives' Deferred Compensation Plan, effective January 1, 1994 and as amended and restated January 1, 2003 (filed herewith).

10.14* Dominion Resources, Inc. Leadership Stock Option Plan, effective July 1, 2000, as amended and restated effective July 20, 2001 (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2001, File No. 1-8489, incorporated by reference).

10.15* Dominion Resources, Inc. Executive Stock Purchase Tool Kit, effective September 1, 2001 as restated December 20, 2002 (filed herewith).

10.16* Dominion Resources, Inc. Security Option Plan, effective January 1, 2003 (filed herewith)

10.17* Omitted.

10.18* Omitted.

10.19* Letter agreement between the Company and Thomas F. Farrell, II (filed herewith).

10.20* Form of Employment Continuity Agreement for certain officers of Dominion including Messrs. Farrell, Christian, Staton, Rivas, Johnson and Hilton (Exhibit 10.2), Form 10-Q for the quarter ended June 30, 1999, File No. 1-2255, incorporated by reference) and as amended October 19, 2001 (Exhibit 10.15, Form 10-K for the fiscal year ended December 31, 2001, File No. 1-2255, incorporated by reference).

10.21* Form of Executive Supplemental Retirement Plan Lifetime Benefits for certain officers of the Company including Mr. Hilton (Exhibit 10.19, Form 10-K for the fiscal year ended December 31, 2001, File No. 1-2255, incorporated by reference).

10.22* Employment Agreement dated August 1, 2000 between the Company and Jimmy D. Staton (Exhibit 10.24, Form 10-K for the fiscal year ended December 31, 2001, File No. 1-2255, incorporated by reference).

10.23* Supplemental Retirement Agreement dated December 12, 2000, between the Company and David A. Christian (Exhibit 10.25, Form 10-K for the fiscal year ended December 31, 2001, File No. 1-2255, incorporated by reference).

10.24* Memorandum regarding Terms of Retirement and related general release dated October 23, 2002 between Dominion and Edgar M. Roach, Jr. (Exhibit 10.2, Form 10-Q for the quarter ended September 30, 2002, File No. 1-2255, incorporated by reference).

10.25* Memorandum regarding Terms of Retirement and related general release dated November 5, 2002 between Dominion and James P. O'Hanlon (Exhibit 10.3, Form 10-Q for the quarter ended September 30, 2002, File No. 1-2255, incorporated by reference).

10.26* Offer of employment dated August 21, 2000 between Dominion Energy, Inc. and Jay L. Johnson (filed herewith).

10.27* Supplemental Agreement dated July 29, 2002 between Dominion Resources Services, Inc. and Edward J. Rivas (filed herewith).

12.1 Ratio of earnings to fixed charges (Exhibit 12, Form 8-K filed February 27, 2003, File No. 1-2255, incorporated by reference).

12.2 Ratio of earnings to fixed charges and dividends (filed herewith).

18.1 Letter re: Change in Accounting Principles (Exhibit 18, Form 10-Q for the quarter ended September 30, 2000, File No. 1-2255, incorporated by reference).

21 Subsidiaries of the Registrant (filed herewith).

23.1 Consent of Deloitte & Touche LLP (filed herewith).

23.2 Consent of Jackson & Kelly (filed herewith).

23.3 Consent of McGuireWoods LLP (filed herewith).

99.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

99.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

99.3 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

99.4 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

99.5 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

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* Indicates management contract or compensatory plan or arrangement.

(b) Reports on Form 8-K

1. The Company filed a report on Form 8-K on December 10, 2002, relating to the sale of 1,250 Units (the Units, each unit consisting of 1,000 shares) of Flexible Money Market Cumulative Preferred Stock 2002 Series A (Liquidation preference $100 per share).

2. The Company filed a report on Form 8-K on February 23, 2003, relating to the sale of $400,000,000 aggregate principal amount of the Company's 2003 Series A 4.75% Senior Notes due 2013.

Independent Auditors' Report

To Board of Directors of
Virginia Electric and Power Company
Richmond, Virginia

We have audited the consolidated financial statements of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries as of December 31, 2002 and 2001, and for each of the three years in the period ended December 31, 2002, and have issued our report thereon dated January 21, 2003, which report expresses an unqualified opinion and includes an explanatory paragraph as to changes in accounting principle for derivative instruments and hedging activities in 2001 and the method of accounting used to develop the market-related value of pension plan assets in 2000; such consolidated financial statements and report are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company, listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated 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.

/s/ DELOITTE & TOUCHE LLP

Richmond, Virginia
January 21, 2003

Virginia Electric and Power Company
Schedule II—Valuation and Qualifying Accounts

Column A		Column B	Column C		Column D	Column E
			Additions			
Description		Balance at Beginning of Period	Charged to Expense	Charged to Other Accounts	Deductions	Balance at End of Period
				(Millions)		
Valuation and qualifying accounts which are deducted in the balance sheet from the assets to which they apply:						
Allowance for doubtful accounts	2000	12	18	—	14[a]	16
	2001	16	18	—	11[a]	23
	2002	23	15	—	26[a]	12
Valuation allowance for commodity contracts	2000	22	(3)[b]	—	—	19
	2001	19	7[b]	—	—	26
	2002	26	(2)[b]	—	—	24
Reserves:						
Liability for pre-2001 workforce reductions	2000	4	—	—	4[c]	—
	2001	—	—	—	—	—
	2002	—	—	—	—	—
Liabilities for restructuring costs:						
2000 Plan						
Severance and related costs	2000	—	14	—	8[c]	6
	2001	6	(1)[b]	—	5[c]	—
	2002	—	—	—	—	—
2001 Plan						
Severance and related costs	2001	—	16	—	—	16
	2002	16	(7)[b]	—	5[c]	4

(a) Represents net amounts charged-off as uncollectible.
(b) Represents adjustments reflecting changes in estimates
(c) Represents payments for workforce reductions and/or restructuring liabilities

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.

VIRGINIA ELECTRIC AND POWER COMPANY

By: /s/ THOS. E. CAPPS
(Thos. E. Capps, Chairman of the Board of Directors)

Date: March 20, 2003

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 20th day of March, 2003.

Signature	Title
/s/ THOS. E. CAPPS **Thos. E. Capps**	Chairman of the Board of Directors
/s/ THOMAS N. CHEWNING **Thomas N. Chewning**	Director
/s/ THOMAS F. FARRELL, II **Thomas F. Farrell, II**	President, Chief Executive Officer and Director
/s/ JAY L. JOHNSON **Jay L. Johnson**	President and Chief Executive Officer
/s/ PAUL D. KOONCE **Paul D. Koonce**	Chief Executive Officer – Transmission
/s/ MARK F. MCGETTRICK **Mark F. McGettrick**	President and Chief Executive Officer – Generation
/s/ G. SCOTT HETZER **G. Scott Hetzer**	Senior Vice President and Treasurer (Principal Financial Officer)
/s/ STEVEN A. ROGERS **Steven A. Rogers**	Vice President (Principal Accounting Officer)

Certifications

I, Thomas F. Farrell, II, certify that:

1. I have reviewed this annual report on Form 10-K of Virginia Electric and Power Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

    a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

    b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

    c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses

Date: March 20, 2003

By: /s/ THOMAS F. FARRELL, II
Thomas F. Farrell, II
President and Chief Executive Officer

I, Jay L. Johnson, certify that:

1. I have reviewed this annual report on Form 10-K of Virginia Electric and Power Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 20, 2003

By: /s/ JAY L. JOHNSON
Jay L. Johnson
President and Chief Executive Officer

I, Paul D. Koonce, certify that:

1. I have reviewed this annual report on Form 10-K of Virginia Electric and Power Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses

Date: March 20, 2003

By: /s/ PAUL D. KOONCE
Paul D. Koonce
Chief Executive Officer – Transmission

I, Mark F. McGettrick, certify that:

1. I have reviewed this annual report on Form 10-K of Virginia Electric and Power Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 20, 2003

By: /s/ MARK F. MCGETTRICK
Mark F. McGettrick
President and Chief Executive Officer – Generation

I, G. Scott Hetzer, certify that:

1. I have reviewed this annual report on Form 10-K of Virginia Electric and Power Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 20, 2003

By. /s/ G. SCOTT HETZER

G. Scott Hetzer
Senior Vice President and Treasurer
(Principal Financial Officer)