VIRGINIA ELECTRIC & POWER CO
Form 10-K
February 26, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

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 001-02255

VIRGINIA ELECTRIC AND POWER COMPANY

(Exact name of registrant as specified in its charter)

Virginia	**54-0418825**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
120 Tredegar Street	
Richmond, Virginia	**23219**
(Address of principal executive offices)	**(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

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

None

Indicate by check mark whether the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ¨ No x

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 x No ¨

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

The aggregate market value of the voting stock held by non-affiliates as of the last business day of the registrant s most recently completed second fiscal quarter was zero.

As of February 1, 2009, there were issued and outstanding 209,833 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

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Virginia Electric and Power Company

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Glossary of Terms

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
affiliates	Other Dominion subsidiaries
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income (loss)
CEO	Chief Executive Officer
CFO	Chief Financial Officer
DOE	Department of Energy
Dominion	Dominion Resources, Inc.
DRS	Dominion Resources Services, Inc., a subsidiary of Dominion
DVP	Dominion Virginia Power operating segment
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation No.
Fitch	Fitch Ratings Ltd.
FSP	FASB Staff Position
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
kWh	Kilowatt-hour
Lehman	Lehman Brothers Holdings, Inc.
MD&A	Management s Discussion and Analysis of Financial Condition and Results of Operations
Moody s	Moody s Investors Service
Mw	Megawatt
mwhrs	Megawatt hours
NERC	North American Electric Reliability Corporation
North Anna	North Anna power station
North Carolina Commission	North Carolina Utilities Commission
NRC	Nuclear Regulatory Commission
ODEC	Old Dominion Electric Cooperative
Pennsylvania Commission	Pennsylvania Public Utility Commission
PJM	PJM Interconnection, LLC
ROE	Return on equity
RTO	Regional transmission organization
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
Standard & Poor s	Standard & Poor s Ratings Services, a division of the McGraw-Hill Companies, Inc.
Surry	Surry power station
U.S.	United States of America
VIEs	Variable interest entities
Virginia Commission	Virginia State Corporation Commission
West Virginia Commission	Public Service Commission of West Virginia

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Part I

Item 1. Business

THE COMPANY

Virginia Electric and Power Company (Virginia Power) is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. As of December 31, 2008, we served approximately 2.4 million retail customer accounts, including governmental agencies, as well as wholesale customers such as rural electric cooperatives and municipalities. In Virginia, we conduct business under the name Dominion Virginia Power. In North Carolina, we conduct business under the name Dominion North Carolina Power and serve retail customers located in the northeastern region of the state, excluding certain municipalities. In addition, we sell electricity at wholesale to rural electric cooperatives, municipalities and into wholesale electricity markets.

The terms Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Virginia Power, one or more of its consolidated subsidiaries or operating segments or the entirety of Virginia Power and its consolidated subsidiaries. All of our common stock is owned by our parent company, Dominion Resources, Inc. (Dominion).

As of December 31, 2008, we had approximately 7,500 full-time employees. Approximately 3,400 employees are subject to collective bargaining agreements.

We were incorporated in 1909 as a Virginia public service corporation. Our principal executive offices are located at 120 Tredegar Street, Richmond, Virginia 23219 and our telephone number is (804) 819-2000.

OPERATING SEGMENTS

We manage our daily operations through two primary operating segments: Dominion Virginia Power (DVP) and Generation. We also report a Corporate and Other segment that primarily includes specific items attributable to our operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments. While we manage our daily operations through our operating segments as described below, our assets remain wholly-owned by us and our legal subsidiaries.

For additional financial information on business segments and geographic areas, including revenues from external customers, see Notes 1 and 23 to our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data. For additional information on operating revenue related to our principal products and services, see Note 2 to our Consolidated Financial Statements.

DVP

DVP includes our regulated electric transmission, distribution and customer service operations. Our electric transmission and distribution operations serve residential, commercial, industrial and governmental customers in Virginia and northeastern North Carolina.

Revenue provided by our electric distribution operations is based primarily on rates established by state regulatory authorities and state law. Changes in revenue are driven primarily by weather, customer growth and other factors impacting consumption such as the economy and energy conservation.

Operationally, electric distribution continues to focus on improving service levels while striving to reduce costs and link investments to operational results. As part of this continued focus, we have implemented an asset management process to ensure that we are optimizing our investments to balance cost, performance and risk. We are also using technology to enhance customer service options. As we move toward the future, safety, operational performance and customer relationships will remain as key focal areas. Variability in earnings results from changes in rates, the demand for services, and operating and maintenance expenditures.

As discussed in *Status of Electric Regulation in Virginia* under *Regulation*, the Virginia General Assembly enacted legislation in April 2007 that institutes a modified cost-of-service rate model for the Virginia jurisdiction of our utility operations, subject to base rate caps in effect through December 31, 2008. We currently anticipate that the 2009 base rate review will result in an increase in rates, however we cannot predict the outcome of future rate actions at this time.

Revenue provided by our electric transmission operations is based primarily on rates approved by FERC. The profitability of this business is dependent on its ability, through the rates it is permitted to charge, to recover costs and earn a reasonable return on its capital investments. Variability in earnings results from changes in rates and the timing of property additions, retirements and depreciation.

In April 2008, FERC granted an application by our electric transmission operations to establish a forward-looking formula rate mechanism that will update transmission rates on an annual basis and approved a return on equity (ROE) of 11.4% on the common equity base of these operations, effective as of January 1, 2008. The FERC ruling did not materially impact our results of operations; however, going forward the FERC-approved formula method will allow us to earn a more current return on our growing investment in electric transmission infrastructure.

In addition, in August 2008, FERC granted an application by our electric transmission operations requesting a revision to our cost of service to reflect an additional ROE incentive adder for eleven electric transmission enhancement projects and approved an incentive of 1.5% for four of the projects and an incentive of 1.25% for the other seven. See *Federal Regulations* in *Regulation* for additional information.

We are a member of PJM, a regional transmission organization (RTO), and our electric transmission facilities are integrated into PJM wholesale electricity markets. Consistent with the increased authority given to the North American Electric Reliability Corporation (NERC) by the Energy Policy Act of 2005 (EPACT), we are committed to meeting NERC standards, modernizing our infrastructure and maintaining superior system reliability. We will continue to focus on safety, operational performance and execution of PJM s Regional Transmission Expansion Plan (RTEP).

Operationally, DVP continues to enhance the customer experience through solid reliability performance and by providing our customers the ability to manage their accounts on-line. At the end of 2008, over 600,000 of DVP s customers were signed up to manage their account on-line through dom.com and over 2 million transactions were performed. This reflects a transaction increase of 28% over 2007. Customers typically use the Internet

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for routine billing and payment transactions; however, we expect the addition of new 2008 options like connecting and disconnecting service and reporting outages and obtaining outage updates to continue to increase on-line usage.

Competition

Within DVP s service territory in Virginia and North Carolina, there is no competition for electric distribution service. Additionally, since our electric transmission facilities are integrated into PJM, our electric transmission services are administered by PJM and are not subject to competition in relation to transmission service provided to customers within the PJM region. In our transmission and distribution operations, we are seeing continued growth in new customers.

Regulation

DVP s electric retail service, including the rates it may charge to jurisdictional customers, is subject to regulation by the Virginia Commission and the North Carolina Commission. DVP s electric transmission rates, tariffs and terms of service are subject to regulation by FERC. Electric transmission siting authority remains the jurisdiction of the Virginia and North Carolina Commissions. However, EPACT provides FERC with certain backstop authority for transmission siting. See *State Regulations* and *Federal Regulations* in *Regulation* for additional information.

Properties

DVP has approximately 6,000 miles of electric transmission lines of 69 kilovolt (kV) or more located in the states of North Carolina, Virginia and West Virginia. Portions of DVP s electric transmission lines cross national parks and forests under permits entitling the federal government to use, at specified charges, any surplus capacity that may exist in these lines. While we own and maintain our electric transmission facilities, they are a part of PJM, which coordinates the planning, operation, emergency assistance, and exchange of capacity and energy for such facilities.

Each year, as part of PJM s RTEP process, reliability projects are authorized. In June 2006, PJM authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects, which are designed to improve the reliability of service to our customers and the region, and are subject to applicable state and federal permits and approvals.

The first project is an approximately 270-mile 500-kV transmission line that begins in southwestern Pennsylvania, crosses West Virginia, and terminates in northern Virginia, of which we will construct approximately 65 miles in Virginia (Meadow Brook-to-Loudoun line) and a subsidiary of Allegheny Energy, Inc. (Trans-Allegheny Interstate Line Company) will construct the remainder. In October 2008, the Virginia Commission authorized construction of the Meadow Brook-to-Loudoun line and affirmed the 65-mile route we proposed for the line which is adjacent to, or within, existing transmission line right-of-ways. The Virginia Commission s approval of the Meadow Brook-to-Loudoun line was conditioned on the respective state commission approvals of both the West Virginia and Pennsylvania portions of the transmission line. The West Virginia Commission s approval of Trans-Allegheny Interstate Line Company s application became effective in February 2009 and the Pennsylvania Commission granted approval in December 2008. In February 2009, Petitions for Appeal of the Virginia

Commission s approval of the Meadow Brook-to-Loudoun line were filed with the Supreme Court of Virginia by the Piedmont Environmental Council and others. The Meadow Brook-to-Loudoun line is expected to cost approximately $255 million and, subject to the receipt of all regulatory approvals, is expected to be completed in June 2011.

The second project is an approximately 60-mile 500-kV transmission line that we will construct in southeastern Virginia (Carson-to-Suffolk line). In October 2008, the Virginia Commission authorized the construction of the Carson-to-Suffolk line. This project is estimated to cost $224 million and is expected to be completed in June 2011. These transmission upgrades are designed to improve the reliability of service to our customers and the region. The siting and construction of these transmission lines are subject to applicable state and federal permits and approvals.

In addition, DVP s electric distribution network includes approximately 56,000 miles of distribution lines, exclusive of service level lines, in Virginia and North Carolina. The grants for most of our electric lines contain right-of-ways that have been obtained from the apparent owner of real estate, but underlying titles have not been examined. Where right-of-ways 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.

Sources of Energy Supply

DVP s supply of electricity to serve retail customers is produced or procured by the Generation segment. See *Generation* for additional information.

Seasonality

DVP s earnings vary seasonally as a result of the impact of changes in temperature and the availability of alternative sources for heating on demand by residential and commercial customers. Generally, the demand for electricity peaks during the summer and winter months to meet cooling and heating needs. In addition, an increase in heating degree days does not produce the same increase in revenue as an increase in cooling degree days due to seasonal pricing differentials and because alternative heating sources are more readily available.

Generation

Generation includes our portfolio of electric generation facilities, power purchase agreements and our energy supply operations. Our electric generation operations primarily serve the supply requirements for our DVP segment s customers. Our generation mix is diversified and includes coal, nuclear, gas, oil, and renewables. Our electric generation operations serve customers in Virginia and northeastern North Carolina. Our generation facilities are located in Virginia, West Virginia and North Carolina. Our energy supply operations are responsible for managing energy and capacity needs for our utility operations. As discussed in *Properties*, we have plans to add additional generation capacity to satisfy future growth in our utility service area.

Our earnings primarily result from the sale of electricity we generate. Due to 1999 Virginia deregulation legislation, as amended in 2004 and 2007, revenues for serving Virginia jurisdictional retail load were based on capped rates through 2008. Additionally, fuel costs, including purchased power, were subject to fixed-rate recovery provisions until July 1, 2007. Pursuant to the 2007 amendments to the fuel cost recovery statute,

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annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were reinstituted beginning July 1, 2007 for our Virginia jurisdictional customers. As discussed in *Status of Electric Regulation in Virginia* under *Regulation*, the Virginia General Assembly enacted legislation in April 2007 that returned the Virginia jurisdiction of our generation operations to a modified cost-of-service rate model, subject to base rate caps in effect through December 31, 2008. As a result, we reapplied the provisions of SFAS No. 71 to those operations on April 4, 2007, the date the legislation was enacted. We currently anticipate that the 2009 base rate review will result in an increase in rates, however we cannot predict the outcome of future rate actions at this time. Variability in earnings for our utility operations results from changes in rates, the demand for services, which is primarily weather dependent, and labor and benefit costs, as well as the timing, duration and costs of scheduled and unscheduled outages.

Competition

Retail choice was made available to our Virginia jurisdictional electric customers beginning January 1, 2003; however, no significant competition developed in Virginia. In April 2007, the Virginia General Assembly passed legislation ending retail choice for most of our Virginia jurisdictional electric utility customers, effective January 1, 2009. See *Regulation State Regulations*. Currently, North Carolina does not offer retail choice to electric customers.

Regulation

Operations are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA), the Department of Energy (DOE), the Army Corps of Engineers, the Virginia Commission, the North Carolina Commission and other federal, state and local authorities. See *State Regulations* and *Federal Regulations* in *Regulation* for more information.

Properties

For a listing of current generation facilities, see Item 2. Properties.

Based on available generation capacity and current estimates of growth in customer demand in our utility service area, we will need additional generation capacity over the next ten years. We have announced a comprehensive generation growth program, referred to as *Powering Virginia*, which involves the development, financing, construction and operation of new multi-fuel, multi-technology generation capacity to meet the growing demand in our core market in Virginia. As part of this program, the following projects are in various stages of development:

In June 2008, we commenced the operation of two additional natural gas-fired electric generating units (Units 3 and 4) totaling 321 Mw at our Ladysmith power station (Ladysmith) to supply electricity during periods of peak demand. Construction has commenced on a fifth combustion turbine (Unit 5) which is expected to begin operations in mid-2009.

In July 2007, we filed an application with the Virginia Commission requesting approval to construct and operate a 585 Mw (nominal) carbon-capture compatible, clean-coal powered electric generation facility (Virginia City Hybrid Energy Center) to be located in Wise County, Virginia. The Virginia Commission issued a final order in March 2008 (Final Order), approving a certificate to construct and operate the proposed Virginia City

Hybrid Energy Center, granting approval for us to continue to accrue AFUDC until capped rates end and approving a rate adjustment clause, allowing us current recovery of financing costs beginning January 1, 2009, as specified in the Final Order. In its Final Order, the Virginia Commission approved an initial return on common equity for the facility of 12.12%, consisting of a base return of 11.12% plus a 100 basis point premium that Virginia law provides for new conventional coal generation facilities. The Virginia Commission also authorized us to apply for an additional 100 basis point premium upon a demonstration that the plant is carbon-capture compatible. The enhanced return will apply to the Virginia City Hybrid Energy Center during construction and through the first twelve years of the facility s service life. In July 2008, the Southern Environmental Law Center (SELC), on behalf of four environmental groups, filed a Petition for Appeal of the Final Order with the Supreme Court of Virginia. A decision is expected in April 2009.

An application for a permit to construct and operate the Virginia City Hybrid Energy Center, in compliance with federal and state air pollution laws, was filed in July 2006 with the Virginia Department of Environmental Quality and an application for another air permit for hazardous emissions was filed in February 2008. In June 2008, the Virginia Air Pollution Control Board (the Air Board), which assumed consideration of the applications, approved and issued both permits. The Air Board approved lower emissions limits than had been requested, including limits for sulfur dioxide (SO_2) and mercury. The Air Board also adopted our proposal to convert our Bremo power station from coal to natural gas within two years of the Virginia City Hybrid Energy Center going into service. The Bremo conversion project is part of our overall effort to reduce air emissions and is contingent upon the Virginia City Hybrid Energy Center entering service and Bremo receiving all necessary approvals, including approval from the Virginia Commission. See *Environmental Strategy* for more information. Construction of the Virginia City Hybrid Energy Center has commenced and the facility is expected to be in operation by 2012 at an estimated cost of approximately $1.8 billion, excluding financing costs. In August 2008, the SELC, on behalf of four environmental groups, filed Petitions for Appeal in Richmond Circuit Court challenging the approval of both of the air permits.

We are considering the construction of a third nuclear unit at a site located at North Anna power station (North Anna), which we own along with Old Dominion Electric Cooperative (ODEC). In November 2007, the NRC issued an Early Site Permit (ESP) to our affiliate, Dominion Nuclear North Anna, LLC (DNNA). Also in November 2007, we along with ODEC, filed an application with the NRC for a Combined Construction Permit and Operating License (COL) that references a specific reactor design and which would allow us to build and operate a new nuclear unit at North Anna. In January 2008, the NRC accepted our application for the COL and deemed it complete. In December 2008, we terminated a long-lead agreement with our vendor with respect to the reactor design identified in our COL application and certain related equipment. We intend to conduct a competitive process in 2009 to determine if vendors can provide an advanced technology reactor that could be licensed and built under terms acceptable to us. If, as a result of this process, we choose a different reactor design, we will amend our COL

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application, as necessary. We have not yet committed to building a new nuclear unit.

The NRC is required to conduct a hearing in all COL proceedings. In August 2008, the Atomic Safety and Licensing Board of the NRC granted a request for a hearing on one of eight contentions filed by the Blue Ridge Environmental Defense League. The mandatory NRC hearing will be uncontested with respect to other issues. Dominion has a cooperative agreement with the DOE to share equally the cost of developing the COL. In April 2008, Dominion filed applications with the Virginia Commission and the North Carolina Commission seeking approval to merge DNNA into Virginia Power. The Virginia and North Carolina applications were approved in July and September 2008, respectively, and DNNA was merged into Virginia Power effective December 1, 2008. Also in April 2008, Dominion filed an application with the NRC to transfer the ESP from DNNA to Virginia Power and ODEC. This application was approved in October 2008, and the ESP has been transferred to Virginia Power and ODEC.

In June 2008, the DOE issued a solicitation announcement inviting the submission of applications for loan guarantees from the DOE under its Loan Guarantee Program in support of debt financing for nuclear power facility projects in the U.S. (the Solicitation). The Solicitation is specifically designed to provide loan guarantees to support those projects that employ new or significantly improved nuclear power facility technologies. Any loan guarantee which may be issued by the DOE pursuant to the Solicitation would be backed by the full faith and credit of the U.S. government, and would provide credit enhancement for all or a portion of the debt financing an applicant would incur with respect to such a project. In August 2008, we submitted to the DOE Part I of the application, including a high-level description of the proposed nuclear unit, project eligibility, financing strategy and progress to date related to critical path schedules. In December 2008, we submitted to the DOE Part II of the application. DOE is in the process of evaluating our application, together with all other substantially completed applications submitted.

In March 2008, we purchased a power station development project in Buckingham County, Virginia (Bear Garden) that, once constructed, will generate about 590 Mw. The project already has air and water permits for a combined-cycle, natural gas-fired power station; however, such permits may need to be modified. In addition, construction of the project is subject to approval by the Virginia Commission, including approval under state regulations relating to bidding for the purchase of electric capacity and energy from other power suppliers, and the receipt of other environmental permits. A gas pipeline will also need to be constructed to provide gas supply to the power station. In March 2008, we filed an application with the Virginia Commission for authority to build the proposed combined-cycle, natural gas-fired power station and transmission interconnection line for an estimated $619 million, excluding financing costs. Pending the receipt of regulatory approval, we expect operations to begin in the summer of 2011.

In March 2008, we also purchased a power station development project in Warren County, Virginia for future development. If developed, the project will involve the construction of a combined cycle, natural gas-fired power station expected to generate

about 600 Mw of electricity and will be subject to necessary regulatory approvals. In January 2009, we announced a joint effort with BP Alternative Energy, Inc. (BP) to evaluate wind energy projects in Tazewell County and Wise County, Virginia which, if completed, would increase our renewable energy capacity.

Sources of Energy Supply

We use a variety of fuels to power our electric generation and purchase power for system load requirements, as described below.

	2008 Source	2007 Source	2006 Source
Coal[1]	**33%**	35%	38%
Nuclear[2]	**31**	29	31
Purchased power, net	**29**	28	26
Natural gas	**6**	6	4
Oil	**1**	2	1
Total	**100%**	100%	100%

(1) Excludes ODEC s 50% ownership interest in the Clover Power Station. The average cost of coal for 2008 Virginia in-system generation was $28.02 per Mw hour.
(2) Excludes ODEC s 11.6% ownership interest in North Anna.

Nuclear Fuel Generation primarily utilizes long-term contracts to support its nuclear fuel requirements. Some of these agreements have fixed commitments and are included as contractual obligations in *Future Cash Payments for Contractual Obligations and Planned Capital Expenditures* in Item 7. MD&A. Worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices which are dependent on the market environment. Current agreements, inventories and spot market availability are expected to support current and planned fuel supply needs through 2014. Additional fuel is purchased as required to ensure optimal cost and inventory levels.

Fossil Fuel Generation primarily utilizes coal, oil and natural gas in its fossil fuel plants. Generation s coal supply is obtained through long-term contracts and short-term spot agreements from both domestic and international suppliers.

Generation s natural gas and oil supply is obtained from various sources including: purchases from major and independent producers in the Mid-Continent and Gulf Coast regions; purchases from local producers in the Appalachian area; purchases from gas marketers; and withdrawals from underground storage fields owned by Dominion or third parties.

Generation manages a portfolio of natural gas transportation contracts (capacity) that allows flexibility in delivering natural gas to our gas turbine fleet, while minimizing costs.

Purchased Power Generation purchases electricity from the PJM spot market and through power purchase agreements with other suppliers to provide for system load requirements.

Seasonality

Sales of electricity for Generation typically vary seasonally as a result of the impact of changes in temperature and the availability of alternative sources for heating on demand by residential and commercial customers. Generally, the demand for electricity peaks during the summer and winter months to meet cooling and heating needs. In addition, an increase in heating degree days does not produce the same increase in revenue as an increase in cooling degree days due to seasonal pricing differentials and because alternative heating sources are more readily available.

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NUCLEAR DECOMMISSIONING

Generation has a total of four licensed, operating nuclear reactors at its Surry power station (Surry) and North Anna, in Virginia, that serve customers of our regulated operations.

We have decommissioning obligations for each of these power stations, as discussed in Note 12 to our Consolidated Financial Statements. Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power station once operations have ceased, in accordance with standards established by the NRC. Amounts collected from ratepayers and placed into trusts have been invested to fund the expected future costs of decommissioning the Surry and North Anna units.

While the current economic downturn has resulted in a decrease in the value of investments held by our nuclear decommissioning trusts, we continue to believe that the amounts currently available in our decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for our Surry and North Anna units especially when combined with ratepayer collections and contributions to the decommissioning trusts, if such future collections and contributions are required. This reflects our long-term investment horizon, since the units will not be decommissioned for decades, and our positive long-term outlook for trust fund investment returns. We will continue to monitor these trusts to ensure they meet the minimum financial assurance requirement, which may include the use of parent company guarantees, surety bonding or other financial guarantees recognized by the NRC.

The total estimated cost to decommission our four nuclear units is $2.0 billion in 2008 dollars and is primarily based upon site-specific studies completed in 2006. The current cost estimates assume decommissioning activities will begin shortly after cessation of operations, which will occur when the operating licenses expire. We expect to decommission the Surry and North Anna units during the period 2032 to 2059. The license expiration dates for our units are shown in the following table:

(dollars in millions)	NRC license expiration year	Most recent cost estimate (2008 dollars)	Funds in trusts at December 31, 2008	2008 contributions to trusts
Surry				
Unit 1	**2032**	**$ 511**	**$ 296**	**$ 1.4**
Unit 2	**2033**	**540**	**292**	**1.5**
North Anna				
Unit 1	**2038**	**485**	**239**	**1.0**
Unit 2	**2040**	**507**	**226**	**0.9**
Total		**$ 2,043**	**$ 1,053**	**$ 4.8**

Corporate and Other

We also have a Corporate and Other segment that primarily includes specific items attributable to our operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments.

ENVIRONMENTAL STRATEGY

We are committed to being a good environmental steward. Our ongoing objective is to provide reliable, affordable energy for our customers while being environmentally responsible. Our integrated strategy to meet this objective consists of four major elements:

- Conservation and load management;
- Renewable generation development;
- Other generation development to maintain our fuel diversity, including clean coal, advanced nuclear energy, and natural gas; and
- Improvements in other energy infrastructure.

Conservation plays a role in meeting the growing demand for electricity. Virginia re-regulation legislation enacted in 2007 provides incentives for energy conservation and sets a goal to reduce electricity consumption by retail customers in 2022 by ten percent of the amount consumed in 2006 through the implementation of conservation programs. A description of our conservation and load management programs is detailed below.

We are working to improve our own energy efficiency, both in using less fuel to produce the same amount of energy and to use less energy in our operations. Recent uprates of our facilities have resulted in significant increases in generation capacity and a lower emitting fleet to meet the needs of our customers.

Renewable energy is also an important component of a diverse and reliable energy mix. Both Virginia and North Carolina have passed legislation setting targets for renewable power. We are committed to meeting Virginia s goal of 12% renewable power by 2022 and North Carolina s renewable portfolio standard of 12.5% by 2021.

We are actively assessing development opportunities in our service territories for renewable technologies. In November 2007, we issued a request for proposals (RFP) for renewable energy projects in Virginia, North Carolina or elsewhere in the PJM Interconnect region. The RFP seeks the purchase of renewable energy generation projects, as well as renewable energy credits. We currently provide approximately two percent of our generation from renewable sources. We also anticipate using at least 10% biomass (wood waste) at the Virginia City Hybrid Energy Center.

We have announced a comprehensive generation growth program, referred to as *Powering Virginia*, which involves the development, financing, construction and operation of new multi-fuel, multi-technology generation capacity to meet the growing demand in our core market of Virginia. We expect that these investments collectively will provide the following benefits: expanded electricity production capability; increased technological and fuel diversity; and a reduction in the carbon dioxide (CO_2) emission intensity of our generation fleet. A critical aspect of the *Powering Virginia* program is the extent to which we seek to reduce the carbon intensity of our generation fleet by developing generation facilities with zero CO_2 and low CO_2 emissions, as well as economically viable facilities that can be equipped for CO_2 capture and storage. There is no current economically viable technological solution to retro-fit existing fossil-fueled technology to capture and store greenhouse gas (GHG) emissions. Given that new generation units have useful lives of up to 55 years, we will give full consideration to CO_2 and other GHG emissions when making long-term decisions. See *Generation Properties* for more information on generation expansion projects.

Finally, we plan to make a significant investment in improving the capabilities and reliability of our electric transmission and distribution system. These enhancements are primarily aimed at meeting our continued goal of providing reliable service. An additional benefit will be added capacity to efficiently deliver electricity from the renewable projects now being developed or to be developed in the future. See also *Global Climate Change* under *Regulation* for additional information.

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Conservation and Load Management Programs

We have conducted a series of short-term pilot programs focused on energy conservation and demand response. The pilots were offered to a selection of 4,550 customers in our central, eastern and northern Virginia service areas. To help ensure that the results were representative, solicitations were given to select customers. No customer could participate in more than one pilot. We reported results from the pilots at least quarterly to the Virginia Commission staff to help evaluate their effectiveness. Most of these pilots had ended as of December 31, 2008.

The pilots approved by the Virginia Commission included:

- 1,000 residential customers in each of four different energy-saving pilots. The pilots were designed to cycle central air conditioning units during peak-energy demand times, inform customers about their real-time energy consumption patterns, promote programmable thermostats that allow customers to control their use of electricity, and educate customers about the value of reducing energy use during peak-use times.
- Free energy audits and energy efficiency kits to 150 existing residential customers, 100 new homes meeting energy efficiency guidelines set by the EPA, and 50 small commercial customers. In addition, 250 new customer accounts received energy efficiency welcome kits.
- Incentives for commercial customers to reduce load during periods of peak demand by running their generators to produce up to 100 Mw of electricity. This is in addition to existing Dominion options in which commercial and industrial customers have reduced demand by more than 300 Mw during peak-demand periods.

In June 2008, we announced an energy conservation and load management plan that, if implemented, is expected to produce long-term environmental benefits while providing customers with cost savings. The plan is part of our *Powering Virginia* strategy to meet the future needs of customers. We expect to launch the plan in early 2010, subject to approval by the Virginia Commission and the North Carolina Commission, as applicable.

A key component of the plan is the potential installation of smart grid technologies that are designed to enhance our electric distribution system by allowing energy to be delivered more efficiently. Dependent upon the outcome of demonstration projects taking place in 2009, we expect to make a significant investment in replacing all of our existing meters with Advanced Metering Infrastructure (AMI). The technology is expected to lead to improvements in service reliability and the ability of customers to monitor and control their energy use. Additionally, programs in the conservation plan include:

- Incentives for construction of energy-efficient homes that meet the federal government s Energy Star® standards;
- Incentives for residential and commercial customers to install energy-efficient lighting;
- Energy audits and improvements for homes of low-income customers;
- Incentives for residential customers who voluntarily enroll to allow the Company to cycle their air-conditioners and heat pumps during periods of peak demand;
- In-home display devices that display the amount and cost of electricity customers are using; and
- Incentives for residential and commercial customers to improve the energy efficiency of their heating and/or cooling units.

REGULATION

We are subject to regulation by the Virginia Commission, North Carolina Commission, SEC, FERC, EPA, DOE, NRC, Army Corps of Engineers and other federal, state and local authorities.

State Regulations

We are subject to regulation by the Virginia Commission and the North Carolina Commission. We hold certificates of public convenience and necessity which authorize us to maintain and operate our electric facilities now in operation and to sell electricity to customers. However, we 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 addition, the Virginia Commission and the North Carolina Commission regulate our transactions with other Dominion subsidiaries (affiliates), transfers of certain facilities and issuance of securities.

Status of Electric Regulation in Virginia

2007 Virginia Regulation Act and Fuel Factor Amendments

On July 1, 2007, legislation amending the Virginia Electric Utility Restructuring Act (the Regulation Act) and the fuel factor statute became effective, which significantly changed electricity regulation in Virginia. Prior to the Regulation Act, our base rates in Virginia were to be capped at 1999 levels until December 31, 2010, at which time Virginia was to convert to retail competition for its electric supply service. The Regulation Act ended capped rates two years early, on December 31, 2008, at which time retail competition would be available only to individual retail customers with a demand of more than 5 Mw and non-residential retail customers who obtain Virginia Commission approval to aggregate their load to reach the 5 Mw threshold. Individual retail customers will also be permitted to purchase renewable energy from competitive suppliers if their incumbent electric utility does not offer a 100% renewable energy tariff.

Pursuant to the Regulation Act, the Virginia Commission entered an order in January 2009 initiating reviews of the base rates and terms and conditions of all investor-owned utilities in Virginia. The Company must submit its filing and accompanying schedules on or before April 1, 2009, and it anticipates that its filing will support an increase in base rates. The ROE in that rate review will be no lower than that reported by not less than a majority of comparable utilities within the southeastern U.S., with certain limitations, as described in the Act. Possible outcomes of the 2009 rate review, according to the Regulation Act, include a rate increase, a rate decrease, and a refund of earnings more than 50 basis points above the authorized ROE. We are unable to predict the outcome of future rate actions at this time. However, an unfavorable outcome could adversely affect our results of operations, financial condition and cash flows.

After the 2009 rate review, the Virginia Commission will conduct biennial reviews of our rates, terms and conditions beginning in 2011. As in the 2009 rate review, our ROE in the biennial reviews can be no lower than that reported by not less than a majority of comparable utilities within the southeastern U.S., with certain limitations, as described in the Act. The Commission shall be authorized to increase our base rates if our earnings are more than 50 basis points below the authorized level. If our earnings are more than 50 basis points above the authorized level, such earnings will be shared with customers. If over-earning persists for two consecutive biennial periods, in addition to earnings sharing, rates may also be reduced.

Separate from base rates, the Regulation Act also authorizes stand-alone rate adjustment clauses for recovery of costs for new generation projects, environmental compliance, FERC-approved transmission costs, conservation and energy efficiency programs, and renewables programs. The Act also provided for enhanced returns on capital expenditures on specific new generation projects, including but not limited to nuclear generation, clean coal/carbon capture compatible generation, and renewable generation projects.

The Regulation Act also continues statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter, as discussed in *Virginia Fuel Expenses*.

Virginia Fuel Expenses

Under amendments to the Virginia fuel cost recovery statute passed in 2004, our fuel factor provisions were frozen until July 1, 2007. Fuel prices increased considerably during that period, which resulted in our fuel expenses being significantly in excess of our fuel cost recovery. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were re-instituted beginning July 1, 2007. While the 2007 amendments did not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor was adjusted, this mechanism ensures dollar-for-dollar recovery for prudently incurred fuel costs.

In April 2007, we filed a Virginia fuel factor application with the Virginia Commission. The application showed a need for an annual increase in fuel expense recovery for the period July 1, 2007 through June 30, 2008 of approximately $662 million; however, the requested increase was limited to $219 million under the 2007 amendments to the fuel cost recovery statute, which limited the increase to an amount that resulted in the residential customer class not receiving an increase of more than 4% of total rates in effect as of June 30, 2007. The Virginia Commission approved a fuel factor increase for Virginia jurisdictional customers of approximately $219 million, effective July 1, 2007, with the balance of approximately $443 million deferred for subsequent recovery subject to Virginia Commission approval, without interest, during the period commencing July 1, 2008 and ending June 30, 2011.

In May 2008, we filed an application to revise our fuel factor with the Virginia Commission that would have resulted in an annual increase from 2.232 cents per kWh to 4.245 cents per kWh, effective July 1, 2008. This revised factor included $231 million of prior year under-recovered fuel expense out of a total estimated prior year under-recovered balance of $697 million with the remaining deferred fuel balance expected to be recovered over the next two fuel rate years beginning July 1, 2009. As part of the application, we proposed adoption of a rule that would limit the fuel factor to 3.893 cents per kWh for the current fuel period of July 1, 2008 through June 30, 2009. In order to achieve this lower fuel factor increase, the proposal would have delayed recovery of the prior year under-recovered fuel balance of $697 million to be collected over a three-year period beginning July 1, 2009.

The Virginia Commission approved a settlement proposed by us and other parties, which provided for the following, effective July 1, 2008:

- i) an increase of our fuel tariff to 3.893 cents per kWh for the collection of the current period and partial recovery of the prior year under-recovered fuel balance;
- ii) the recovery of $231 million of the approximately $697 million prior year under-recovered fuel balance, with the balance to be recovered in subsequent fuel periods as provided by Virginia law;
- iii) the fuel tariff of 3.893 cents per kWh is estimated to result in an under-recovery of $231 million of projected fuel expenses during the current period; and
- iv) we will not propose to recover a return or interest or any other form of carrying costs on the balance of uncollected fuel expenses described in subsection (ii) above, including the estimated $231 million under-recovery of current period expenses described in subsection (iii), provided that the total amount on which we will not propose to recover interest or any other form of carrying costs is limited to $697 million.

The resulting increase in a 1,000 kWh Virginia jurisdictional residential customer s monthly bill is approximately 18% for the 2008 through 2009 fuel period.

North Carolina Regulation

In 2004, the North Carolina Commission commenced a review of our North Carolina base rates and subsequently ordered us to file a general rate case to show cause why our North Carolina jurisdictional base rates should not be reduced. The rate case was filed in September 2004, and in March 2005 the North Carolina Commission approved a settlement that included a prospective $12 million annual reduction in current base rates and a five-year base rate moratorium, effective as of April 2005. Fuel rates are still subject to annual fuel rate adjustments, with deferred fuel accounting for over- and under-recoveries of fuel costs.

In September 2008, we filed an application to revise our fuel factor with the North Carolina Commission, requesting an annual increase in our North Carolina fuel factor from 2.221 cents per kWh to 3.825 cents per kWh to be effective January 1, 2009. The proposal would result in an annual increase in fuel revenue of approximately $69 million for the North Carolina jurisdiction. In December 2008, the Company, the Public Staff of the North Carolina Commission and other parties filed a proposed settlement that would increase our North Carolina fuel factor from 2.221 cents per kWh to 3.206 cents per kWh. The North Carolina Commission approved the settlement in December 2008. The resulting increase in annual fuel revenue is approximately $42 million for the North Carolina jurisdiction.

Federal Regulations

Federal Energy Regulatory Commission

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. We sell electricity in the PJM wholesale market under our market-based sales tariffs authorized by FERC. In addition, we have FERC approval of a tariff to sell wholesale power at capped rates based on our embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside our service territory. Any such sales would be voluntary. In May 2005, FERC issued an order finding that PJM s existing

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transmission service rate design may not be just and reasonable, and ordered an investigation and hearings on the matter. In January 2008, FERC affirmed its earlier decision that the PJM transmission rate design for existing facilities had not become unjust and unreasonable. For recovery of costs of investments of new PJM-planned transmission facilities that operate at or above 500 kV, FERC established a regional rate design where all customers pay a uniform rate based on the costs of such investment. For recovery of costs of investment in new PJM-planned transmission facilities that operate below 500 kV, FERC affirmed its earlier decision to allocate costs on a beneficiary pays approach. A notice of appeal of this decision was filed in February 2008 at the United States Court of Appeals for the Seventh Circuit and the appeal is pending. We cannot predict the outcome of the appeal.

We are subject to FERC s Standards of Conduct that govern conduct between the transmission function employees interstate gas and electricity transmission providers and the marketing function employees of their affiliates. The rule defines the scope of transmission and marketing-related functions that are covered by the standards and is designed to prevent transmission providers from giving their affiliates undue preferences. We are also subject to FERC s affiliate restrictions that (1) prohibit power sales between us and Dominion s merchant plants without first receiving FERC authorization, (2) require us and Dominion s merchant plants to conduct our wholesale power sales operations separately, and (3) prohibit us from sharing market information with Dominion s merchant plant operating personnel. The rules are designed to prohibit us from giving Dominion s merchant plants a competitive advantage.

EPACT included provisions to create an Electric Reliability Organization (ERO). The ERO is required to promulgate mandatory reliability standards governing the operation of the bulk power system in the U.S. In 2006, FERC certified NERC as the ERO beginning on January 1, 2007. In late 2006, FERC also issued an initial order approving many reliability standards that went into effect on January 1, 2007. Beginning in June 2007, entities that violate standards will be subject to fines of between $1 thousand and $1 million per day, and can also be assessed non-monetary penalties, depending upon the nature and severity of the violation.

We have planned and operated our facilities in compliance with earlier NERC voluntary standards for many years and are fully aware of the new requirements. We participate on various NERC committees, track development and implementation of standards, and maintain proper compliance registration with NERC s regional organizations. While we expect that there will be some additional cost involved in maintaining compliance as standards evolve, we do not expect the expenditures to be significant.

In April 2008, FERC granted an application by our electric transmission operations to establish a forward-looking formula rate mechanism that will update transmission rates on an annual basis and approved an ROE of 11.4% on the common equity base of these operations, effective as of January 1, 2008. The formula rate is designed to cover the expected cost of service for each calendar year and will be trued up based on actual costs. While other transmission owners in the PJM region use a formula rate based on historic costs, our formula rate is based on projected

costs. The FERC ruling did not materially impact our results of operations; however, going forward the FERC-approved formula method will allow us to earn a more current return on our growing investment in electric transmission infrastructure.

In July 2008, we filed an application with FERC requesting a revision to our cost of service to reflect an additional ROE incentive adder for eleven electric transmission enhancement projects. Under the proposal, our cost of transmission service would increase to include an ROE incentive adder for each of the eleven projects, beginning the date each project enters commercial operation (but not before January 1, 2009). We proposed an incentive of 150 basis points or 1.5% for four of the projects (including the Meadow Brook-to-Loudoun line and Carson-to-Suffolk line) and an incentive of 125 basis points or 1.25% for the other seven projects. In August 2008, FERC approved our proposal, effective September 1, 2008. The total cost for all eleven projects is estimated at $877 million, and all projects are currently expected to be completed by 2012. Numerous parties sought rehearing of the FERC order in August 2008 and rehearing is pending. We cannot predict the outcome of the rehearing.

In May 2008, the Maryland Public Service Commission, Delaware Public Service Commission, Pennsylvania Commission, New Jersey Board of Public Utilities, the American Forest & Paper Association, the Portland Cement Association and several other organizations representing consumers in the PJM region (the RPM Buyers) filed a complaint at FERC claiming that PJM s Reliability Pricing Model s transitional auctions have produced unjust and unreasonable capacity prices. The RPM Buyers requested that a refund effective date of June 1, 2008 be established and that FERC provide appropriate relief from unjust and unreasonable capacity charges within 15 months. In September 2008, FERC dismissed the complaint. The RPM Buyers requested rehearing of the FERC order in October 2008 and rehearing is pending. We cannot predict the outcome of the rehearing.

In September 2008, we and Dominion filed a Deferral Recovery Charge (DRC) request with FERC to recover approximately $153 million of RTO costs ($140 million of our costs and $13 million of Dominion s costs) that we have been unable to recover due to a statutory base rate cap established under Virginia law. The RTO costs include:

(i) costs for development of the Alliance RTO on and after this base rate cap became effective on July 1, 1999;
(ii) costs to start up our participation in PJM; and
(iii) PJM administrative fees billed by PJM from the date that we joined PJM as a transmission owner.

In December 2008, FERC approved the DRC to become effective January 1, 2009, as requested. However, recovery of RTO costs through the DRC will not commence until the date established by the Virginia Commission that permits us to implement such recovery. In January 2009, requests for rehearing of the DRC by FERC were filed by the Virginia Commission and the Virginia Attorney General s office. We cannot predict the outcome of the rehearing.

Environmental Regulations

General

Both of our operating segments face substantial laws, regulations and compliance costs with respect to environmental matters. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. If our expenditures for pollution control technologies and associated operating costs are not recoverable from customers through regulated rates, those costs could adversely affect future results of operations and cash flows. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the Company. We have applied for or obtained the necessary environmental permits for the operation of our facilities. Many of these permits are subject to reissuance and continuing review. For a discussion of significant aspects of these matters, including current and planned capital expenditures relating to environmental compliance, see *Environmental Matters* in *Future Issues and Other Matters* in MD&A. Additional information can also be found in Item 3. Legal Proceedings and Note 20 to our Consolidated Financial Statements.

Air

The Clean Air Act (CAA) is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation s air quality. At a minimum, states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of our facilities are subject to the CAA s permitting and other requirements.

In March 2005, the EPA Administrator signed both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules, if implemented, would require significant reductions in SO_2, nitrogen oxide (NO_X) and mercury emissions from electric generating facilities.

In February 2008, the D.C. Appeals Court issued a ruling that vacates CAMR as promulgated by the EPA. In May 2008, the EPA s appeal of this decision with the D.C. Appeals Court was denied. In September 2008, the Utility Air Regulatory Group filed a petition requesting that the U.S. Supreme Court review the D.C. Appeals Court decision to vacate the EPA rule. In October 2008, the Solicitor General, on behalf of the EPA, also filed a petition with the U.S. Supreme Court; however, in February 2009, it filed a motion to dismiss its petition. Also in February 2009 the U.S. Supreme Court denied the Utility Air Regulatory Group s petition. The EPA Administrator has announced that the EPA will proceed with a Maximum Achievable Control Technology rule-making. We cannot predict how the EPA or the states may alter their approach to reducing mercury emissions.

In July 2008, the D.C. Appeals Court issued a ruling vacating CAIR as promulgated by the EPA. A number of parties, including the EPA, filed petitions for a rehearing of the decision. The Court s decision resulted in a decline in the market value of SO_2 allowances that could have limited our ability to monetize the value of these allowances in the future. During the third quarter of 2008, we tested our SO_2 allowances for impairment and concluded that no impairment adjustment was required as a result of this decline in market value. In December 2008, the Court denied rehearing, but also issued a decision to remand CAIR to the EPA, so the CAIR rules remain in effect. The remand resulted in an increase in the market value of SO_2 allowances and allows CAIR to remain in place until such time that the EPA develops and implements a new rulemaking addressing the issues identified by the Court. We cannot predict how a new rulemaking will

impact future SO_2 and NO_X emission reduction requirements beyond CAIR.

In June 2005, the EPA finalized amendments to the Regional Haze Rule, also known as the Clean Air Visibility Rule (CAVR). Although we anticipate that the emission reductions achieved through compliance with other CAA required programs will generally address CAVR if those rules proceed, additional emission reduction requirements may be imposed on our facilities.

Implementation of projects to comply with SO_2, NO_X and mercury limitations, and other state emission control programs are ongoing and will be influenced by changes in the regulatory environment, availability of emission allowances and emission control technology. In response to these requirements, we estimate that we will make capital expenditures at our affected generating facilities of approximately $260 million during the period 2009 through 2013.

Water

The Clean Water Act (CWA) is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. We must comply with all aspects of the CWA programs at our operating facilities. In July 2004, the EPA published regulations under CWA Section 316b that govern existing utilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold. The EPA s rule presented several compliance options. However, in January 2007, the U.S. Court of Appeals for the Second Circuit issued a decision on an appeal of the regulations, remanding the rule to the

EPA. In July 2007, the EPA suspended the regulations pending further rulemaking, consistent with the decision issued by the U.S. Court of Appeals for the Second Circuit. In November 2007, a number of industries appealed the lower court decision to the U.S. Supreme Court. In April 2008, the U.S. Supreme Court granted the industry request to review the question of whether Section 316b of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Oral arguments were presented before the U.S. Supreme Court in December 2008 with a decision expected in 2009. We have eight facilities that are likely to be subject to these regulations. We cannot predict the outcome of the judicial or EPA regulatory processes, nor can we determine with any certainty what specific controls may be required.

Solid and Hazardous Waste

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), provides for an immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. government either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at certain sites. These potentially responsible parties (PRPs) can be ordered to perform a cleanup, be sued for costs associated with an EPA-directed cleanup, voluntarily settle with the U.S. Government concerning their liability for cleanup costs, or voluntarily begin a site investigation and site remediation under state oversight.

From time to time, we may be identified as a PRP to a Superfund site. Refer to Note 20 to our Consolidated Financial Statements for a description of our exposure relating to our identification as a PRP. We do not believe that any currently identified sites will result in significant liabilities.

Global Climate Change

General

In recent years there has been increased national and international attention to GHG emissions and their relationship to climate change. We expect that there will be federal, regional or state legislative or regulatory action in this area in the near future. Dominion supports national climate change legislation to provide a consistent, economy-wide approach to addressing this issue and is taking action to protect the environment and address climate change while meeting the future needs of its growing service territory.

For Generation, our direct CO_2 emissions, based on ownership, were approximately 35 million metric tonnes in 2007. While we do not have final 2008 emissions data for Generation, we estimate that there will not be a significant variance in emissions from 2007 amounts. The emissions reported are for CO_2 directly emitted to the atmosphere based on the combustion of carbon-based fuels. Direct CO_2 emissions are provided based on emissions from primary stack and emissions from any auxiliary combustion equipment located at the electric generation facility. Primary facility stack emissions of CO_2 from carbon-based fuel combustion are directly measured via methods set forth under 40 CFR Part 75 of the United States Code (USC). For those emission sources not covered under 40 CFR Part 75 requirements, quantification is based on fuel combustion and emission factors consistent with industry best practices.

Climate Change Legislation

The new presidential administration and Congress bring expanded support for federal legislative action and regulatory initiatives for mandatory GHG emission reductions. The new presidential administration is expected to offer comprehensive legislation to establish an economy-wide program to significantly reduce GHG emissions. Other legislative efforts may propose reduction requirements measured against current emission levels. These proposals will possibly include some emission allowances allocated to major sectors of the economy covered by the legislation with a remaining amount of allowances auctioned to interested parties, both covered and non-covered sectors of the economy. Climate change legislation continues to evolve and accordingly, we cannot predict what, if any, legislation will ultimately pass.

In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG emissions, which could result in future EPA action. Possible outcomes from this decision include regulation of GHG emissions from various sources, including electric generation.

We currently support the enactment of federal legislation that regulates GHG emissions economy-wide, establishes a system of tradable allowances, slows the growth of GHG emissions in the near term and reduces GHG emissions in the long term. In addition, we support legislation that sets a realistic baseline year and

schedule and that is designed in a way to limit potential harm to the economy and competitive businesses.

In addition to possible federal action, some regions and states in which we operate have already or may adopt GHG emission reduction programs. For example, the Virginia Energy Plan, released by the Governor of Virginia in September 2007, includes a goal of reducing GHG emissions statewide back to 2000 levels by 2025. The Governor formed a Commission on Climate Change to develop a plan to achieve this goal. In November 2008, the Commission on Climate Change formulated their recommendations to the Governor.

The United States is currently not a party to the Kyoto Protocol, which is a protocol to the United Nations Framework Convention on Climate Change and became effective for signatories on February 16, 2005. The Kyoto Protocol process generally requires developed countries to cap GHG emissions at certain levels during the 2008-2012 time period. At the conclusion of the December 2007 United Nations Climate Change Conference in Bali, Indonesia, the Bali Action Plan was adopted which identifies a timeline for the consideration of possible post-2012 international actions to further address climate change. The U.S. is expected to participate in this process.

The cost of compliance with future GHG emission reduction programs could be significant. Given the highly uncertain outcome and timing of future action by the U.S. federal government and states on this issue, we cannot predict the financial impact of future GHG emission reduction programs on our operations or our customers at this time.

Dominion s Strategy for Voluntarily Reducing CO_2 Emissions

While Dominion has not established a stand alone CO_2 emissions reduction target or timetable, we are actively engaged in voluntary reduction efforts and will work toward achieving the standards established by existing state regulations as set forth above. We have an integrated strategy for reducing CO_2 emission intensity that is based on maintaining a diverse fuel mix, including nuclear, coal, gas, hydro and renewable energy, investing in renewable energy projects, and promoting energy conservation and efficiency efforts. See *Environmental Strategy* above for a description of our strategy for reducing CO_2 emission intensity. Some recent efforts that have or are expected to reduce the Company s carbon intensity include:

- In 2003, we retired two oil-fired units at our Possum Point Power Station, replacing them with a new 559 Mw combined cycle natural gas technology. We also converted two coal-fired units to cleaner burning natural gas.
- Since 2000, we have added approximately 1,300 Mw of new lower-emitting natural gas-fired generation (excluding Possum Point) to our generation mix.
- We have also added 83 Mw of renewable biomass.
- In January 2009, we announced a joint effort with BP to evaluate wind energy projects in Tazewell County and Wise County, Virginia.
- In December 2007, we announced that we had acquired a 590-Mw combined-cycle natural gas-fired development project in Buckingham County, Virginia (Bear Garden).
- We have received an early site permit from the NRC for the possible addition of approximately 1,500 Mw of nuclear generation in Virginia.

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While, upon entering service, our new Virginia City Hybrid Energy Center which is currently under construction in Southwest Virginia will be a new source of GHG emissions, we have taken steps to minimize the impact on the environment. The new plant is expected to use at least ten percent biomass for fuel and was designed to be carbon-capture compatible, meaning that technology to capture CO_2 can be added to the station when it becomes commercially available. Also, we have announced plans to convert our coal units at Bremo Power Station to natural gas, contingent upon the Virginia City Hybrid Energy Center entering service and receipt of necessary approvals. See *Generation-Properties* for more information on the projects above, as well as other projects under current development.

Since 2000, we have tracked the emissions of our electric generation fleet. Our electric generation fleet employs a mix of fuel and renewable energy sources. Comparing annual year 2000 to annual year 2007, our electric generating fleet (based on our ownership percentage) reduced its average CO_2 emissions rate per megawatt- hour of energy produced from electric generation by about 3.5%. During such time period the capacity of our electric generation fleet has grown.

Nuclear Regulatory Commission

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

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 our nuclear generating units.

The NRC also requires us to decontaminate our nuclear facilities once operations cease. This process is referred to as decommissioning, and we are required by the NRC to be financially prepared. For information on our decommissioning trusts, see *Generation Nuclear Decommissioning* and Note 8 to our Consolidated Financial Statements.

Spent Nuclear Fuel

Under provisions of the Nuclear Waste Policy Act of 1982, we have entered into a contract with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by our contract with the DOE. In January 2004, we filed a lawsuit in the U.S. Court of Federal Claims against the DOE requesting damages in connection with its failure to commence accepting spent nuclear fuel. A trial occurred in May 2008 and post-trial briefing and argument concluded in July 2008. On October 15, 2008, the Court issued an opinion and order for us in the amount of approximately $112 million for our spent fuel-related costs through June 30, 2006, and judgment was entered by the Court on October 28, 2008. On December 24, 2008, the government appealed the judgment to the U. S. Court of Appeals for the Federal Circuit and the appeal was docketed on December 30, 2008. Briefing on the appeal is expected to take

place in 2009. Payment of any damages will not occur until the appeal process has been resolved. We cannot predict the outcome of this matter; however, in the event that we recover damages, such recovery, including amounts attributable to joint owners, is not expected to have a material impact on our results of operations. We will continue to manage our spent fuel until it is accepted by the DOE.

Item 1A. Risk Factors

Our business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond our control. We have identified a number of these factors below. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements* in MD&A.

Our 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 and winter storms, can be destructive, causing outages and property damage that require us to incur additional expenses. Additionally, droughts can result in reduced water-levels that could adversely affect operations at some of our power stations.

We are subject to complex governmental regulation that could adversely affect our operations. Our operations are subject to extensive federal, state and local regulation and require numerous permits, approvals and certificates from various governmental agencies. We must also comply with environmental legislation and associated regulations. Management believes that the necessary approvals have been obtained for our existing operations and that our business is conducted in accordance with applicable laws. However, new laws or regulations, the revision or reinterpretation of existing laws or regulations, or penalties imposed for non-compliance with existing laws or regulations may require us to incur additional expenses.

We could be subject to penalties as a result of mandatory reliability standards. As a result of EPACT, owners and operators of bulk power transmission systems, including the Company, are subject to mandatory reliability standards enacted by NERC and enforced by FERC. If we are found not to be in compliance with the mandatory reliability standards we could be subject to sanctions, including substantial monetary penalties.

Our costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws could adversely affect our cash flow and profitability. Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources, and health and safety. Compliance with these legal requirements requires us to commit significant capital toward permitting, emission fees, environmental monitoring, installation and operation of pollution control equipment and purchase of allowances and/or offsets. Additionally, we could be responsible for expenses relating to remediation and containment obligations, including at sites where we have been identified by a regulatory agency as a PRP. Our expenditures relating to environmental compliance have been significant in the past, and we expect that they will remain significant in the future. Costs of compliance with environmental regulations could adversely affect our results of operations and financial condition, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increases. We cannot estimate our compliance costs with certainty due to our inability to predict the requirements and timing of implementation of any new environmental rules or regulations related to emissions. Other factors which affect our ability to predict our future environmental expenditures with certainty include the difficulty in estimating clean-up costs and quantifying liabilities under environmental laws that impose joint and several liability on all responsible parties.

If federal and/or state requirements are imposed on energy companies mandating further emission reductions, including limitations on CO_2 emissions, such requirements could make some of our electric generating units uneconomical to maintain or operate. Environmental advocacy groups, other organizations and some agencies are focusing considerable attention on CO_2 emissions from power generation facilities and their potential role in climate change. We expect that federal legislation, and possibly additional state legislation, may pass resulting in the imposition of limitations on GHG emissions from fossil fuel-fired electric generating units. Such limits could make certain of our electric generating units uneconomical to operate in the long term, unless there is significant advancement in the commercial availability and cost of carbon capture and storage technology. In addition, a number of bills have been introduced in Congress that would require GHG emission reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none have yet been enacted. Compliance with these GHG emission reduction requirements may require us to commit significant capital toward carbon capture and storage technology, purchase of allowances and/or offsets, fuel switching, and/or retirement of high-emitting generation facilities and potential replacement with lower emitting generation facilities. The cost of compliance with expected GHG emission legislation is subject to significant uncertainties due to the outcome of several interrelated assumptions and variables, including timing of the implementation of rules, required levels of reductions, allocation requirements of the new rules, the maturation and commercialization of carbon capture and storage technology and associated regulations, and our selected compliance alternatives. As a result, we cannot estimate the effect of any such legislation on our results of operations, financial condition, or our customers.

Our base rates are subject to regulatory review. As a result of the Regulation Act, commencing in 2009, our base rates will be reviewed by the Virginia Commission under a modified cost-of-service model. Such rates will be set based on analyses of our costs and capital structure, as reviewed and approved in regulatory proceedings. Under the Regulation Act, the Virginia Commission may, in a proceeding conducted in 2009, reduce rates or order a credit to customers if we are deemed to be earning more than 50 basis points above an ROE level to be established by the Virginia Commission in that proceeding. After the initial rate case, the Virginia Commission will review our base rates biennially and may order a credit to customers if we are deemed to have earned an ROE more than 50 basis points above an ROE level established by the Virginia Commission and may reduce rates if we are found to have had earnings in excess of the established ROE level during two consecutive biennial review periods.

Delays in the recovery of fuel costs could negatively affect our cash flow, which could adversely affect our results of operations. We have a statutory right to recover from customers all prudently incurred fuel costs through fuel factors which have been implemented in our Virginia and North Carolina jurisdictions. However, as a result of increasing fuel costs and a statutory limitation on the amount of fuel recovery that could be collected from Virginia jurisdictional customers in the July 1, 2007 through June 30, 2008 fuel factor period, we have deferred a significant amount of fuel costs. Deferred recovery of fuel costs could have a negative impact on our cash flow. The recent fluctuations in fuel prices may make it difficult to accurately predict fuel costs. In the future, if actual fuel costs incurred during the fuel factor period exceed the estimate of costs which the Virginia Commission has approved for recovery in that period, we will not have authority to recover the excess costs through fuel rates until the following year when a new factor is determined. To the extent that such deferrals occur, the resulting delays in the current recovery of fuel costs could negatively impact our cash flow, which could adversely affect our results of operations.

The rates of our electric transmission operations are subject to regulatory review. Revenue provided by our electric transmission operations is based primarily on rates approved by FERC. The profitability of this businesses is dependent on our ability, through the rates that we are permitted to charge, to recover costs and earn a reasonable rate of return on our capital investment. Our wholesale charges for electric transmission service are adjusted on an annual basis through operation of a FERC-approved formula rate mechanism. Through this mechanism our wholesale electric transmission cost of service is estimated and thereafter trued-up as appropriate to reflect actual costs allocated to the Company by PJM. These wholesale rates are subject to FERC review and prospective adjustment in the event that customers and/or interested state commissions file a complaint with FERC and are able to demonstrate that our wholesale revenue requirement is no longer just and reasonable.

Energy conservation could negatively impact our financial results. Certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce energy consumption by a fixed date. To the extent conservation resulted in reduced energy demand or significantly slowed the growth in demand, it could negatively impact us depending on the regulatory treatment of the associated impacts. Should we be required to invest in conservation measures that resulted in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. We are unable to determine what impact, if any, conservation will have on our financial condition or results of operations.

Our operations could be affected by terrorist activities and catastrophic events that could result from terrorism. In the event that our generating facilities or other infrastructure assets are subject to potential terrorist activities, such activities could significantly impair our operations and result in a decrease in revenues and additional costs to repair and insure our assets, which could have a material adverse effect on our business. The effects of potential terrorist activities could also include the risk of a significant decline in the U.S. economy, and the decreased availability and increased cost of insurance coverage, any of which effects could negatively impact our operations and financial condition.

We have incurred increased capital and operating expenses and may incur further costs for enhanced security in response to such risks.

There are risks associated with the operation of nuclear facilities. We operate nuclear facilities that are subject to risks, including our 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 our ability to maintain adequate reserves for decommissioning, costs of replacement power, costs of plant maintenance and exposure to potential liabilities arising out of the operation of these facilities. We maintain decommissioning trusts and external insurance coverage to mitigate the financial exposure to these risks. However, it is possible that decommissioning costs could exceed the amounts in our trusts or that costs arising from claims could exceed the amount of any insurance coverage.

The use of derivative instruments could result in financial losses and liquidity constraints. We use derivative instruments, including futures, swaps, forwards, options and financial transmission rights (FTRs) to manage the commodity and financial market risks of our business operations. We 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 contracts 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 reported fair value of these contracts.

Derivatives designated under hedge accounting to the extent not fully offset by the hedged transaction can result in ineffectiveness losses. These losses primarily result from differences in the location and specifications of the derivative hedging instrument and the hedged item and could adversely affect our results of operations.

Our operations in regards to these transactions are subject to multiple market risks including market liquidity, counterparty credit strength and price volatility. These market risks are beyond our control and could adversely affect our results of operations and future growth.

For additional information concerning derivatives and commodity-based contracts, see *Market Risk Sensitive Instruments and Risk Management* in Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Notes 2 and 7 to our Consolidated Financial Statements.

We may not complete plant construction or expansion projects that we commence, or we may complete projects on materially different terms or timing than initially anticipated and we may not be able to achieve the intended benefits of any such project, if completed. We have announced several plant construction and expansion projects and may consider additional projects in the future. We anticipate that we will be required to seek additional financing in the future to fund our current and future plant construction and expansion projects and we may not be able to secure such financing on favorable terms. In addition, we may not be able to complete the projects on time as a result of weather conditions, delays in obtaining or failure to obtain regulatory approvals, delays in obtaining key materials, labor difficulties, difficulties with partners or potential partners, a decline in the credit strength of our

counterparties or vendors, or other factors beyond our control. Even if plant construction and expansion projects are completed, the total costs of the projects may be higher than anticipated and the performance of our business following the projects may not meet expectations. Additionally, regulators may disallow recovery of some of the costs of a project if they are deemed not to be prudently incurred. Further, we may not be able to timely and effectively integrate the projects into our operations and such integration may result in unforeseen operating difficulties or unanticipated costs. Any of these or other factors could adversely affect our ability to realize the anticipated benefits from the plant construction and expansion projects.

An inability to access financial markets could affect the execution of our business plan. We rely on access to short-term money markets, longer-term capital markets and banks as significant sources of funding and liquidity for capital expenditures and normal working capital. Management believes that we will maintain sufficient access to these financial markets based upon our current credit ratings and market reputation. However, certain disruptions outside of our control may increase our cost of borrowing or restrict our ability to access one or more financial markets. Such disruptions could include a continuation of the current economic downturn, the bankruptcy of an unrelated company, general market disruption due to general credit market or political events, changes to our credit ratings or the failure of financial institutions on which we rely. Restrictions on our ability to access financial markets may affect our ability to execute our business plan as scheduled.

Changing rating agency requirements could negatively affect our growth and business strategy. As of February 1, 2009, our senior unsecured debt is rated A-, stable outlook, by Standard & Poor s Ratings Services, a division of the McGraw-Hill Companies, Inc. (Standard & Poor s); Baa1, stable outlook, by Moody s Investors Service (Moody s); and A-, stable outlook, by Fitch Ratings Ltd. (Fitch). In order to maintain our current credit ratings in light of existing or future requirements, we may find it necessary to take steps or change our business plans in ways that may adversely affect our growth and earnings. A reduction in our credit ratings by Standard & Poor s, Moody s or Fitch could increase our borrowing costs and adversely affect operating results.

Potential changes in accounting practices may adversely affect our financial results. We cannot predict the impact that future changes in accounting standards or practices may have on public companies in general, the energy industry or our operations specifically. New accounting standards could be issued that could change the way we record revenues, expenses, assets and liabilities. These changes in accounting standards could adversely affect our reported earnings or could increase reported liabilities.

Failure to retain and attract key executive officers and other skilled professional and technical employees could have an adverse effect on our operations. Our business strategy is dependent on our ability to recruit, retain and motivate employees. Competition for skilled employees in some areas is high and the inability to retain and attract these employees could adversely affect our business and future operating results.

Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

We own our principal properties in fee (except as indicated below), subject to defects and encumbrances that do not interfere materially with their use. Substantially all of our property is subject to the lien of the Indenture of Mortgage securing any of our First and Refunding Mortgage Bonds. There were no bonds outstanding as of December 31, 2008, however; by leaving the indenture open we retain the flexibility to issue mortgage bonds in the future.

We share our principal office in Richmond, Virginia, which is owned by our parent company, Dominion. In addition, our DVP and Generation segments share certain leased buildings and equipment. See Item 1. Business for additional information about each segment s principal properties.

Power Generation

Our Generation segment provides electricity for use on a wholesale and a retail level. Our Generation segment supplies electricity demand either from our generation facilities in Virginia, North Carolina and West Virginia or through purchased power contracts.

The following table lists our Generation segment s generating units and capability, as of December 31, 2008:

Plant	Location	Net Summer Capability (Mw)	Percentage Net Summer Capability
Coal			
Mt. Storm	Mt. Storm, WV	1,560	
Chesterfield	Chester, VA	1,235	
Chesapeake	Chesapeake, VA	595	
Clover	Clover, VA	433(a)	
Yorktown	Yorktown, VA	323	
Bremo	Bremo Bluff, VA	227	
Mecklenburg	Clarksville, VA	138	
North Branch	Bayard, WV	74	
Altavista	Altavista, VA	63	
Polyester(b)	Hopewell, VA	63	
Southampton	Southampton, VA	63	
Total Coal		4,774	26%
Gas			
Ladysmith (CT)	Ladysmith, VA	623	
Remington (CT)	Remington, VA	608	
Possum Point (CC)	Dumfries, VA	559	
Chesterfield (CC)	Chester, VA	397	
Elizabeth River (CT)	Chesapeake, VA	348	
Possum Point	Dumfries, VA	316	
Bellemeade (CC)	Richmond, VA	245	
Gordonsville Energy (CC)	Gordonsville, VA	218	
Darbytown (CT)	Richmond, VA	168	
Rosemary (CC)	Roanoke Rapids, NC	165	
Gravel Neck (CT)	Surry, VA	158	

Total Gas		3,805	21
Nuclear			
Surry	Surry, VA	1,598	
North Anna	Mineral, VA	1,596(c)	
Total Nuclear		3,194	18
Oil			
Yorktown	Yorktown, VA	818	
Possum Point	Dumfries, VA	786	
Gravel Neck (CT)	Surry, VA	186	
Darbytown (CT)	Richmond, VA	168	
Chesapeake (CT)	Chesapeake, VA	115	
Possum Point (CT)	Dumfries, VA	72	
Low Moor (CT)	Covington, VA	48	
Northern Neck (CT)	Lively, VA	47	
Kitty Hawk (CT)	Kitty Hawk, NC	31	
Total Oil		2,271	13

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Plant	Location		Net Summer Capability (Mw)	Percentage Net Summer Capability
Hydro				
Bath County	Warm Springs, VA		1,754(d)	
Gaston	Roanoke Rapids, NC		220	
Roanoke Rapids	Roanoke Rapids, NC		95	
Other	Various		3	
Total Hydro			2,072	11
Biomass				
Pittsylvania	Hurt, VA		83	1
Various				
Other	Various		11	---
			16,210	
Power Purchase Agreements			1,860	10
		Total Capability	18,070	100%

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

(a) Excludes 50% undivided interest owned by ODEC.
(b) Previously referred to as Hopewell.
(c) Excludes 11.6% undivided interest owned by ODEC.
(d) Excludes 40% undivided interest owned by Allegheny Generating Company, a subsidiary of Allegheny Energy, Inc.

Item 3. Legal Proceedings

From time to time, we are alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans imposed upon or agreed to by us, or permits issued by various local, state and federal agencies for the construction or operation of facilities. Administrative proceedings may also be pending on these matters. In addition, in the ordinary course of business, we are involved in various legal proceedings. We believe that the ultimate resolution of these proceedings will not have a material adverse effect on our financial position, liquidity or results of operations.

See *DVP, Generation* and *Regulation* in Item 1. Business, *Future Issues and Other Matters* in MD&A and Note 20 to our Consolidated Financial Statements for additional information on various environmental, rate matters and other regulatory proceedings to which we are a party.

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

None.

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Part II

Item 5. Market for the Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Dominion owns all of our common stock. Restrictions on our payment of dividends are discussed in *Dividend Restrictions* in Item 7. MD&A and Note 18 to our Consolidated Financial Statements. We paid quarterly cash dividends on our common stock as follows:

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
2008	**$ 115**	**$ 83**	**$ 163**	**$ 80**	**$ 441**
2007	77	65	196	39	377

Item 6. Selected Financial Data

Year Ended December 31, (millions)	**2008**	2007	2006	2005(1)	2004(2)
Operating revenue	**$ 6,934**	$ 6,181	$ 5,603	$ 5,712	$ 5,371
Income from operations before extraordinary item and cumulative effect of changes in accounting principles	**864**	606	478	485	590
Loss from discontinued operations, net of tax(3)				(471)	(159)
Extraordinary item, net of tax(4)		(158)			
Cumulative effect of changes in accounting principles, net of tax				(4)	
Net income	**864**	448	478	10	431
Balance available for common stock	**847**	432	462	(6)	415
Total assets	**18,802**	17,063	15,683	15,449	17,334
Long-term debt	**6,000**	5,316	3,619	3,888	4,958

(1) Includes a $47 million after-tax charge in connection with the termination of a long-term power purchase agreement and an $8 million after-tax charge related to the sale of our interest in a long-term power tolling contract. Also in 2005, we adopted a new accounting standard that resulted in the recognition of the cumulative effect of a change in accounting principle.

(2) Includes a $112 million after-tax charge related to our interest in a long-term power tolling contract that was divested in 2005 and a $43 million after-tax charge resulting from the termination of long-term power purchase agreements.

(3) Reflects the net impact of the discontinued operations of our indirect wholly-owned subsidiary, Virginia Power Energy Marketing, Inc., which was transferred to Dominion through a series of dividend distributions on December 31, 2005.

(4) The reapplication of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, to the Virginia jurisdiction of our generation operations resulted in a $158 million after-tax extraordinary charge. See Note 2 to our Consolidated Financial Statements.

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

MD&A discusses our results of operations and general financial condition. MD&A should be read in conjunction with Item 1. Business and our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

CONTENTS OF MD&A

Our MD&A consists of the following information:

- Forward-Looking Statements
- Accounting Matters
- Results of Operations
- Segment Results of Operations
- Liquidity and Capital Resources
- Future Issues and Other Matters

FORWARD-LOOKING STATEMENTS

This report contains statements concerning 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 such words as anticipate, estimate, forecast, expect, believe, should, could, plan, may, target or other similar words.

We make forward-looking statements with full knowledge that risks and uncertainties exist that may cause actual results to differ materially from predicted results. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Additionally, other factors may cause actual results to differ materially from those indicated in any forward-looking statement. These factors include but are not limited to:

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events, including hurricanes and severe storms, that can cause outages and property damage to our facilities;
- State and federal legislative and regulatory developments and changes to environmental and other laws and regulations, including those related to climate change, GHG emissions and other emissions to which we are subject;
- Cost of environmental compliance, including those costs related to climate change;
- Risks associated with the operation of nuclear facilities;
- Fluctuations in energy-related commodity prices and the effect these could have on our earnings, liquidity position and the underlying value of our assets;
- Capital market conditions, including the availability of credit and our ability to obtain financing on reasonable terms;
- Risks associated with our membership and participation in PJM related to obligations created by the default of other participants;
- Price risk due to securities held as investments in nuclear decommissioning trusts;
- Fluctuations in interest rates;
- Changes in federal and state tax laws and regulations;

Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;
Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
The risks of operating businesses in regulated industries that are subject to changing regulatory structures;
Changes to regulated electric rates collected by the Company, including the outcome of our 2009 base rate review, and the timing of such collection as it relates to fuel costs;
Timing and receipt of regulatory approvals necessary for planned construction or expansion projects;
The inability to complete planned construction or expansion projects within the terms and time frames initially anticipated;
Changes in rules for the RTO in which we participate, including changes in rate designs and capacity models;
Political and economic conditions, including the threat of domestic terrorism, inflation and deflation; and
Adverse outcomes in litigation matters.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors.

Our forward-looking statements are based on our beliefs and assumptions using information available at the time the statements are made. We caution the reader not to place undue reliance on our forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results.

We undertake no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

Accounting Matters

Critical Accounting Policies and Estimates

We have identified the following accounting policies, including certain inherent estimates, 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 our financial condition or results of operations under different conditions or using different assumptions. We have discussed the development, selection and disclosure of each of these policies with our Board of Directors which also serves as our Audit Committee.

Accounting For Derivative Contracts and Other Instruments at Fair Value

We use derivative contracts such as futures, swaps, forwards, options and FTRs to manage the commodity and financial markets risks of our business operations. Derivative contracts, with certain exceptions, are subject to fair value accounting, as prescribed by SFAS No. 157, *Fair Value Measurements* and are reported in our Consolidated Balance Sheets at fair value. Accounting requirements for derivatives and related hedging activities are complex and may be subject to further clarification by standard-setting bodies. The majority of investments held in nuclear decommissioning trust funds are also subject to fair value accounting. See Note 8 of our Consolidated Financial Statements for further information on our fair value measurements.

Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, we seek indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, or if we believe that observable pricing information is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases we must estimate prices based on available historical and near-term future price information and use of statistical methods, including regression analysis, that reflect our market assumptions.

For options and contracts with option-like characteristics where observable pricing information is not available from external sources, we generally use a modified Black-Scholes Model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. We use other option models under special circumstances, including a Spread Approximation Model, when contracts include different commodities or commodity locations and a Swing Option Model, when contracts allow either the buyer or seller the ability to exercise within a range of quantities. For contracts with unique characteristics, we may estimate fair value using a discounted cash flow approach deemed appropriate under the circumstances and applied consistently from period to period. For individual contracts, the use of different valuation models or assumptions could have a significant effect on the contract s estimated fair value.

In accordance with SFAS No. 157, we maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. We utilize the following fair value hierarchy as prescribed by SFAS No. 157, which categorizes the inputs used to measure fair value into three levels:

Level 1 Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as the majority of exchange-traded derivatives, exchange-listed equities and Treasury securities held in nuclear decommissioning trust funds.

Level 2 Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 primarily include non-exchange traded derivatives such as over-the-counter forwards and swaps, interest rate swaps, foreign currency forwards and options and municipal bonds and short-term debt securities held in nuclear decommissioning trust funds.

Level 3 Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 consist of long-dated commodity derivatives, FTRs and other modeled commodity derivatives.

Fair value measurements are categorized as Level 3 when a significant amount of price or other inputs that are considered to be unobservable are used in their valuations. Long-dated commodity derivatives are based on unobservable inputs due to

the length of time to settlement and absence of market activity and are therefore categorized as Level 3. FTRs are categorized as Level 3 fair value measurements because the only relevant pricing available comes from PJM auctions, which is accurate for day-one valuation, but generally is not considered to be representative of the ultimate settlement values. Other modeled commodity derivatives have unobservable inputs in their valuation, mostly due to non-transparent and illiquid markets.

As of December 31, 2008, our net balance of commodity derivatives categorized as Level 3 fair value measurements was a net liability of $69 million. A hypothetical 10% increase in commodity prices would decrease the net liability by $3 million, while a hypothetical 10% decrease in commodity prices would increase the net liability by $3 million.

SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of our own nonperformance risk on our liabilities. We apply credit adjustments to our derivative fair values in accordance with the guidance in SFAS No. 157. These credit adjustments are currently not material to our derivative fair values.

For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could require discontinuance of hedge accounting or could affect the timing of the reclassification of gains and/or losses on cash flow hedges from AOCI into earnings.

Accounting for Regulated Operations

The accounting for our regulated electric operations differs from the accounting for nonregulated operations in that we are required to reflect the effect of rate regulation in our Consolidated Financial Statements. For regulated businesses subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, we defer these costs as regulatory assets that otherwise would be expensed by nonregulated companies. Likewise, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the period authorized by the regulator.

As discussed further in Note 2 to our Consolidated Financial Statements, in April 2007, the Virginia General Assembly passed legislation that returns the Virginia jurisdiction of our utility generation operations to cost-of-service rate regulation. As a result, we reapplied the provisions of SFAS No. 71 to those operations on April 4, 2007, the date the legislation was enacted. The reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations resulted in a $259 million ($158 million after tax) extraordinary charge and the reclassification of $195

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Management s Discussion and Analysis of Financial Condition and Results of Operations, Continued

million ($119 million after tax) of unrealized gains from AOCI related to nuclear decommissioning trust funds. This established a $454 million long-term regulatory liability for amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our utility nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations*. In connection with the reapplication of SFAS No. 71, we prospectively changed certain of our accounting policies for the Virginia jurisdiction of our generation operations to those used by cost-of-service rate-regulated entities. Other than the extraordinary item previously discussed, the overall impact of these changes was not material to our results of operations or financial condition in 2007.

We evaluate whether or not recovery of our regulatory assets through future rates is probable and make various assumptions in our analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions or historical experience, as well as discussions with applicable regulatory authorities. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made. We currently believe the recovery of our regulatory assets is probable. See Notes 2 and 11 to our Consolidated Financial Statements.

Asset Retirement Obligations

We recognize liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These asset retirement obligations (AROs) are recognized at fair value as incurred, and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, we estimate the fair value of our AROs using present value techniques, in which we make various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. AROs currently reported in our Consolidated Balance Sheets were measured during a period of historically low interest rates. The impact on measurements of new AROs, or remeasurements of existing AROs, using different cost escalation rates in the future, may be significant. When we revise any assumptions used to calculate the fair value of existing AROs, we adjust the carrying amount of both the ARO liability and the related long-lived asset. We accrete the ARO liability to reflect the passage of time. In 2008, 2007 and 2006, we recognized $38 million, $38 million and $40 million, respectively, of accretion and expect to incur $40 million in 2009. Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations, we began recording accretion and depreciation associated with nuclear decommissioning AROs, formerly charged to expense, as an adjustment to the regulatory liability for nuclear decommissioning trust funds previously discussed, in order to match the recognition for rate-making purposes.

A significant portion of our AROs relates to the future decommissioning of our nuclear facilities. At December 31, 2008, nuclear decommissioning AROs, which are reported in the Generation segment, totaled $673 million, representing approximately 94% of our total AROs. Based on their significance, the following discussion of critical assumptions inherent in determin-

ing the fair value of AROs relates to those associated with our nuclear decommissioning obligations.

We utilize periodic site-specific base year cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our nuclear plants. We obtained updated cost studies for both of our nuclear plants in 2006 which reflected increases in base year costs. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results. In addition, our cost estimates include cost escalation rates that are applied to the base year costs. The selection of these cost escalation rates is dependent on subjective factors which we consider to be a critical assumption.

We determine cost escalation rates, which represent projected cost increases over time, due to both general inflation and increases in the cost of specific decommissioning activities, for each of our nuclear facilities. The use of alternative rates could have been material to the liabilities recognized. For example, had we increased the cost escalation rate by 0.5%, the amount recognized as of December 31, 2008, for our AROs related to nuclear decommissioning would have been $123 million higher.

Revenue Recognition Unbilled Revenue

We recognize and record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters which is performed on a systematic basis throughout the month. At the end of each month, the amounts of electric energy delivered to customers, but not yet billed, is estimated and recorded as unbilled revenue. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. Our customer receivables included $341 million and $270 million of accrued unbilled revenue at December 31, 2008 and 2007, respectively.

The calculation of unbilled revenues is complex and includes numerous estimates and assumptions including historical usage, applicable customer rates, weather factors and total daily electric generation supplied adjusted for line losses. Changes in generation patterns, customer usage patterns, meter accuracy and other factors, which are the basis for the estimates of unbilled revenues, could have a significant effect on the calculation and therefore on our results of operations and financial condition.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret the laws differently. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material.

Prior to 2007, we established liabilities for tax-related contingencies when we believed that it was probable that a liability had been incurred and the amount could be reasonably estimated in accordance with SFAS No. 5, *Accounting for Contingencies*, and subsequently reviewed them in light of changing facts and circumstances. However, as discussed in Note 3 to our Consolidated Financial Statements, effective January 1, 2007, we adopted FIN 48, *Accounting for Uncertainty in Income Taxes*.

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Taking into consideration the uncertainty and judgment involved in the determination and filing of income taxes, FIN 48 establishes standards for recognition and measurement, in financial statements, of positions taken, or expected to be taken, by an entity in its income tax returns. Positions taken by an entity in its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by tax authorities with full knowledge of all relevant information. If we take or expect to take a tax return position that is not recognized in the financial statements, we disclose such amount as an unrecognized tax benefit. At December 31, 2008, we had $180 million of unrecognized tax benefits. For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility.

Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. We evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized. At December 31, 2008, we had no valuation allowances on our deferred tax assets.

Other

Accounting Standards and Policies

During 2008, 2007 and 2006, we were required to adopt several new accounting standards, which are discussed in Note 3 to our Consolidated Financial Statements. See Note 4 to our Consolidated Financial Statements for a discussion of recently issued accounting standards that will be adopted in the future.

In the fourth quarter of 2008, we revised our derivative income statement classification policy, described in Note 2 to our Consolidated Financial Statements, to present income statement activity for all non-trading derivatives based on the nature of the underlying risk. This includes unrealized changes in the fair value of and settlements of financially-settled derivatives not held for trading purposes, as well as gains or losses attributable to ineffectiveness, changes in the time value of options, and discontinuances of hedging instruments, all of which were previously presented in other operations and maintenance expense on a net basis. Our prior year Consolidated Statements of Income have been recast to conform to the 2008 presentation; however, this had no impact on earnings.

Results of Operations

Presented below is a summary of our consolidated results:

Year Ended December 31, (millions)	**2008**	**$ Change**	2007	$ Change	2006
Net Income	**$ 864**	**$ 416**	$ 448	$ (30)	$ 478

Overview

2008 vs. 2007

Net income increased 93% to $864 million, primarily due to the reinstatement of annual fuel rate adjustments for the Virginia jurisdiction of our generation operations effective July 1, 2007, with deferred fuel accounting for over- or under-recoveries of fuel costs, and the absence of an extraordinary charge incurred in 2007 in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.

2007 vs. 2006

Net income decreased by 6% to $448 million. Unfavorable drivers include an extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations, an increase in outage costs primarily due to an increase in the number of scheduled outage days at certain of our electric generating facilities and a decrease in gains from sales of emissions allowances. Favorable drivers include an increase in regulated electric sales resulting from favorable weather, customer growth and other factors, and lower fuel expense due to the reinstatement of annual fuel rate adjustments for the Virginia jurisdiction of our generation operations.

Analysis of Consolidated Operations

Presented below are selected amounts related to our results of operations:

Year Ended December 31, (millions)	**2008**	**$ Change**	2007	$ Change	2006
Operating Revenue	**$ 6,934**	**$ 753**	$ 6,181	$ 578	$ 5,603
Operating Expenses					
Electric fuel and energy purchases	**2,683**	**322**	2,361	128	2,233
Purchased electric capacity	**410**	**(19)**	429	(24)	453
Other energy-related commodity purchases	**24**	**(3)**	27	(29)	56
Other operations and maintenance	**1,405**	**8**	1,397	218	1,179
Depreciation and amortization	**608**	**40**	568	32	536
Other taxes	**183**	**10**	173	10	163
Other income	**52**	**(3)**	55	(20)	75
Interest and related charges	**309**	**5**	304	8	296
Income tax expense	**500**	**129**	371	87	284
Extraordinary item, net of tax		**158**	(158)	(158)	

An analysis of our results of operations for 2008 compared to 2007 and 2007 compared to 2006 follows:

2008 vs. 2007

Operating Revenue increased 12% to $6.9 billion, primarily reflecting the combined effects of:

- A $722 million increase in fuel revenue primarily due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;
- An $84 million increase associated with sales to wholesale customers primarily due to higher prices ($46 million) and increased volumes ($38 million); and

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Management s Discussion and Analysis of Financial Condition and Results of Operations, Continued

- A $56 million increase in new retail customer connections primarily in our residential and commercial customer classes; partially offset by
- A $95 million decrease in sales to retail customers due to a 10% decrease in cooling degree days and a 2% decrease in heating degree days.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 14% to $2.7 billion, primarily reflecting a $434 million increase in fuel costs, largely as a result of higher commodity prices, including purchased power, partially offset by a $113 million decrease due to the deferral of fuel expenses that were in excess of the fuel rate recovery.

Other operations and maintenance expense increased 1% to $1.4 billion, primarily reflecting:

- A $69 million increase resulting from higher salaries, wages and other benefits expenses and other general and administrative costs; partially offset by
- A $58 million decrease in outage costs resulting from a reduction in scheduled outages at certain of our electric generating facilities.

Depreciation and amortization expense increased 7% to $608 million, primarily due to an increase in depreciation rates for our generation assets ($36 million), and property additions ($15 million), partially offset by an $11 million decrease in amortization expense primarily associated with lower consumption of emissions allowances.

Interest and related charges increased 2% to $309 million, primarily due to a $43 million impact from additional borrowings, partially offset by a $23 million benefit related to the redemption of our Callable and Puttable Enhanced Securities (CAPES) and lower interest rates on variable rate debt ($15 million). See Note 15 to our Consolidated Financial Statements for additional information on the CAPES.

Income tax expense increased 35% to $500 million, reflecting higher pre-tax income in 2008.

Extraordinary item reflects the absence of a $158 million after-tax charge in 2007 in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.

2007 vs. 2006

Operating Revenue increased 10% to $6.2 billion, reflecting the combined effects of:

- A $166 million increase due to the impact of a comparatively higher fuel rate implemented in July 2007, for certain customer jurisdictions;
- A $162 million increase in sales to retail customers attributable to variations in rates resulting from changes in sales mix and other factors ($95 million) and new customer connections ($67 million) primarily in our residential and commercial customer classes;
- A $131 million increase in sales to retail customers due to an increase in the number of heating and cooling degree days. As compared to the prior year, we experienced a 15% increase in cooling degree days and a 10% increase in heating degree days;
- An $80 million increase in sales to wholesale customers primarily due to increased volumes; and
- A $42 million increase resulting primarily from higher ancillary service revenue reflecting higher regulation and operating reserves revenue received from PJM.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 6% to $2.4 billion, primarily reflecting a $536 million increase in underlying fuel costs, including those subject to deferral accounting due to higher consumption of fossil fuel and purchased power resulting from an increase in the number of heating and cooling degree days, higher commodity costs and a change in generation mix. This increase was largely offset by a $408 million decrease primarily due to the deferral of fuel expenses that were in excess of current period fuel rate recovery.

Purchased electric capacity expense decreased 5% to $429 million, primarily due to scheduled capacity reductions for certain long-term power purchase contracts.

Other energy-related commodity purchases expense decreased 52% to $27 million, primarily reflecting a decrease in nonutility coal activities that have been substantially exited.

Other operations and maintenance expense increased 18% to $1.4 billion, primarily reflecting:

- A $74 million increase in outage costs related to scheduled outages at certain of our generating facilities;
- A $54 million decrease in gains from the sale of emissions allowances held for consumption;
- A $40 million increase due to higher salaries and wages ($42 million) and incentive-based compensation ($30 million), partially offset by a decrease in pension and other postretirement benefits expense ($32 million);
- A $34 million increase related to services provided by Dominion Resources Services, Inc. (DRS), an affiliate that provides accounting, legal, finance and certain administrative and technical services to us; and
- A $23 million increase related to outside services for tree trimming and brush removal and other expenses; partially offset by
- A $16 million decrease in expenses for major storms and service restoration associated with our distribution operations.

Depreciation and amortization expense increased 6% to $568 million, due to incremental expense resulting from property additions ($12 million), a change in depreciation rates for our generation assets to reflect the results of a new depreciation study ($10 million) and increased amortization expense associated with emissions allowances held for consumption ($10 million).

Other taxes increased 6% to $173 million, primarily due to the recognition of increased property taxes in 2007, reflecting changes in tax rates and assessed valuations.

Other income decreased 27% to $55 million, resulting primarily from the recognition of decommissioning trust earnings as a regulatory liability due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.

Extraordinary item reflects a $158 million after-tax charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.

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Outlook

We believe our operating businesses will provide stable growth in net income in 2009. Our expected results for 2009 include the following growth factors:

- An increase in earnings assuming an increase in base rates resulting from the 2009 base rate review, normal weather in our utility service territory, rate adjustments for certain generation and transmission expansion projects and continued growth in sales. Despite the recent economic downturn we expect continued growth in sales due to several factors including our limited exposure to industrial customers, an unemployment rate in Virginia that is below the national average, a growing number of energy-intensive computer data centers and significant government presence in our Northern Virginia service territory and U.S. military base closures and reassignments that have resulted in personnel being shifted to facilities in Virginia such as Fort Lee and Fort Belvoir.

The increase in 2009 is expected to be partially offset by:

- Higher interest expense reflecting difficult credit market conditions; and
- An increase in costs for Dominion-sponsored employee pension and other postretirement benefit plans, in which our employees participate, largely reflecting the impact of 2008 declines in the market values of investments held to fund these obligations.

Segment Results of Operations

Presented below is a summary of contributions by our operating segments to net income:

Year Ended December 31,	**2008**	**$ Change**	2007	$ Change	2006
(millions)					
DVP	**$ 307**	**$ (35)**	$ 342	$ 3	$ 339
Generation	**583**	**307**	276	125	151
Primary operating segments	**890**	**272**	618	128	490
Corporate and Other	**(26)**	**144**	(170)	(158)	(12)
Consolidated	**$ 864**	**$ 416**	$ 448	$ (30)	$ 478

DVP

Presented below are operating statistics related to our DVP operations:

Year Ended December 31,	**2008**	**% Change**	2007	% Change	2006
Electricity delivered (million mwhrs)(1)	**84.0**	**(1)%**	84.7	6%	79.8
Degree days (electric service area):					
Cooling(2)	**1,621**	**(10)**	1,794	15	1,557
Heating(3)	**3,426**	**(2)**	3,500	10	3,178
Average electric delivery customer accounts (thousands)(4)	**2,386**	**1**	2,361	1	2,327

(1) Includes electricity delivered through the retail choice program for our Virginia jurisdictional electric customers.

(2) Cooling degree days are units measuring the extent to which the average daily temperature is greater than 65 degrees, and are calculated as the difference between 65 degrees and the average temperature for that day.

(3) Heating degree days are units measuring the extent to which the average daily temperature is less than 65 degrees, and are calculated as the difference between 65 degrees and the average temperature for that day.
(4) Thirteen-month average.

Presented below, on an after-tax basis, are the key factors impacting DVP s net income contribution:

2008 vs. 2007

(millions)	Increase (Decrease)
Regulated electric sales:	
Weather	**$ (14)**
Customer growth	**9**
Other	**(9)**
Storm damage and service restoration distribution operations[1]	**(10)**
Interest expense	**(9)**
Other	**(2)**
Change in net income contribution	**$ (35)**

(1) Reflects an increase in storm damage and service restoration costs resulting from more severe weather during 2008.

2007 vs. 2006

(millions)	Increase (Decrease)
Regulated electric sales:	
Weather	$ 22
Customer growth	11
Storm damage and service restoration distribution operations[1]	9
Reliability and outside services expenses	(18)
Salaries, wages and benefits expense	(11)
Other	(10)
Change in net income contribution	$ 3

(1) Primarily resulting from the absence in 2007 of expenses associated with tropical storm Ernesto in September 2006.

Generation

Presented below are operating statistics related to our Generation operations:

Year Ended December 31,	**2008**	**% Change**	2007	% Change	2006
Electricity supplied (million mwhrs)	**84.0**	**(1)%**	84.7	6%	79.7
Degree days (electric service area):					
Cooling	**1,621**	**(10)**	1,794	15	1,557
Heating	**3,426**	**(2)**	3,500	10	3,178

Management s Discussion and Analysis of Financial Condition and Results of Operations, Continued

Presented below, on an after-tax basis, are the key factors impacting Generation s net income contribution:

2008 vs. 2007

(millions)		**Increase (Decrease)**
Virginia fuel expenses(1)	**$**	**243**
Outage costs		**38**
Regulated electric sales:		
Customer growth		**16**
Weather		**(27)**
Other(2)		**26**
Capacity expense(3)		**13**
Sale of emissions allowances		**7**
Depreciation expense		**(27)**
Other		**18**
Change in net income contribution	**$**	**307**

(1) Primarily reflects the reapplication of deferred fuel accounting effective July 1, 2007, for the Virginia jurisdiction of our generation operations.
(2) Primarily reflects higher margins associated with wholesale customers.
(3) Primarily reflects a reduction in scheduled capacity for certain long-term power purchase contracts.

2007 vs. 2006

(millions)		Increase (Decrease)
Virginia fuel expenses(1)	$	120
Regulated electric sales:		
Weather		37
Customer growth		20
Ancillary service revenue		27
Capacity expense		13
Outage costs(2)		(45)
Sale of emissions allowances		(34)
Depreciation expense		(18)
Salaries, wages and benefits expense		(17)
Other		22
Change in net income contribution	$	125

(1) Primarily reflects the reapplication of deferred fuel accounting effective July 1, 2007, partially offset by increased consumption of fossil fuel and higher purchased power costs during the first six months of 2007.
(2) Primarily reflects an increase in scheduled outage costs for certain nuclear and fossil units.

Corporate and Other

Presented below are the Corporate and Other segment s after-tax results.

Year Ended December 31, (millions)	**2008**	2007	2006
Specific items attributable to operating segments	**$ (23)**	$ (166)	$ (12)
Other corporate operations	**(3)**	(4)	
Total net expense	**$ (26)**	$ (170)	$ (12)

Specific Items Attributable To Operating Segments

Corporate and Other primarily includes specific items attributable to our primary operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments. See Note 23 to our Consolidated Financial Statements for a discussion of these items.

Liquidity and Capital Resources

We depend 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 provided by operations are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through issuances of debt and/or equity securities.

Impact of Recent Credit Market Events

Despite recent disruptions in the credit markets, we have sufficient access to liquidity for our daily operations through our credit facilities discussed in *Financing Cash Flows and Liquidity*. We expect our operations to provide sufficient cash flow to fund maintenance capital expenditures and maintain or grow our dividend to Dominion; however, we expect to access the capital markets to fund growth capital expenditures. If necessary, we have the flexibility to mitigate the need for future debt financings and equity issuances, by postponing or cancelling certain planned capital expenditures.

At December 31, 2008, we had $2.4 billion of unused capacity under our joint credit facility. See discussion under *Joint Credit Facilities and Short-Term Debt*.

A summary of our cash flows is presented below:

Year Ended December 31, (millions)	**2008**	2007	2006
Cash and cash equivalents at beginning of year	**$ 49**	$ 18	$ 54
Cash flows provided by (used in):			
Operating activities	**1,235**	1,216	1,080
Investing activities	**(2,003)**	(1,306)	(960)
Financing activities	**746**	121	(156)
Net increase (decrease) in cash and cash equivalents	**(22)**	31	(36)
Cash and cash equivalents at end of year	**$ 27**	$ 49	$ 18

Operating Cash Flows

In 2008, net cash provided by operating activities increased by $19 million as compared to 2007. The increase is primarily due to lower income tax payments and a benefit from the reinstatement of annual fuel rate adjustments for the Virginia jurisdiction effective July 1, 2007, partially offset by the negative impact of milder weather on retail sales and unfavorable changes in working capital. We believe that our operations provide a stable source of cash flow to contribute to planned levels of capital expenditures and provide dividends to Dominion. However, our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows, which are discussed in Item 1A. Risk Factors.

Credit Risk

Our exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Presented below is a summary of our gross credit exposure as of December 31, 2008, for these activities. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights.

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(millions)	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
Investment grade[1]	**$ 46**	**$ 16**	**$ 30**
Non-investment grade[2]	**12**		**12**
No external ratings:			
Internally rated investment grade[3]	**16**		**16**
Internally rated non-investment grade			
Total	**$ 74**	**$ 16**	**$ 58**

(1) Designations as investment grade are based on minimum credit ratings assigned by Moody s and Standard & Poor s. The five largest counterparty exposures, combined, for this category represented approximately 43% of the total net credit exposure.
(2) The only counterparty exposure for this category represented 21% of the total net credit exposure.
(3) The only two counterparty exposures, combined, for this category represented 27% of the total net credit exposure.

Investing Cash Flows

In 2008, net cash used in investing activities increased by $697 million as compared to 2007, primarily reflecting an increase in capital expenditures for generation and transmission construction projects, including our Virginia City Hybrid Energy Center.

Financing Cash Flows and Liquidity

We rely on banks and capital markets as significant sources of funding for capital requirements not satisfied by the cash provided by our operations. As discussed in *Credit Ratings*, our ability to borrow funds or issue securities and the return demanded by investors are affected by our credit ratings. In addition, the raising of external capital is subject to meeting certain regulatory requirements, including registration with the SEC and approval from the Virginia Commission.

In 2008, net cash provided by financing activities increased by $625 million as compared to 2007. This change is due to higher net issuances of short-term debt and affiliated current borrowings in 2008 versus net repayments in 2007, partially offset by the 2008 repayment of affiliated notes payable.

Joint Credit Facilities And Short-Term Debt

We use short-term debt, primarily commercial paper, to fund working capital requirements and as a bridge to long-term debt financing. The level of our borrowings may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations.

Our credit facility commitments are with a large consortium of banks, including Lehman Brothers Holdings, Inc. (Lehman). In September 2008, Lehman filed for protection under Chapter 11 of the federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York. At December 31, 2008, Lehman s total commitment to our credit facilities was less than six percent of the aggregate commitment from the consortium of banks. We do not believe that the potential reduction in available capacity under these credit facilities that could result from Lehman s bankruptcy will have a significant impact on our liquidity.

Excluding commitments provided by Lehman, our short-term financing is supported by a $2.8 billion five-year joint revolving

credit facility with Dominion dated February 2006, which is scheduled to terminate in February 2011. This credit facility is being used for working capital, as support for the combined commercial paper programs of Dominion and us and for other general corporate purposes. This credit facility can also be used to support up to $1.5 billion of letters of credit.

In addition to the credit facility commitments of $2.8 billion disclosed above, we also have a $182 million five-year credit facility, excluding commitments provided by Lehman, that supports certain of our tax-exempt financings.

At December 31, 2008, total outstanding commercial paper supported by the joint credit facility was $297 million, all of which were our borrowings, and the total amount of letter of credit issuances was $187 million, of which less than $86 million were issued on our behalf.

At December 31, 2008, capacity available under the joint credit facility was approximately $2.4 billion.

Long-Term Debt

During 2008, we issued the following long-term debt:

Type (millions)	Principal	Rate	Maturity
Senior notes	**$ 600**	**5.40%**	**2018**
Senior notes	**700**	**8.875%**	**2038**
Total senior notes issued	**$ 1,300**		

In January 2008, we borrowed $30 million in connection with the Economic Development Authority of the City of Chesapeake Pollution Control Refunding Revenue Bonds, Series 2008 A, which mature in 2032 and bear interest at an initial coupon rate of 3.6% for the first five years and at a market rate to be determined thereafter. The proceeds were used to refund the principal amount of the Industrial Development Authority of the City of Chesapeake Money Market Municipals Pollution Control Revenue Bonds, Series 1985 that would otherwise have matured in February 2008.

In November 2008, we borrowed $122 million in connection with the Industrial Development Authority of the Town of Louisa Pollution Control Refunding Revenue Bonds, Series 2008 A and B, which mature in 2035 and bear interest at an initial coupon rate of 5.375% for the first five years and at a market rate to be determined thereafter. The proceeds were used to refund the principal amount of the Industrial Development Authority of the Town of Louisa Money Market Municipals Pollution Control Revenue Bonds, Series 1984 and 1985 that would have otherwise matured in December 2008.

In November 2008, we borrowed approximately $38 million in connection with the Industrial Development Authority of the Town of Louisa Pollution Control Refunding Revenue Bonds, Series 2008 C, which mature in 2035 and bear interest at an initial coupon rate of 5.0% for the first three years and at a market rate to be determined thereafter. The proceeds were used to refund the principal amount of the Industrial Development Authority of the Town of Louisa Money Market Municipals Pollution Control Revenue Bonds, Series 1987 and the Industrial Development Authority of the Town of Louisa Pollution Control Revenue Bonds, Series 1994 that would have otherwise matured in December 2015 and January 2024, respectively.

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Management s Discussion and Analysis of Financial Condition and Results of Operations, Continued

Including the amounts discussed above, during 2008, we repaid $965 million of long-term debt and notes payable, which also includes the repayment of $412 million 7.375% unsecured Junior Subordinated Notes and the related redemption of all 16 million units of the $400 million 7.375% Virginia Power Capital Trust II preferred securities due July 30, 2042. These securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions.

Common Shareholder s Equity

In December 2008, as approved by the Virginia Commission, we issued 11,786 shares of our common stock to Dominion reflecting the conversion of $350 million of short-term demand note borrowings from Dominion to equity.

Borrowings from Parent

We have the ability to borrow funds from Dominion under both short-term and long-term borrowing arrangements. At December 31, 2008, our nonregulated subsidiaries had outstanding borrowings, net of repayments, under the Dominion money pool of $198 million. Our short-term demand note borrowings from Dominion were $219 million at December 31, 2008. There were no long-term borrowings from Dominion at December 31, 2008.

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. We believe that our current credit ratings provide sufficient access to the capital markets. However, disruptions in the banking and capital markets not specifically related to us may affect our 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 our credit ratings. Credit ratings should be evaluated independently and are subject to revision or withdrawal at any time by the assigning rating organization. Our credit ratings are most affected by our financial profile, mix of regulated and nonregulated businesses and respective cash flows, changes in methodologies used by the rating agencies, event risk, if applicable, and the credit ratings of our parent company, Dominion.

In April 2008, Fitch upgraded its credit ratings for our preferred stock and senior unsecured and junior subordinated debt securities, and affirmed its F2 commercial paper rating.

Our credit ratings as of February 1, 2009 follow:

	Fitch	Moody s	Standard & Poor s
Mortgage bonds	**A**	**A3**	**A**
Senior unsecured (including tax-exempt) debt securities	**A-**	**Baa1**	**A-**
Junior subordinated debt securities	**BBB+**	**Baa2**	**BBB**
Preferred stock	**BBB+**	**Baa3**	**BBB**
Commercial paper	**F2**	**P-2**	**A-2**

As of February 1, 2009, Fitch, Moody s and Standard & Poor s maintain a stable outlook for their respective ratings of our company.

Generally, a downgrade in our credit rating would not restrict our ability to raise short-term or long-term financing as long as our credit rating remains investment grade , but it would increase the cost of borrowing. We work closely with Fitch, Moody s and Standard & Poor s, with the objective of maintaining our current credit ratings. In order to maintain our current ratings, we may find it necessary to modify our business plans and such changes may adversely affect our growth.

Debt Covenants

As part of borrowing funds and issuing debt (both short-term and long-term) or preferred securities, we must enter into 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 our 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 us. Some of the typical covenants include:

- The timely payment of principal and interest;
- Information requirements, including submitting financial reports filed with the SEC to lenders;
- Performance obligations, audits/inspections, continuation of the basic nature of business, restrictions on certain matters related to merger or consolidation, restrictions on disposition of all or substantially all of our assets;
- Compliance with collateral minimums or requirements related to mortgage bonds; and
- Limitations on liens.

We are required to pay minimal annual commitment fees to maintain the joint credit facility. In addition, the joint credit agreement contains various terms and conditions that could affect our ability to borrow funds under this facility. They include a maximum debt to total capital ratio and cross-default provisions.

The ratio of our debt to total capital, as defined by the agreement, should not exceed 65% at the end of any fiscal quarter. As of December 31, 2008, our debt to total capital ratio calculated pursuant to the terms of the agreement was 51%. Under the agreement s cross-default provisions, if we or any of our material subsidiaries fail to make payment on various debt obligations in excess of $35 million, we may be required by the lenders to accelerate our repayment of any outstanding borrowings under the credit facility and the lenders could terminate their commitment to lend funds to us. However, any defaults on indebtedness by Dominion or any material subsidiaries of Dominion would not affect the lenders commitment to us under the joint credit agreement.

We monitor the covenants on a regular basis in order to ensure that events of default will not occur. As of December 31, 2008, there were no events of default under our covenants.

Dividend Restrictions

The Virginia Commission may prohibit any public service company from declaring or paying a dividend to an affiliate, if found to be detrimental to the public interest. At December 31, 2008, the Virginia Commission had not restricted our payment of dividends.

Certain agreements associated with our joint credit facility with Dominion contain restrictions on the ratio of our debt to total capitalization. These limitations did not restrict our ability to pay dividends to Dominion as of December 31, 2008.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

Contractual Obligations

We are party to numerous contracts and arrangements obligating us to make cash payments in future years. These contracts include financing arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. Presented below is a table summarizing cash payments that may result from contracts to which we are a party as of December 31, 2008. For purchase obligations and other liabilities, amounts are based upon contract terms, including fixed and minimum quantities to be purchased at fixed or market-based prices. Actual cash payments will be based upon actual quantities purchased and prices paid and will likely differ from amounts presented below. The table excludes all amounts classified as current liabilities in our Consolidated Balance Sheets, other than current maturities of long-term debt, interest payable and interest rate swaps. The majority of our current liabilities will be paid in cash in 2009.

(millions)	2009	2010-2011	2012-2013	2014 and thereafter	Total
Long-term debt[1]	**$ 124**	**$ 261**	**$ 1,034**	**$ 4,707**	**$ 6,126**
Interest payments	**362**	**694**	**640**	**4,566**	**6,262**
Leases	**27**	**44**	**22**	**22**	**115**
Purchase obligations[2]:					
Purchased electric capacity for utility operations	**361**	**699**	**710**	**1,499**	**3,269**
Fuel commitments for utility operations	**882**	**1,056**	**471**	**536**	**2,945**
Transportation and storage	**19**	**32**	**19**	**32**	**102**
Other	**137**	**89**	**2**		**228**
Total cash payments[3]	**$ 1,912**	**$ 2,875**	**$ 2,898**	**$ 11,362**	**$ 19,047**

(1) Based on stated maturity dates rather than the earlier redemption dates that could be elected by instrument holders.

(2) Amounts exclude open purchase orders for services that are provided on demand, the timing of which cannot be determined.

(3) Excludes regulatory liabilities, AROs and employee benefit plan contributions that are not contractually fixed as to timing and amount. See Notes 11, 12 and 19 to our Consolidated Financial Statements. Due to uncertainty about the timing and amounts that will ultimately be paid, $140 million of income taxes payable associated with unrecognized tax benefits are excluded. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete fiscal year. See Note 5 to our Consolidated Financial Statements.

Planned Capital Expenditures

Our planned capital expenditures are expected to total approximately $2.6 billion, $2.3 billion and $2.5 billion in 2009, 2010 and 2011, respectively. We expect to fund our capital expenditures with cash from operations and a combination of securities issuances and capital contributions from Dominion. Our planned capital expenditures include capital projects that are subject to approval by regulators and our Board of Directors. Our annual capital expenditures for plant and equipment for 2009,

including environmental upgrades and construction improvements, are expected to total approximately:

- Generation segment: $1.8 billion for our generation operations, including nuclear fuel; and
- DVP segment: $417 million for transmission operations and $447 million for distribution operations.

Based on available generation capacity and current estimates of growth in customer demand, we will need additional generation capacity in the future. See *Generation-Properties* in Item 1. Business for a discussion of our expansion plans.

We may choose to postpone or cancel certain planned capital expenditures in order to mitigate the need for future debt financings and equity issuances.

Future Issues and Other Matters

See Item 1. Business, Item 3. Legal Proceedings and Note 20 to our Consolidated Financial Statements for additional information on various environmental, regulatory, legal and other matters that may impact our future results of operations and/or financial condition.

Environmental Matters

We are 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.

Environmental Protection and Monitoring Expenditures

We incurred approximately $125 million, $121 million and $102 million of expenses (including depreciation) during 2008, 2007 and 2006, respectively, in connection with environmental protection and monitoring activities and expect these expenses to be approximately $149 million and $142 million in 2009 and 2010, respectively. In addition, capital expenditures related to environmental controls were $116 million, $189 million and $170 million for 2008, 2007 and 2006, respectively. These expenditures are expected to be approximately $113 million and $104 million for 2009 and 2010, respectively.

Future Environmental Regulations

We expect that there may be federal legislative or regulatory action regarding the regulation of GHG emissions, regarding compliance with more stringent air emission standards, and regarding regulation of cooling water intake structures and discharges in the future. With respect to GHG emissions, the outcome in terms of specific requirements and timing is uncertain but may include a GHG emissions cap-and-trade program or a carbon tax for electric generators and natural gas businesses. With respect to emission reductions, specific requirements will depend on how the EPA and/or states replace CAMR and the outcome of the EPA s response to the CAIR remand. With respect to cooling water intakes and discharges, we expect future federal regulation on cooling water intake structures and more focus by EPA and state regulatory authorities on thermal discharge issues. If any of these new proposals are adopted, additional significant expenditures may be required.

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Management s Discussion and Analysis of Financial Condition and Results of Operations, Continued

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The matters discussed in this Item may contain forward-looking statements as described in the introductory paragraphs under Part II, Item 7. MD&A of this Form 10-K. The reader s attention is directed to those paragraphs and Item 1A. Risk Factors for discussion of various risks and uncertainties that may impact the Company.

Market Risk Sensitive Instruments and Risk Management

Our financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates and equity security prices as described below. Commodity price risk is due to our exposure to market shifts for prices paid for commodities. Interest rate risk is generally related to our outstanding debt. In addition, we are exposed to investment price risk through various portfolios of debt and equity securities.

The following 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% unfavorable change in commodity prices and interest rates.

Commodity Price Risk

To manage price risk, we hold commodity-based financial derivative instruments for non-trading purposes associated with purchases of electricity, natural gas and other energy-related products. The derivatives used to manage our commodity price risk are executed within established policies and procedures and may include instruments such as futures, forwards, swaps, options and FTRs that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the hypothetical change in market prices of commodity-based financial derivative instruments is determined based on models that consider the market prices of commodities in future periods, the volatility of the market prices in each period, as well as the time value factors of the derivative instruments. Prices and volatility are principally determined based on observable market prices.

A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $23 million and $27 million in the fair value of our non-trading commodity-based financial derivatives as of December 31, 2008 and 2007, respectively.

The impact of a change in energy commodity prices on our non-trading commodity-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when such contracts are ultimately settled. For example, our expenses for power purchases, when combined with the settlement of commodity derivative instruments used for hedging purposes, will generally result in a range of prices for those purchases contemplated by the risk management strategy.

Interest Rate Risk

We manage our interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. We also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For financial instruments outstanding at December 31, 2008 and 2007, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $2 million.

Investment Price Risk

We are subject to investment price risk due to securities held as investments in decommissioning trust funds that are managed by third-party investment managers. These trust funds primarily hold marketable securities that are reported in our Consolidated Balance Sheets at fair value.

Following the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations, gains or losses on those decommissioning trust investments are deferred as regulatory liabilities.

We recognized net realized losses (net of investment income) on nuclear decommissioning trust investments of $57 million for 2008 and net realized gains (including investment income) of $28 million for 2007. Net realized gains and losses include gains and losses from the sale of investments as well as any other-than-temporary declines in fair value. In 2008, we recorded, in AOCI and regulatory liabilities, a reduction in unrealized gains on these investments of $233 million. In 2007, we recorded, in AOCI and regulatory liabilities, an increase in unrealized gains on these investments of $13 million.

Dominion sponsors employee pension and other postretirement benefit plans, in which our employees participate, that hold investments in trusts to fund benefit payments. Investment-related declines in these trusts, such as those experienced during 2008, will result in future increases in the periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash that we will provide to Dominion for our share of employee benefit plan contributions.

Risk Management Policies

We have established operating procedures with corporate management to 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, including the Company. 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. Based on Dominion s credit policies and our December 31, 2008 provision for credit losses, management believes that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

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Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder 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) and subsidiaries (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of income, common shareholder s equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to our consolidated financial statements, the Company changed its methods of accounting to adopt new accounting standards for fair value measurements in 2008 and uncertain tax positions in 2007.

/s/ Deloitte & Touche LLP

Richmond, Virginia

February 24, 2009

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Consolidated Statements of Income

Year Ended December 31, (millions)	**2008**	2007(1)	2006(1)
Operating Revenue	**$ 6,934**	$ 6,181	$ 5,603
Operating Expenses			
Electric fuel and energy purchases	**2,683**	2,361	2,233
Purchased electric capacity	**410**	429	453
Other energy-related commodity purchases	**24**	27	56
Other operations and maintenance:			
Affiliated suppliers	**399**	345	311
Other	**1,006**	1,052	868
Depreciation and amortization	**608**	568	536
Other taxes	**183**	173	163
Total operating expenses	**5,313**	4,955	4,620
Income from operations	**1,621**	1,226	983
Other income	**52**	55	75
Interest and related charges:			
Interest expense	**297**	274	266
Interest expense junior subordinated notes payable to affiliated trust	**12**	30	30
Total interest and related charges	**309**	304	296
Income from operations before income tax expense and extraordinary item	**1,364**	977	762
Income tax expense	**500**	371	284
Income from operations before extraordinary item	**864**	606	478
Extraordinary item(2)		(158)	
Net Income	**864**	448	478
Preferred dividends	**17**	16	16
Balance available for common stock	**$ 847**	$ 432	$ 462

(1) Our 2007 and 2006 Consolidated Statements of Income have been recast to reflect our revised derivative income statement classification policy described in Note 2 of our Consolidated Financial Statements.

(2) Reflects a $259 million ($158 million after-tax) extraordinary charge in connection with the reapplication of SFAS No. 71, Accounting for Certain Types of Regulation, to the Virginia jurisdiction of our generation operations.

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

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Consolidated Balance Sheets

At December 31, (millions)	2008	2007
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 27**	$ 49
Customer receivables (less allowance for doubtful accounts of $8 at both dates)	**940**	763
Affiliated receivables	**8**	53
Other receivables (less allowance for doubtful accounts of $7 and $9)	**74**	58
Inventories (average cost method):		
Materials and supplies	**275**	248
Fossil fuel	**272**	272
Prepayments	**28**	165
Regulatory assets	**212**	
Other	**75**	92
Total current assets	**1,911**	1,700
Investments		
Nuclear decommissioning trust funds	**1,053**	1,339
Other	**3**	16
Total investments	**1,056**	1,355
Property, Plant and Equipment		
Property, plant and equipment	**23,476**	21,838
Accumulated depreciation and amortization	**(8,915)**	(8,702)
Total property, plant and equipment, net	**14,561**	13,136
Deferred Charges and Other Assets		
Intangible assets	**210**	176
Regulatory assets	**921**	564
Other	**143**	132
Total deferred charges and other assets	**1,274**	872
Total assets	**$ 18,802**	$ 17,063

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At December 31, (millions)	2008	2007
LIABILITIES AND SHAREHOLDER S EQUITY		
Current Liabilities		
Securities due within one year	**$ 125**	$ 286
Short-term debt	**297**	257
Accounts payable	**436**	573
Payables to affiliates	**132**	80
Affiliated current borrowings	**417**	114
Accrued interest, payroll and taxes	**236**	234
Customer deposits	**116**	116
Other	**270**	123
Total current liabilities	**2,029**	1,783
Long-Term Debt		
Long-term debt	**6,000**	4,904
Junior subordinated notes payable to affiliated trust		412
Total long-term debt	**6,000**	5,316
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**2,485**	2,237
Asset retirement obligations	**715**	678
Regulatory liabilities	**760**	1,009
Other	**282**	242
Total deferred credits and other liabilities	**4,242**	4,166
Total liabilities	**12,271**	11,265
Commitments and Contingencies (see Note 20)		
Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholder s Equity		
Common stock no par(1)	**3,738**	3,388
Other paid-in capital	**1,110**	1,109
Retained earnings	**1,421**	1,015
Accumulated other comprehensive income	**5**	29
Total common shareholder s equity	**6,274**	5,541
Total liabilities and shareholder s equity	**$ 18,802**	$ 17,063

(1) 300,000 shares authorized, 209,833 shares and 198,047 shares outstanding at December 31, 2008 and 2007, respectively.
The accompanying notes are an integral part of our Consolidated Financial Statements.

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Consolidated Statements of Common Shareholder s Equity

(millions, except for shares)	Common Stock Shares (thousands)	Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2005	198	$ 3,388	$ 886	$ 842	$ 117	$ 5,233
Net income				478		478
Tax benefit from stock awards and stock options exercised			1			1
Dividends				(365)		(365)
Other comprehensive income, net of tax					45	45
Balance at December 31, 2006	198	3,388	887	955	162	5,392
Net income				448		448
Equity contribution by parent			220			220
Tax benefit from stock awards and stock options exercised			2			2
Dividends				(393)		(393)
Adoption of FIN 48				5		5
Other comprehensive loss, net of tax					(133)	(133)
Balance at December 31, 2007	198	3,388	1,109	1,015	29	5,541
Net income				**864**		**864**
Issuance of stock to parent	**12**	**350**				**350**
Tax benefit from stock awards and stock options exercised			**1**			**1**
Dividends				**(458)**		**(458)**
Other comprehensive loss, net of tax					**(24)**	**(24)**
Balance at December 31, 2008	**210**	**$ 3,738**	**$ 1,110**	**$ 1,421**	**$ 5**	**$ 6,274**

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

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Consolidated Statements of Comprehensive Income

Year Ended December 31, (millions)	**2008**	2007	2006
Net income	**$ 864**	$ 448	$ 478
Other comprehensive income (loss), net of taxes:			
Net deferred losses on derivatives hedging activities, net of $1, $1 and $6 tax	**(2)**	(1)	(10)
Changes in unrealized gains on nuclear decommissioning trust funds, net of $17, $80 and $(40) tax	**(29)**	(125)	62
Amounts reclassified to net income:			
Net realized (gains) losses on nuclear decommissioning trust funds, net of $(5), $2 and $7 tax	**8**	(3)	(9)
Net derivative (gains) losses-hedging activities, net of $1, $2 and $(2) tax	**(1)**	(4)	2
Other comprehensive income (loss)	**(24)**	(133)	45
Comprehensive income	**$ 840**	$ 315	$ 523

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

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Consolidated Statements of Cash Flows

Year Ended December 31, (millions)	2008	2007	2006
Operating Activities			
Net income	$ 864	$ 448	$ 478
Adjustments to reconcile net income to net cash from operating activities:			
Net change in realized and unrealized derivative (gains) losses	10	(67)	(2)
Depreciation and amortization	702	654	619
Deferred income taxes and investment tax credits, net	304	256	24
Extraordinary item, net of income taxes		158	
Gain on sale of emissions allowances held for consumption	(31)	(19)	(74)
Other adjustments	(15)	(39)	(27)
Changes in:			
Accounts receivable	(205)	(77)	30
Affiliated accounts receivable and payable	51	(17)	6
Deferred fuel expenses, net	(423)	(315)	99
Inventories	(27)	(15)	(62)
Prepayments	137	(35)	(42)
Accounts payable	(131)	165	1
Accrued interest, payroll and taxes	2	7	(61)
Other operating assets and liabilities	(3)	112	91
Net cash provided by operating activities	1,235	1,216	1,080
Investing Activities			
Plant construction and other property additions	(1,902)	(1,184)	(925)
Purchases of nuclear fuel	(135)	(111)	(122)
Purchases of securities	(455)	(551)	(550)
Proceeds from sales of securities	410	520	533
Proceeds from sales of emissions allowances held for consumption	45	9	75
Other	34	11	29
Net cash used in investing activities	(2,003)	(1,306)	(960)
Financing Activities			
Issuance (repayment) of short-term debt, net	40	(361)	(287)
Issuance (repayment) of affiliated current borrowings, net	653	(26)	129
Issuance of long-term debt	1,490	2,250	1,000
Repayment of long-term debt	(553)	(1,335)	(624)
Repayment of affiliated notes payable	(412)		
Common dividend payments	(441)	(377)	(349)
Preferred dividend payments	(17)	(16)	(16)
Other	(14)	(14)	(9)
Net cash provided by (used in) financing activities	746	121	(156)
Increase (decrease) in cash and cash equivalents	(22)	31	(36)
Cash and cash equivalents at beginning of year	49	18	54
Cash and cash equivalents at end of year	$ 27	$ 49	$ 18
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	$ 320	$ 305	$ 254
Income taxes	48	211	419
Significant noncash investing and financing activities[1]:			
Accrued capital expenditures	114		
Conversion of short-term and long-term borrowings payable to parent to equity	350	220	

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

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Notes to Consolidated Financial Statements

NOTE 1. NATURE OF OPERATIONS

Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. As of December 31, 2008, we served approximately 2.4 million retail customer accounts, including governmental agencies, as well as wholesale customers such as rural electric cooperatives and municipalities. We are a member of PJM, an RTO, and our electric transmission facilities are integrated into the PJM wholesale electricity markets. All of our common stock is owned by our parent company, Dominion.

We manage our daily operations through two primary operating segments: DVP and Generation. In addition, we also report a Corporate and Other segment that primarily includes specific items attributable to our operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments. Our assets remain wholly owned by us and our legal subsidiaries.

The terms Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Virginia Power, one or more of its consolidated subsidiaries or operating segments or the entirety of Virginia Power, including our Virginia and North Carolina operations and our consolidated subsidiaries.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

General

We make certain estimates and assumptions in preparing our Consolidated Financial Statements in accordance with GAAP. 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 revenue and expenses for the periods presented. Actual results may differ from those estimates.

Our Consolidated Financial Statements include, after eliminating intercompany transactions and balances, our accounts and those of our majority-owned subsidiaries.

In accordance with GAAP, we report certain contracts and instruments at fair value. See Note 6 for further information on fair value measurements in accordance with SFAS No. 157.

Certain amounts in our 2007 and 2006 Consolidated Financial Statements and footnotes have been recast to conform to the 2008 presentation. See Note 3 for discussion of the recast of our 2007 Consolidated Balance Sheet due to the adoption of FSP FIN 39-1, *Amendment of FIN* 39*, Offsetting of Amounts Related to Certain Contracts*. Additionally, in the fourth quarter of 2008, we revised our derivative income statement classification policy, described in *Derivative Instruments*, to present income statement activity for all non-trading derivatives based on the nature of the underlying risk. This includes unrealized changes in the fair value of and settlements of financially-settled derivatives not held for trading purposes, as well as gains or losses attributable to ineffectiveness, changes in the time value of options, and discontinuances of hedging instruments, which were previously presented in other operations and maintenance expense on a net basis. Our prior year Consolidated Statements of Income have

been recast to conform to the 2008 presentation; however, this had no impact on earnings.

Reapplication of SFAS No. 71

In March 1999, we discontinued the application of SFAS No. 71 to the majority of our generation operations upon the enactment of deregulation legislation in Virginia. Our transmission and distribution operations continued to apply the provisions of SFAS No. 71 since they remained subject to cost-of-service rate regulation.

In April 2007, the Virginia General Assembly passed legislation that returned the Virginia jurisdiction of our generation operations to cost-of-service rate regulation. As a result, we reapplied the provisions of SFAS No. 71 to those operations on April 4, 2007, the date the legislation was enacted. In connection with the reapplication of SFAS No. 71 to those operations, we prospectively changed certain of our accounting policies to those used by cost-of-service rate-regulated entities. Other than the extraordinary item discussed here, the overall impact of these changes was not material to our results of operations or financial condition in 2007. These policy changes are discussed further in *Derivative Instruments, Investments, Property, Plant and Equipment* and *Asset Retirement Obligations.*

The reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations resulted in a $259 million ($158 million after tax) extraordinary charge and the reclassification of $195 million ($119 million after tax) of unrealized gains from AOCI, related to nuclear decommissioning trust funds. This established a $454 million long-term regulatory liability for amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143.

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. Our customer receivables at December 31, 2008 and 2007 included $341 million and $270 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity delivered but not yet billed to our customers. We estimate unbilled revenue based on historical usage, applicable customer rates, weather factors and total daily electric generation supplied after adjusting for estimated losses of energy during transmission.

The primary types of sales and service activities reported as operating revenue are as follows:

- **Regulated electric sales** consist primarily of state-regulated retail electric sales and federally-regulated wholesale electric sales and electric transmission services; and
- **Other revenue** consists primarily of excess generation sold at market-based rates, miscellaneous service revenue from electric distribution operations and other miscellaneous revenue. Other revenue accounted for less than ten percent of operating revenue in 2008, 2007 and 2006.

Electric Fuel and Purchased Energy Deferred Costs

Where permitted by regulatory authorities, the differences between actual electric fuel and purchased energy expenses and the related levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. The deferral of costs in excess of current period fuel rate recovery is recognized as a regulatory asset, while rate recovery in excess of current period fuel expenses is recognized as a regulatory liability.

For electric fuel and purchased energy expenses, effective January 1, 2004, the fuel factor provisions for our Virginia retail customers were fixed until July 1, 2007. Effective July 1, 2007 and 2008, the fuel factor was adjusted as discussed under *Virginia Fuel Expenses* in Note 20. Of the cost of fuel used in electric generation and energy purchases to serve utility customers approximately 82% is currently subject to deferred fuel accounting, while substantially all of the remaining amount is subject to recovery through similar mechanisms.

Income Taxes

We file a consolidated federal income tax return and participate in an intercompany tax sharing agreement with Dominion and its subsidiaries. In addition, where applicable, we file combined income tax returns with Dominion and its subsidiaries in various states; otherwise, we file separate state income tax returns. Our current income taxes are based on our taxable income or loss, determined on a separate company basis.

SFAS No. 109, *Accounting for Income Taxes*, requires an asset and liability approach to accounting for income taxes. Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. We establish a valuation allowance when it is more likely than not that all, or a portion, of a deferred tax asset will not be realized. Where permitted by regulatory authorities, the treatment of temporary differences may differ from the requirements of SFAS No. 109. Accordingly, a regulatory asset is recognized if it is probable that future revenues will be provided for the payment of deferred tax liabilities.

Effective January 1, 2007, we adopted FIN 48. In our financial statements, we recognize positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information.

If we conclude that it is more-likely-than-not that a tax position, or some portion thereof, will not be sustained, the related tax benefits are not recognized in the financial statements. For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of income tax refunds receivable or changes in deferred taxes. Also, when uncertainty about the deductibility of an amount is limited to the timing of such deductibility, the increase in taxes payable (or reduction in tax refunds receivable) is accompanied by a decrease in deferred tax liabilities. Noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities; current payables are included in accrued interest, payroll and taxes, except when such amounts are presented net with amounts receivable from or amounts prepaid to tax authorities in prepayments.

Prior to the adoption of FIN 48, we established liabilities for tax-related contingencies when the incurrence of the liability was

determined to be probable and the amount could be reasonably estimated in accordance with SFAS No. 5*,* and reviewed them in light of changing facts and circumstances.

We recognize changes in estimated interest payable on net underpayments and overpayments of income taxes in interest expense and estimated penalties that may result from the settlement of some uncertain tax positions in other income. In our Consolidated Statements of Income for 2008, 2007 and 2006, we recognized reductions of interest expense of $4 million, $6 million and $1 million, respectively, and no penalties. At December 31, 2008, we had accrued $9 million for interest receivable and $2 million for interest payable and penalties. At December 31, 2007, we had accrued $5 million for interest receivable and $2 million for interest payable and penalties.

Deferred investment tax credits are amortized over the service lives of the properties giving rise to the credits.

At December 31, 2008, our Consolidated Balance Sheet included $3 million of prepaid state income taxes (recorded in prepayments), $6 million of federal and state income taxes payable (recorded in accrued interest, payroll and taxes) and $106 million of federal and state income taxes payable (recorded in deferred credits and other liabilities). At December 31, 2007, our Consolidated Balance Sheet included $136 million of prepaid federal and state income taxes (recorded in prepayments), $106 million of federal and state income taxes payable (recorded in deferred credits and other liabilities) and a $33 million receivable from Dominion for tax refunds (recorded in affiliated receivables).

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. At December 31, 2008 and 2007, accounts payable included $23 million and $31 million, respectively, of checks outstanding but not yet presented for payment. For purposes of our Consolidated Statements of Cash Flows, we consider cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

Derivative Instruments

We use derivative instruments such as futures, swaps, forwards, options and FTRs to manage the commodity, currency exchange, and financial market risks of our business operations.

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, requires all derivatives, except those for which an exception applies, to be reported in our Consolidated Balance Sheets at fair value. Derivative contracts representing unrealized gain positions and purchased options are reported as derivative assets. Derivative contracts representing unrealized losses and options sold are reported as derivative liabilities. One of the exceptions to fair value accounting normal purchases and normal sales may be elected when the contract satisfies certain criteria, including a requirement that physical delivery of the underlying commodity is probable. Expenses and revenues resulting from deliveries under normal purchase contracts and normal sales contracts, respectively, are included in earnings at the time of contract performance.

To manage price risk, we hold certain derivative instruments that are not designated as hedges for accounting purposes. However, to the extent we do not hold offsetting positions for such

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derivatives, we believe these instruments represent economic hedges that mitigate our exposure to fluctuations in commodity prices, interest rates and foreign exchange rates.

All income statement activity, including amounts realized upon settlement, for derivative contracts are presented in operating revenue, operating expense or interest and related charges based on the nature of the underlying risk. As previously discussed, under our former derivative income statement classification policy, this activity was presented in other operations and maintenance expense on a net basis. Following the revision of this policy in the fourth quarter of 2008, our prior year Consolidated Statements of Income were recast to conform to the 2008 presentation.

We generally recognize revenue or expense from all non-derivative energy-related contracts on a gross basis at the time of contract performance, settlement or termination.

Following the reapplication of SFAS No. 71, for jurisdictions subject to cost-based regulation, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities. Realized gains or losses on the derivative instruments subject to regulatory accounting are generally recognized when the related transactions impact earnings.

Derivative Instruments Designated as Hedging Instruments

We designate certain derivative instruments as either cash flow or fair value hedges for accounting purposes. For all derivatives designated as hedges, we formally document the relationship between the hedging instrument and the hedged item, as well as the risk management objective and the strategy for using the hedging instrument. We assess whether the hedging relationship between the derivative and the hedged item is highly effective at offsetting changes in cash flows or fair values both at the inception of the hedging relationship and on an ongoing basis. Any change in the fair value of the derivative that is not effective at offsetting changes in the cash flows or fair values of the hedged item is recognized currently in earnings. Also, we exclude certain gains or losses on hedging instruments from the measurement of hedge effectiveness, such as gains or losses attributable to changes in the time value of options or changes in the difference between spot prices and forward prices, thus requiring that such changes be recorded currently in earnings. We discontinue hedge accounting prospectively for derivatives that cease to be highly effective hedges.

Following the reapplication of SFAS No. 71, for jurisdictions subject to cost-based regulation, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities. Realized gains or losses on the derivative instruments are generally recognized when the related transactions impact earnings.

Cash Flow Hedges A portion of our hedge strategies represents cash flow hedges of the variable price risk associated with the purchase of natural gas, electricity and other energy-related products. We also use foreign currency forward and option contracts to hedge the variability in foreign exchange rates and interest rate swaps to hedge our exposure to variable interest rates on long-term debt. For transactions in which we are hedging the variability of cash flows, changes in the fair value of the derivative are

reported in AOCI, to the extent they are effective at offsetting changes in the hedged item. We reclassify derivative gains or losses reported in AOCI to earnings when the forecasted item is included in earnings, or earlier, if it becomes probable that the forecasted transaction will not occur. For cash flow hedge transactions, we discontinue hedge accounting if the occurrence of the forecasted transaction is determined to be no longer probable.

Fair Value Hedges We use designated interest rate swaps as fair value hedges on certain fixed-rate long-term debt to manage our interest rate exposure. For fair value hedge transactions, changes in the fair value of the derivative are generally offset currently in earnings by the recognition of changes in the hedged item s fair value. We reclassify derivative gains and losses from the hedged item to earnings when the hedged item is included in earnings, or earlier, if the hedged item no longer qualifies for hedge accounting. For fair value hedge transactions, we discontinue hedge accounting if the hedged item no longer qualifies for hedge accounting.

See Note 6 for further information about fair value measurements and associated valuation methods for derivatives under SFAS No. 157.

Investments

Marketable Equity And Debt Securities

We account for and classify investments in marketable equity and debt securities held by our nuclear decommissioning trusts as available-for-sale securities. These investments are reported at fair value in nuclear decommissioning trust funds in our Consolidated Balance Sheets. Upon reapplication of SFAS No. 71 in April 2007 for our utility generation operations, net realized and unrealized gains and losses (including any other-than-temporary impairments) on investments held in our utility nuclear decommissioning trusts are recorded to a regulatory liability for certain jurisdictions subject to cost-based regulation. We continue to report realized gains and losses (including any other-than-temporary impairments) for jurisdictions that are not subject to cost-based regulation in other income and unrealized gains as a component of AOCI, net of tax.

In determining realized gains and losses for marketable equity and debt securities, the cost basis of the security is based on the specific identification method.

Non-Marketable Investments

We account for illiquid and privately held securities for which market prices or quotations are not readily available under either the equity or cost method. Our non-marketable investments include:

- *Equity method investments* when we have the ability to exercise significant influence, but not control, over the investee. These investments are recorded in investments in other investments in our Consolidated Balance Sheets. We record equity method adjustments in other income in our Consolidated Statements of Income including: our proportionate share of investee income or loss, gains or losses resulting from investee capital transactions, and other adjustments required by the equity method.

- *Cost method investments* when we do not have the ability to exercise significant influence over the investee. These

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Notes to Consolidated Financial Statements, Continued

investments are included in other investments and nuclear decommissioning trust funds.

OTHER THAN TEMPORARY IMPAIRMENT

We periodically review our investments to determine whether a decline in fair value should be considered other than temporary. We use several criteria to evaluate other-than-temporary declines, including the length of time over which the market value has been lower than its cost, the percentage of the decline as compared to its cost and the expected fair value of the security. If a decline in fair value of any security is determined to be other than temporary, the security is written down to its fair value at the end of the reporting period. Our method of assessing other-than- temporary declines requires demonstrating the ability to hold individual securities for a period of time sufficient to allow for the anticipated recovery in their market value prior to the consideration of the other criteria mentioned above. Since we have limited ability to oversee the day-to-day management of our nuclear decommissioning trust fund investments, we do not have the ability to hold individual securities in the trusts through an anticipated recovery period. Accordingly, we consider all securities held by our nuclear decommissioning trusts with market values below their cost bases to be other-than temporarily impaired.

Property, Plant and Equipment

Property, plant and equipment, including additions and replacements, is recorded at original cost, consisting of labor, materials, and other direct and indirect costs such as asset retirement costs, capitalized interest and, for certain operations subject to cost-of-service rate regulation, AFUDC and overhead costs. The cost of repairs and maintenance, including minor additions and replacements, is charged to expense as it is incurred.

In 2008, 2007 and 2006, we capitalized interest costs and AFUDC of $21 million, $27 million and $21 million to property, plant and equipment, respectively. Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations in April 2007, we discontinued capitalizing interest on generation-related construction projects since the Virginia Commission previously allowed for current recovery of construction financing costs. Under current Virginia legislation, certain Virginia jurisdictional projects qualify for current recovery of AFUDC through rate adjustment clauses. AFUDC on these projects is calculated and recorded as a regulatory asset prior to implementation of the rate adjustment clause and is not capitalized to property, plant and equipment. In 2008 and 2007, we recorded $18 million and $1 million of AFUDC related to these projects, respectively.

For property subject to cost-of-service rate regulation, including electric distribution, electric transmission and utility generation property effective April 2007, the undepreciated cost of such property, less salvage value, is charged to accumulated depreciation at retirement with gains and losses recorded on sales of property. Cost of removal collections from utility customers and expenditures not representing AROs are recorded as regulatory liabilities.

For property that is not subject to cost-of-service rate regulation, including utility generation property prior to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations in April 2007, cost of removal not

associated with AROs is charged to expense as incurred. We also record gains and losses upon retirement based upon the difference between the proceeds received, if any, and the property s net book value at the retirement date.

Depreciation of property, plant and equipment is computed on the straight-line method based on projected service lives. Our depreciation rates on utility property, plant and equipment are as follows:

Year Ended December 31,	**2008**	2007	2006
(percent)			
Generation[1]	**2.60**	2.24	2.07
Transmission	**2.03**	1.98	1.97
Distribution	**3.37**	3.38	3.45
General and other	**3.97**	4.57	4.93

(1) In October 2007, we revised the depreciation rates for our generation assets to reflect the results of a new depreciation study, which incorporates the property, plant and equipment accounting policy changes that were made upon the reapplication of SFAS No. 71 as well as updates to other assumptions. This change increased annual depreciation expense by approximately $54 million ($33 million after tax).

Nuclear fuel used in electric generation is amortized over its estimated service life on a units-of-production basis. We report the amortization of nuclear fuel in electric fuel and energy purchases expense in our Consolidated Statements of Income and in depreciation and amortization in our Consolidated Statements of Cash Flows.

Emissions Allowances

Emissions allowances are issued by the EPA and permit the holder of the allowance to emit certain gaseous by-products of fossil fuel combustion, including SO_2 and NO_X. Allowances may be transacted with third parties or consumed as these emissions are generated. Allowances allocated to or acquired by our generation operations are held primarily for consumption and are classified as intangible assets in our Consolidated Balance Sheets. Carrying amounts are based on our cost to acquire the allowances. Allowances issued directly to us by the EPA are carried at zero cost.

Emissions allowances are amortized in the periods the emissions are generated, with the amortization reflected in depreciation and amortization expense in our Consolidated Statements of Income. We report purchases and sales of these allowances as investing activities in our Consolidated Statements of Cash Flows and gains or losses resulting from sales in other operations and maintenance expense in our Consolidated Statements of Income.

Impairment of Long-Lived and Intangible Assets

We perform 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. A long-lived or intangible asset is written down to fair value if the sum of its expected future undiscounted cash flows is less than its carrying amount.

Regulatory Assets and Liabilities

For utility operations subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, we defer these costs as regulatory assets that otherwise would be expensed by nonregulated companies. Likewise, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the period authorized by the regulator.

Asset Retirement Obligations

We recognize AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of future retirement activities to be performed. These amounts are capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, we estimate fair value using discounted cash flow analyses. With the reapplication of SFAS No. 71 for the Virginia jurisdiction of our generation operations in April 2007, we now report accretion of the AROs associated with nuclear decommissioning due to the passage of time as an adjustment to the related regulatory liability for certain jurisdictions. Previously, we reported such expense in other operations and maintenance expense in our Consolidated Statements of Income. We report accretion of all other AROs in other operations and maintenance expense in our Consolidated Statements of Income.

Amortization of Debt Issuance Costs

We defer and amortize debt issuance costs and debt premiums or discounts over the expected lives of the respective debt issues, considering maturity dates and, if applicable, redemption rights held by others. 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 are amortized over the lives of the new issues.

NOTE 3. NEWLY ADOPTED ACCOUNTING STANDARDS

2008

SFAS NO. 157

We adopted the provisions of SFAS No. 157, effective January 1, 2008. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 applies broadly to financial and non-financial assets and liabilities that are measured at fair value under other authoritative accounting pronouncements, but does not expand the application of fair value accounting to any new circumstances.

Generally, the provisions of this statement are applied prospectively. Certain situations, however, require retrospective application as of the beginning of the year of adoption through the recognition of a cumulative effect of accounting change. Such retrospective application was required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses under EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk*

Management Activities, and SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments*. Retrospective application did not result in a cumulative effect of accounting change in retained earnings as of January 1, 2008.

In February 2008, the FASB issued FSP FAS No. 157-1, *Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13*, which excludes leasing transactions from the scope of SFAS No. 157. However, the exclusion does not apply to fair value measurements of assets and liabilities recorded as a result of a lease transaction but measured pursuant to other pronouncements within the scope of SFAS

No. 157.

In February 2008, the FASB issued FSP FAS No. 157-2, *Effective Date of FASB Statement No. 157*, which delays the effective date of SFAS No. 157 by one year (to January 1, 2009) for non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). For the Company, this delays the effective date of SFAS No. 157 primarily for intangibles, property, plant and equipment and AROs.

In October 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,* which clarifies the application of SFAS No. 157 to financial assets in a market that is not active. This FSP was effective beginning in the third quarter of 2008 and affirms that SFAS No. 157 allows for the use of unobservable inputs in determining the fair value of a financial asset when relevant observable inputs do not exist or when observable inputs require significant adjustment based on unobservable data. This may be the case, for example, in an inactive or distressed market. This FSP did not have an impact on our results of operations or financial condition.

See Note 6 for further information on fair value measurements in accordance with SFAS No. 157.

SFAS NO. 159

The provisions of SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, became effective for us beginning January 1, 2008. SFAS No. 159 provides an entity with the option, at specified election dates, to measure certain financial assets and liabilities and other items at fair value, with changes in fair value recognized in earnings as those changes occur. SFAS No. 159 also establishes presentation and disclosure requirements that include displaying the fair value of those assets and liabilities for which the entity elected the fair value option on the face of the balance sheet and providing management s reasons for electing the fair value option for each eligible item. We have not elected the fair value option for any eligible items. Therefore, the provisions of SFAS No. 159 have not impacted our results of operations or financial condition.

FSP FIN 39-1

The provisions of FSP FIN 39-1 became effective for us beginning January 1, 2008. FSP FIN 39-1 amends FIN 39 to permit the offsetting of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. Upon our adoption of FSP FIN 39-1, we revised our accounting policy to no longer offset fair value amounts recognized for certain derivative instruments and recast our prior year Consolidated Balance Sheet in order to retrospectively apply the standard. The adoption of FSP FIN 39-1 resulted in a $6 million increase in both Other current assets and Other current liabilities as of December 31, 2007. FSP FIN 39-1 also requires disclosures related to our cash collateral, for which we had recorded margin assets of $18 million and margin liabilities of $4 million at December 31, 2008. The adoption of FSP FIN 39-1 had no impact on our results of operations or cash flows.

FSP FAS 140-4 AND FIN 46R-8

The provisions of FSP FIN FAS 140-4 and FIN 46R-8, *Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interest in Variable Interests Entities*, became effective for us for the year ended December 31, 2008. This FSP amends FASB Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, to require public entities to provide additional disclosures about transfers of financial assets. It also amends FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, to require public enterprises to provide additional disclosures about their involvement with variable interest entities. The provisions of FSP FIN FAS 140-4 and FIN 46R-8 have not impacted our results of operations or financial condition.

2007

FIN 48

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we recorded a $5 million benefit, primarily attributable to interest, to beginning retained earnings for the cumulative effect of the change in accounting principle. As of January 1, 2007, our unrecognized tax benefits totaled $225 million. For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility.

EITF 06-3

Effective January 1, 2007, EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*, requires certain disclosures if an entity collects and reports as revenue any tax assessed by a governmental authority that is both imposed on and concurrent with a specific revenue-producing transaction between the entity, as a seller, and its customers. We collect sales, consumption and consumer utility taxes but exclude such amounts from revenue.

NOTE 4. RECENTLY ISSUED ACCOUNTING STANDARDS

SFAS NO. 141R

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations*. SFAS No. 141R requires an acquirer to recognize the assets acquired, the liabilities assumed

and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS No. 141R also requires disclosure of information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS No. 141R requires that acquisition-related costs be expensed as incurred. SFAS No. 141R amends SFAS No. 109*,* to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141R further amends SFAS No. 109 and FIN 48, to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties and acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances. The provisions of SFAS No. 141R became effective for us on January 1, 2009.

SFAS NO. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*. SFAS No. 161 requires enhancements to disclosures regarding derivative instruments and hedging activities accounted for under SFAS No. 133. The enhancements include additional disclosures regarding the reasons derivative instruments are used, how they are used, how these instruments and their related hedged items are accounted for under SFAS No. 133, as well as the impact of these derivative instruments on an entity s results of operations, financial condition and cash flows. In addition, SFAS No. 161 requires the disclosure of the fair values of derivative instruments, and associated gains and losses in a tabular format and information about derivative features that are credit-risk related. The provisions of SFAS No. 161 will become effective for disclosures in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009.

NOTE 5. INCOME TAXES

Details of income tax expense were as follows:

Year Ended December 31, (millions)	**2008**	2007	2006
Current expense:			
Federal	**$ 158**	$ 152	$ 213
State	**37**	(37)	47
Total current	**195**	115	260
Deferred expense:			
Federal	**279**	163	29
State	**30**	103	10
Total deferred	**309**	266	39
Amortization of deferred investment tax credits	**(4)**	(10)	(15)
Total income tax expense	**$ 500**	$ 371	$ 284

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

Year Ended December 31,	**2008**	2007	2006
U.S statutory rate	**35.0%**	35.0%	35.0%
Increases (reductions) resulting from:			
State income tax, net of federal tax benefit	**3.6**	4.4	4.8
Amortization of investment tax credits	**(0.3)**	(0.8)	(1.5)
Domestic production activities deduction	**(0.5)**	(0.2)	
AFUDC equity	**(0.5)**	(0.5)	(0.3)
Legislative changes	**(0.4)**		
Employee benefits	**(0.2)**	(0.3)	(0.2)
Other, net		0.4	(0.5)
Effective tax rate	**36.7%**	38.0%	37.3%

As the result of West Virginia income tax rate reductions enacted in March 2008, to be phased in during the period 2009 through 2014, we reduced our net deferred tax liabilities by $6 million.

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. Our net deferred income taxes consist of the following:

As of December 31,	**2008**	2007
(millions)		
Deferred income taxes:		
Total deferred income tax assets	**$ 394**	$ 643
Total deferred income tax liabilities	**2,875**	2,824
Total net deferred income tax liabilities	**$ 2,481**	$ 2,181
Total deferred income taxes:		
Depreciation method and plant basis differences	**$ 2,087**	$ 1,980
Deferred state income taxes	**214**	185
Deferred fuel	**313**	151
Other	**(133)**	(135)
Total net deferred income tax liabilities	**$ 2,481**	$ 2,181

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret the laws differently. We are routinely audited by federal and state tax authorities. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material.

Prior to 2007, we established liabilities for income tax-related contingencies when we believed that it was probable that a liability had been incurred and the amount could be reasonably estimated and subsequently reviewed them in light of changing facts and circumstances.

With the adoption of FIN 48, effective January 1, 2007, we recognize in the financial statements only those positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information. If we take or expect to take a tax return position and any portion of the related tax benefit is not recognized in the financial statements, we disclose such amount as an unrecognized tax benefit. These unrecognized tax benefits may impact the financial statements by increasing taxes payable, reducing tax

refunds receivable or changing deferred taxes. Also, when uncertainty about the deductibility of an amount is limited to the timing of such deductibility, the increase in taxes payable (or reduction in tax refunds receivable) is accompanied by a decrease in deferred tax liabilities.

A reconciliation of changes in our unrecognized tax benefits follows:

(millions)	**2008**	2007
Balance at January 1,	**$ 195**	$ 225
Increases prior period positions	**20**	20
Decreases prior period positions	**(22)**	(36)
Current period positions	**20**	15
Prior period positions becoming otherwise deductible in current period	**(11)**	(13)
Settlement with tax authorities	**(22)**	(16)
Balance at December 31,	**$ 180**	$ 195

Unrecognized tax benefits that, if recognized, would affect the effective tax rate were $21 million and $8 million at December 31, 2008 and 2007, respectively, and $5 million at January 1, 2007. As the result of not recognizing these tax benefits, income tax expense increased by $13 million and $3 million in 2008 and 2007, respectively.

For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. When uncertainty about the deductibility of amounts is limited to the timing of such deductibility, any tax liabilities recognized for prior periods would be subject to offset with the availability of refundable amounts from later periods when such deductions would otherwise be taken. Pending resolution of these timing uncertainties, interest is being accrued until the period in which the amounts would become deductible.

For Dominion and its subsidiaries, the U.S. federal statute of limitations has expired for tax years prior to 1999, except that we have reserved the right to pursue refunds related to certain deductions for the years 1995 through 1998.

In 2007, the U.S. Congressional Joint Committee on Taxation completed its review of our settlement with the Appellate Division of the Internal Revenue Service (IRS Appeals) for tax years 1993 through 1998. In October of 2007, we received a tax refund of approximately $33 million for 1993 through 1997. Due to carryback adjustments, the tax refund of $5 million for 1998 will not be received until tax years 1999 through 2001 have been settled and reviewed by the Joint Committee. The refund will have no impact on our earnings.

We have reached a settlement with IRS Appeals regarding certain adjustments proposed during the examination of tax years 1999 through 2001, except we have reserved the right to pursue refunds related to certain deductions. The settlement is being submitted to the Joint Committee for review. With the settlement and payment of resulting tax liabilities, our unrecognized tax benefits would be reduced by approximately $12 million with no impact on our earnings. In addition, we would be entitled to a refund of $41 million, representing amounts paid during the examination and appeals process related to the adjustments disputed in our protest filed with IRS Appeals. The refund will have no impact on our earnings.

Notes to Consolidated Financial Statements, Continued

In 2007, the Internal Revenue Service (IRS) completed its examination of Dominion s 2002 and 2003 consolidated returns. We filed protests for certain proposed adjustments with IRS Appeals in July 2007, and Dominion is currently engaged in settlement negotiations with IRS Appeals regarding those adjustments. In addition, the IRS began its audit of tax years 2004 and 2005 in November 2007.

With our appeals of assessments received from tax authorities, including amounts related to the settlement negotiations with IRS Appeals for 2002 and 2003, we believe that it is reasonably possible that unrecognized tax benefits could decrease by $30 million to $70 million during 2009. The decrease would be the result of successful resolution of proposed adjustments through settlement negotiations or payments made to tax authorities. In addition, unrecognized tax benefits could be reduced by $13 million to recognize prior period amounts becoming otherwise deductible in the current period. Since the uncertainty for the majority of these unrecognized tax benefits involve only the timing of the deductions, we anticipate that the impact on earnings will be limited to revisions of our accrual for interest on tax underpayments and overpayments.

We are currently working with the IRS under its Pre-Filing Program (Program) to enter into an agreement regarding the calculation of our qualified production activities deduction. The objective of the Program is to provide taxpayers with greater certainty regarding a specific issue at an earlier point in time than can be attained under the normal post-filing examination process. If we are able to enter into an agreement with the IRS in 2009 that eliminates or reduces uncertainty about the deduction, it is reasonably possible that our unrecognized tax benefits as of December 31, 2008, could decrease by $5 million to $10 million, which would be reflected in our 2009 earnings.

Otherwise, with regard to tax years 2004 through 2008, we cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur in 2009.

Virginia Power is included in Dominion s combined state income tax returns. The returns filed with Virginia for 2005 and subsequent years remain subject to examination. We are also obligated to report adjustments resulting from IRS settlements of earlier years to state tax authorities. In addition, if we utilize state net operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are subject to examination by state tax authorities.

In February 2009, the President of the U.S. signed into law the American Recovery and Reinvestment Act of 2009 (the Act). The Act includes provisions to stimulate economic growth, including incentives for increased capital investment by businesses and incentives to promote renewable energy. We are currently evaluating the Act but have not yet determined its impact on our future results of operations, cash flows or financial condition.

NOTE 6. FAIR VALUE MEASUREMENTS

As described in Note 3, we adopted SFAS No. 157 effective January 1, 2008. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, SFAS No. 157 permits the

use of a mid-market pricing convention (the mid-point between bid and ask prices). SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of our own nonperformance risk on our liabilities. SFAS No. 157 also requires fair value measurements to assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). We apply fair value measurements to certain assets and liabilities, including commodity and interest rate derivative instruments, and nuclear decommissioning trust and other investments in accordance with the requirements described above. We apply credit adjustments to our derivative fair values in accordance with the requirements described above. These credit adjustments are currently not material to the derivative fair values.

In accordance with SFAS No. 157, we maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, we seek price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, or if we believe that observable pricing is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases, we must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis that reflects our market assumptions.

For options and contracts with option-like characteristics where observable pricing information is not available from external sources, we generally use a modified Black-Scholes Model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. We use other option models under special circumstances, including a Spread Approximation Model, when contracts include different commodities or commodity locations and a Swing Option Model, when contracts allow either the buyer or seller the ability to exercise within a range of quantities. For contracts with unique characteristics, we may estimate fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. For individual contracts, the use of different valuation models or assumptions could have a significant effect on the contract s estimated fair value.

We also utilize the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value, into three broad levels:

Level 1 Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as the majority of exchange-traded derivatives and listed equities and Treasury securities held in nuclear decommissioning trust funds.

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Level 2 Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 primarily include non-exchange traded derivatives such as over-the-counter commodity forwards and swaps, interest rate swaps, foreign currency forwards and options, and municipal bonds and short-term debt securities held in nuclear decommissioning trust funds.

Level 3 Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 consist of long-dated commodity derivatives, FTRs, and other modeled commodity derivatives.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

Fair value measurements are categorized as Level 3 when a significant amount of price or other inputs that are considered to be unobservable are used in their valuations. Long-dated commodity derivatives are based on unobservable inputs due to the length of time to settlement and absence of market activity and are therefore categorized as Level 3. FTRs are categorized as Level 3 fair value measurements because the only relevant pricing available comes from PJM auctions, which is accurate for day-one valuation, but generally is not considered to be representative of the ultimate settlement values. Other modeled commodity derivatives have unobservable inputs in their valuation, mostly due to non-transparent and illiquid markets.

As of December 31, 2008, our net balance of commodity derivatives categorized as Level 3 fair value measurements was a net liability of $69 million. A hypothetical 10% increase in commodity prices would decrease the net liability by $3 million, while a hypothetical 10% decrease in commodity prices would increase the net liability by $3 million.

SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy and requires a separate reconciliation of fair value measurements categorized as Level 3. The following table presents our assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions, as of December 31, 2008:

(millions)	Level 1	Level 2	Level 3	Total
Assets:				
Derivatives	**$**	**$ 60**	**$ 7**	**$ 67**
Investments	**225**	**714**		**939**
Total assets	**$ 225**	**$ 774**	**$ 7**	**$ 1,006**
Liabilities:				
Derivatives	**$**	**$ 23**	**$ 76**	**$ 99**

The following table presents the net change in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category for the year ended December 31, 2008:

(millions)	Derivatives (1)
Year Ended December 31, 2008	
Balance at January 1, 2008	**$ (4)**
Total realized and unrealized gains or (losses):	
Included in earnings	**(27)**
Included in other comprehensive income (loss)	
Included in regulatory and other assets/liabilities	**(59)**
Purchases, issuances and settlements	**21**

Transfers out of Level 3		
Balance at December 31, 2008	**$**	**(69)**
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	**$**	**(5)**

(1) Derivative assets and liabilities are presented on a net basis.

The gains and losses included in earnings in the Level 3 fair value category, including those attributable to the change in unrealized gains and losses relating to assets still held at the reporting date, were classified in Electric Fuel and Energy Purchases expense in our Consolidated Statement of Income for the year ended December 31, 2008.

Fair Value of Financial Instruments

Substantially all of our financial instruments are recorded at fair value, with the exception of the instruments described below that are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. At December 31, 2008 and 2007, the carrying amount of our cash and cash equivalents, customer and other receivables, short-term debt and accounts payable are representative of fair value because of the short-term nature of these instruments. The financial instruments carrying amounts and fair values are as follows:

At December 31,		**2008**		2007
(millions)	**Carrying Amount**	**Estimated Fair Value(1)**	Carrying Amount	Estimated Fair Value(1)
Long-term debt(2)	**$ 6,125**	**$ 6,231**	$ 5,190	$ 5,209
Junior subordinated notes payable to affiliated trust			412	402
Preferred stock(3)	**257**	**231**	257	257

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

(2) Includes securities due within one year and amounts which represent the unamortized discount and premium. Also includes the valuation of certain fair value hedges associated with our fixed rate debt of $1 million at December 31, 2008.

(3) Includes issuance expenses of $2 million at December 31, 2008 and 2007.

NOTE 7. HEDGE ACCOUNTING ACTIVITIES

We are exposed to the impact of market fluctuations in the price of electricity, natural gas and other energy-related products, as well as currency exchange and interest rate risks of our business

Notes to Consolidated Financial Statements, Continued

operations. We use derivative instruments to manage our exposure to these risks and designate derivative instruments as cash flow or fair value hedges for accounting purposes as allowed by SFAS No. 133. As discussed in Note 2, for jurisdictions subject to cost-based regulation, changes in the fair value of derivatives designated as hedges are deferred as regulatory assets or regulatory liabilities until the related transactions impact earnings.

For the years ended December 31, 2008, 2007 and 2006, gains or losses on hedging instruments determined to be ineffective and excluded from the measurement of effectiveness were not material. Amounts excluded from the measurement of ineffectiveness include gains or losses attributable to changes in the time value of options and changes in the differences between spot prices and forward prices.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in our Consolidated Balance Sheet at December 31, 2008:

(millions)	AOCI After Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months After Tax	Maximum Term
Electric capacity	$ 5	$ 3	41 months
Other	(1)	(2)	360 months
Total	$ 4	$ 1	

The amounts that will be 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 and will vary from the expected amounts presented above as a result of changes in market prices, interest rates and foreign exchange rates.

NOTE 8. INVESTMENTS

Marketable Equity and Debt Securities

We hold marketable equity and debt securities and cash equivalents in nuclear decommissioning trust funds to fund future decommissioning costs for our nuclear plants. Our decommissioning trust funds, as of December 31, 2008 and 2007, are summarized below. There were no unrealized losses included in AOCI as of December 31, 2008 or 2007.

	Fair	Total

(millions)	Value	Unrealized Gains
2008		
Equity securities	**$ 468**	**$ 9**
Debt securities	**460**	**17**
Cash equivalents and other	**17**	
Total	**$ 945**	**$ 26**(1)
2007		
Equity securities	$ 844	$ 245
Debt securities	468	13
Cash equivalents and other	27	
Total	$ 1,339	$ 258(1)

(1) Included in AOCI and the decommissioning trust regulatory liability as discussed in Note 2.

The fair values of debt securities within the nuclear decommissioning trust funds at December 31, 2008 by contractual maturity are as follows:

(millions)	Amount
Due in one year or less	**$ 27**
Due after one year through five years	**113**
Due after five years through ten years	**153**
Due after ten years	**167**
Total	**$ 460**

Gross realized gains on our available-for-sale securities totaled $45 million, $52 million and $49 million in 2008, 2007 and 2006, respectively, and gross realized losses totaled $143 million, $52 million and $33 million in 2008, 2007 and 2006, respectively. Gross realized gains and losses for 2008 and 2007 include amounts recorded to a regulatory liability as discussed in Note 2. In determining realized gains and losses, the cost of these securities was determined on a specific identification basis.

Cost-Method Investments

At December 31, 2008, the carrying value of our cost-method investments totaled $108 million, which approximated their estimated fair value. We did not have any significant cost-method investments at December 31, 2007.

NOTE 9. PROPERTY, PLANT AND EQUIPMENT

Major classes of property, plant and equipment and their respective balances are:

At December 31, (millions)	**2008**	2007
Utility:		
Generation	**$ 10,949**	$ 10,237
Transmission	**2,116**	1,942
Distribution	**7,250**	6,931
Nuclear fuel	**943**	930
General and other	**562**	591
Other including plant under construction	**1,648**	1,200
Total utility	**23,468**	21,831
Nonutility other	**8**	7

Total property, plant and equipment	**$ 23,476**	$ 21,838

Jointly-Owned Plants

Our proportionate share of jointly-owned plants at December 31, 2008 is as follows:

(millions, except percentages)	Bath County Pumped Storage Station	North Anna Power Station	Clover Power Station
Ownership interest	**60.0%**	**88.4%**	**50.0%**
Plant in service	**$ 1,011**	**$ 2,107**	**$ 560**
Accumulated depreciation	**(427)**	**(1,028)**	**(155)**
Nuclear fuel		**436**	
Accumulated amortization of nuclear fuel		**(343)**	
Other including plant under construction	**9**	**154**	**1**

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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. We report our share of operating costs in the appropriate operating expense (electric fuel and energy purchases, other operations and maintenance, depreciation and amortization and other taxes, etc.) in our Consolidated Statements of Income.

NOTE 10. INTANGIBLE ASSETS

All of our intangible assets are subject to amortization over their estimated useful lives. Amortization expense for intangible assets was $28 million, $46 million and $37 million for 2008, 2007 and 2006, respectively. In 2008, we acquired $22 million of intangible assets, primarily representing software and emissions allowances, with an estimated weighted-average amortization period of 6.55 and 8.19 years, respectively. The components of our intangible assets are as follows:

At December 31,		2008		2007
	Gross Carrying Amount	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
(millions)				
Software and software licenses	**$ 261**	**$ 157**	$ 240	$ 165
Emissions allowances	**72**	**4**	75	15
Other	**51**	**13**	53	12
Total	**$ 384**	**$ 174**	$ 368	$ 192

Annual amortization expense for these intangible assets is estimated to be $27 million for 2009, $29 million for 2010, $17 million for 2011, $12 million for 2012 and $6 million for 2013.

NOTE 11. REGULATORY ASSETS AND LIABILITIES

Our regulatory assets and liabilities include the following:

At December 31,	2008	2007
(millions)		
Regulatory assets:		
Deferred cost of fuel used in electric generation[1]	**$ 133**	$
Derivatives[2]	**79**	
Regulatory assets current	**212**	
Deferred cost of fuel used in electric generation[1]	**676**	386
RTO start-up costs and administration fees[3]	**122**	95
Income taxes recoverable through future rates[4]	**35**	30

AFUDC(5)	**19**	1
Termination of certain power purchase agreements(6)	**18**	20
Other	**51**	32
Regulatory assets non-current	**921**	564
Total regulatory assets	**$ 1,133**	$ 564
Regulatory liabilities:		
Provision for future cost of removal(7)	**$ 506**	$ 453
Decommissioning trust(8)	**213**	487
Other(9)	**61**	69
Total regulatory liabilities	**$ 780**	$ 1,009

(1) As discussed under Virginia Fuel Expenses in Note 20, in June 2007, the Virginia Commission approved a fuel factor increase of approximately $219 million, effective July 1, 2007 with the balance of approximately $443 million to be deferred and subsequently recovered, without interest, during the period commencing July 1, 2008 and ending June 30, 2011. Beginning July 1, 2008 the recovery of $231 million of the approximately $697 million prior year under-recovered fuel balance commenced, with the balance to be recovered in subsequent periods as provided by Virginia law.

(2) As discussed under Derivative Instruments in Note 2 for jurisdictions subject to cost-based regulation, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities as they are expected to be recovered from or refunded to customers, without interest.

(3) The FERC has approved our recovery of start-up costs incurred in connection with joining an RTO and on-going administrative charges paid to PJM through a DRC. We have deferred $97 million in start-up costs and administrative charges and $25 million of associated carrying costs. We expect recovery from Virginia jurisdictional retail customers to commence on the effective date of approval by the Virginia Commission of a rate adjustment clause designed to recover retail transmission costs as authorized under the 2007 Virginia Regulation Act.

(4) Amounts to be recovered through future rates to pay income taxes that become payable when rate revenue is provided to recover AFUDC-equity and depreciation of property, plant and equipment for which deferred income taxes were not recognized for ratemaking purposes, including amounts attributable to tax rate changes.

(5) Under current Virginia legislation, certain Virginia jurisdictional projects qualify for current recovery of AFUDC through rate adjustment clauses. AFUDC on these projects is calculated and recorded as a regulatory asset prior to implementation of the rate adjustment clause. The majority of this AFUDC is expected to be recovered through April 2012.

(6) The North Carolina Commission has authorized the deferral of previously incurred costs associated with the termination of certain long-term power purchase agreements with nonutility generators. The related costs are being amortized over the original term of each agreement.

(7) Rates charged to customers by our regulated business include a provision for the cost of future activities to remove assets that are expected to be incurred at the time of retirement.

(8) Primarily reflects a regulatory liability established in 2007 representing amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our utility nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143.

(9) Includes $20 million reported in other current liabilities in 2008.

At December 31, 2008, approximately $739 million of our regulatory assets represented past expenditures on which we do not earn a return. These expenditures consist primarily of deferred fuel costs and the cost of terminating certain power purchase agreements.

NOTE 12. ASSET RETIREMENT OBLIGATIONS

Our AROs are primarily associated with the decommissioning of our nuclear generation facilities. We also have AROs related to certain electric transmission and distribution assets located on property that we do not own and hydroelectric generation facilities. We currently do not have sufficient information to estimate a reasonable range of expected retirement dates for any of these assets. Thus, AROs for these assets will not be reflected in our Consolidated Financial Statements until sufficient information becomes available to determine a reasonable estimate of the fair value of the activities to be performed. Generally, this will occur when the expected retirement or abandonment dates are

Notes to Consolidated Financial Statements, Continued

determined by our operational planning. The changes to our AROs during 2008 were as follows:

(millions)	Amount
AROs at December 31, 2007(1)	$ 679
Obligations settled during the period	**(1)**
Accretion	**38**
Other	**1**
AROs at December 31, 2008(1)	**$ 717**

(1) Includes $1 million and $2 million reported in other current liabilities at December 31, 2007 and 2008, respectively.

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2008 and 2007, the aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $1.1 billion and $1.3 billion, respectively.

Note 13. Variable Interest Entities

FIN 46R addresses the consolidation of variable interest entities (VIEs). An entity is considered a VIE under FIN 46R if it does not have sufficient equity to finance its activities without assistance from variable interest holders or if its equity investors lack any of the following characteristics of a controlling financial interest:

- control through voting rights,
- the obligation to absorb expected losses, or
- the right to receive expected residual returns.

FIN 46R requires the primary beneficiary of a VIE to consolidate the VIE and to disclose certain information about its significant variable interests in the VIE. The primary beneficiary of a VIE is the entity that receives the majority of a VIE s expected losses, expected residual returns, or both.

We have long-term power and capacity contracts with four non-utility generators with an aggregate generation capacity of approximately 940 Mw. These contracts contain certain variable pricing mechanisms in the form of partial fuel reimbursement that we consider to be variable interests. After an evaluation of the information provided to us by these entities, we were unable to determine whether they were VIEs. However, the information they provided, as well as our knowledge of generation facilities in Virginia, enabled us to conclude that, if they were VIEs, we would not be the primary beneficiary. This conclusion was based primarily on a qualitative assessment of our variable interests as compared to the operations, commodity price and other risks retained by the equity and debt holders during the remaining terms of our contracts and for the years the entities are expected to operate after our contractual relationships expire. The contracts expire at various dates ranging from 2015 to 2021. We are not subject to any risk of loss from these potential VIEs other than our remaining purchase commitments which totaled $1.9 billion as of December 31, 2008. We paid $205 million, $211 million and $214 million for electric capacity and $196 million, $160 million and $130 million for electric energy to these entities for the years ended December 31, 2008, 2007 and 2006, respectively.

We purchased shared services from DRS, an affiliated VIE, of approximately $397 million, $344 million and $310 million for

the years ended December 31, 2008, 2007 and 2006, respectively. We determined that we are not the most closely associated entity with DRS and therefore not the primary beneficiary. DRS provides accounting, legal, finance and certain administrative and technical services to all

Dominion subsidiaries, including us. We have no obligation to absorb more than our allocated share of DRS costs.

Note 14. Short-Term Debt and Credit Agreements

We use short-term debt, primarily commercial paper, to fund working capital requirements and as a bridge to long-term debt financing. The level of our borrowings may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations.

Our credit facility commitments are with a large consortium of banks, including Lehman. In September 2008, Lehman filed for protection under Chapter 11 of the federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York. At December 31, 2008, Lehman s total commitment to our credit facilities was less than six percent of the aggregate commitment from the consortium of banks. We do not believe that the potential reduction in available capacity under these credit facilities that could result from Lehman s bankruptcy will have a significant impact on our liquidity.

Excluding commitments provided by Lehman, our short-term financing is supported by a $2.8 billion five-year joint revolving credit facility with Dominion dated February 2006, which is scheduled to terminate in February 2011. This credit facility is being used for working capital, as support for the combined commercial paper programs of Dominion and us and for other general corporate purposes. This credit facility can also be used to support up to $1.5 billion of letters of credit.

At December 31, 2008, total outstanding commercial paper supported by the joint credit facility was $297 million, all of which were our borrowings, with a weighted-average interest rate of 5.92%. At December 31, 2007, total outstanding commercial paper supported by the joint credit facility was $757 million, of which our borrowings were $257 million, with a weighted-average interest rate of 5.68%.

At December 31, 2008, total outstanding letters of credit supported by the joint credit facility were $187 million, of which less than $86 million were issued on our behalf. At December 31, 2007, total outstanding letters of credit supported by the joint credit facility were $229 million, of which less than $8 million were issued on our behalf.

At December 31, 2008, capacity available under the joint credit facility was approximately $2.4 billion.

In addition to the credit facility commitments of $2.8 billion disclosed above, we also have a $182 million five-year credit facility, excluding commitments provided by Lehman, that supports certain of our tax-exempt financings.

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NOTE 15. LONG-TERM DEBT

At December 31, (millions, except percentages)	2008 Weighted-Average Coupon(1)	2008	2007
Unsecured Senior and Medium-Term Notes:			
4.5% to 5.73%, due 2008 to 2013	**4.87%**	**$ 1,230**	$ 1,350
5.25% to 8.875%, due 2015 to 2038	**6.37%**	**4,272**	2,985
Unsecured Callable and Puttable Enhanced Securities[SM], 4.10% due 2038(2)			225
Tax-Exempt Financings(3):			
Variable rate, due 2008			60
Variable rates, due 2015 to 2027	**2.05%**	**119**	137
5.25% to 7.65%, due 2008 to 2010	**5.54%**	**112**	205
3.6% to 6.5%, due 2017 to 2035	**5.13%**	**393**	223
Notes Payable to Affiliates:			
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.375%, due 2042(4)			412
		6,126	5,597
Fair value hedge valuation(5)		**1**	
Amounts due within one year(6)	**5.76%**	**(125)**	(286)
Unamortized discount and premium, net		**(2)**	5
Total long-term debt		**$ 6,000**	$ 5,316

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2008.
(2) On December 15, 2008, option holders did not exercise their rights to purchase and remarket the notes. As a result, the notes were redeemed at par plus accrued interest, and we recorded a $23 million benefit from the early redemption of these securities.
(3) These financings relate to certain pollution control equipment at our generating facilities. The variable rate tax-exempt financings are supported by a stand-alone $182 million five-year credit facility, excluding commitments provided by Lehman, that terminates in February 2011.
(4) On May 19, 2008, the notes were redeemed at par plus accrued and unpaid distributions.
(5) Represents the valuation of certain fair value hedges associated with our fixed rate debt.
(6) Includes approximately $1 million for fair value hedge valuation for 2008.

Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2008 were as follows:

(millions)	2009	2010	2011	2012	2013	Thereafter	Total
	$ 124	**$ 246**	**$ 15**	**$ 616**	**$ 418**	**$ 4,707**	**$ 6,126**

Our short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2008, there were no events of default under our covenants.

Junior Subordinated Notes Payable to Affiliated Trust

In 2002, we established a subsidiary capital trust, Virginia Power Capital Trust II (trust), a finance subsidiary of which we held 100% of the voting interests. The trust sold 16 million 7.375% trust preferred securities for $400 million, representing preferred beneficial interests and 97% 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% beneficial ownership interest in the assets held by the capital trust, we issued $412 million of 2002 7.375% junior subordinated notes (junior subordinated notes) due July 30, 2042. The junior subordinated notes constituted 100% of the trust s assets.

In May 2008, we repaid $412 million 7.375% unsecured Junior Subordinated Notes and redeemed all 16 million units of the $400 million 7.375% Virginia Power Capital Trust II preferred securities due July 30, 2042. These securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions.

NOTE 16. PREFERRED STOCK

We are authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference, and had 2.59 million preferred shares outstanding as of December 31, 2008 and 2007. Upon involuntary liquidation, dissolution or winding-up of the Company, each share would be entitled to receive $100 plus accrued dividends. Dividends are cumulative.

Holders of the outstanding preferred stock 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).

Presented below are the series of preferred stock not subject to mandatory redemption that were outstanding as of December 31, 2008:

Dividend	Issued and Outstanding Shares (thousands)	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**	**101.77**(1)
6.98	**600**	**101.75**(2)
Flex MMP 12/02, Series A	**1,250**	**100.00**(3)
Total	**2,590**	

(1) Through 7/31/2009; $101.41 commencing 8/1/2009; amounts decline in steps thereafter to $100.00 by 8/1/2013.
(2) Through 8/31/2009; $101.40 commencing 9/1/2009; amounts decline in steps thereafter to $100.00 by 9/1/2013.
(3) Dividend rate was 5.50% through 12/20/2007. Dividend rate is now 6.25% through 3/20/2011; after which, the rate will be determined according to periodic auctions for periods established by us at the time of the auction process.

NOTE 17. SHAREHOLDER S EQUITY

Common Shareholder s Equity

In December 2008, as approved by the Virginia Commission, we issued 11,786 shares of our common stock to Dominion reflecting the conversion of $350 million of short-term demand note borrowings from Dominion to equity.

Notes to Consolidated Financial Statements, Continued

Other Paid-In Capital

In December 2007, we recorded contributed capital of $220 million reflecting the conversion of a $220 million note payable to Dominion to equity.

Accumulated Other Comprehensive Income

Presented in the table below is a summary of AOCI by component:

At December 31, (millions)	**2008**	2007
Net unrealized gains on derivatives hedging activities, net of $(3) and $(5) tax, respectively	**$ 4**	$ 7
Net unrealized gains on nuclear decommissioning trust funds, net of $(1) and $(14) tax, respectively	**1**	22
Total AOCI	**$ 5**	$ 29

NOTE 18. DIVIDEND RESTRICTIONS

The Virginia Commission may prohibit any public service company from declaring or paying a dividend to an affiliate, if found to be detrimental to the public interest. At December 31, 2008, the Virginia Commission had not restricted our payment of dividends.

Certain agreements associated with our joint credit facility with Dominion contain restrictions on the ratio of our debt to total capitalization. These limitations did not restrict our ability to pay dividends to Dominion at December 31, 2008.

NOTE 19. EMPLOYEE BENEFIT PLANS

We participate 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, we are 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 (ERISA). Our net periodic pension cost related to this plan was $32 million, $37 million and $63 million in 2008, 2007 and 2006, respectively. Employee compensation is the basis for determining our share of total pension costs. We did not contribute to the pension plan in 2008, 2007 or 2006.

We participate in plans that provide certain retiree health care and life insurance benefits to multiple Dominion subsidiaries. Annual employee premiums are based on several factors such as age, retirement date and years of service. Our net periodic benefit cost related to these plans was $33 million, $24 million and $37 million in 2008, 2007 and 2006, respectively. Employee headcount is the basis for determining our share of total benefit costs.

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, we fund other postretirement benefit costs through a Voluntary Employees Beneficiary Association (VEBA). Our contributions to the VEBA were $15 million, $7 million and $24 million in 2008, 2007 and 2006, respectively. We expect to contribute $35 million to the VEBA in 2009.

Dominion holds investments in trusts to fund benefit payments for the employee pension and other postretirement benefit plans, in which our employees participate. Investment-related declines in these trusts, such as those experienced during 2008, will result in future increases in the periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash that we will provide to Dominion for our share of employee benefit plan contributions.

We also participate in Dominion-sponsored employee savings plans that cover substantially all employees. Employer matching contributions of $14 million, $12 million and $11 million were incurred in 2008, 2007 and 2006, respectively.

NOTE 20. COMMITMENTS AND CONTINGENCIES

As the result of issues generated in the ordinary course of business, we are involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies, some of which involve substantial amounts of money. The ultimate outcome of such proceedings cannot be predicted at this time, however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on our financial position, liquidity or results of operations.

Long-Term Purchase Agreements

At December 31, 2008, we had the following long-term commitments that are noncancelable or are cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services:

(millions)	2009	2010	2011	2012	2013	Thereafter	Total
Purchased electric capacity(1)	**$ 361**	**$ 350**	**$ 349**	**$ 354**	**$ 356**	**$ 1,499**	**$ 3,269**

(1) Commitments represent estimated amounts payable for capacity under power purchase contracts with qualifying facilities and independent power producers, the last of which ends in 2021. Capacity payments under the contracts are generally based on fixed dollar amounts per month, subject to escalation using broad-based economic indices. At December 31, 2008, the present value of our total commitment for capacity payments is $2.2 billion. Capacity payments totaled $379 million, $410 million and $437 million, and energy payments totaled $372 million, $360 million and $291 million for 2008, 2007, and 2006, respectively.

Lease Commitments

We lease various facilities, vehicles and equipment primarily under operating leases. The lease agreements expire on various dates and certain of the leases are renewable and contain options to purchase the leased property. Payments under certain leases are escalated based on an index such as the Consumer Price Index. Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2008 are as follows:

(millions)	2009	2010	2011	2012	2013	Thereafter	Total
	$ 27	**$ 24**	**$ 20**	**$ 13**	**$ 9**	**$ 22**	**$ 115**

Rental expense totaled $39 million, $37 million and $34 million for 2008, 2007 and 2006, respectively, the majority of which is reflected in other operations and maintenance expense.

Environmental Matters

We are 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.

Superfund Sites

From time to time, we may be identified as a PRP 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, we 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. We do not believe that any currently identified sites will result in significant liabilities.

Nuclear Operations

Nuclear Decommissioning   Minimum Financial Assurance

The NRC requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Our 2008 calculation for the NRC minimum financial assurance amount, aggregated for our nuclear units, was $1.5 billion and has been satisfied by a combination of the funds being collected and deposited in the nuclear decommissioning trusts and the real annual rate of return growth of the funds allowed by the NRC. While the current economic downturn has resulted in a decrease in the value of investments held by our nuclear decommissioning trusts, we continue to believe that the amounts currently available in our decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for our Surry and North Anna units particularly when combined with ratepayer collections and contributions to the decommissioning trusts, if such future collections and contributions are required. This reflects our long-term investment horizon since the units will not be decommissioned for decades and our positive long-term outlook for trust fund investment returns. We will continue to monitor these trusts to ensure they meet the minimum financial assurance requirement, which may include the use of parent company guarantees, surety bonding or other financial guarantees recognized by the NRC.

Nuclear Insurance

The Price-Anderson Act provides the public up to $12.5 billion of liability protection per nuclear incident via obligations required of owners of nuclear power plants. The Price-Anderson Act Amendment of 1988 allows for an inflationary provision adjust-

ment every five years. We have purchased $300 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 U.S., we could be assessed up to $118 million for each of our four licensed reactors, not to exceed $18 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 was renewed again in 2005.

Our current level of property insurance coverage ($2.55 billion each for North Anna and 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. Our 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 $49 million. Based on the severity of the incident, the board of directors of our nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. We have 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.

We purchase 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, we are 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.

ODEC, a part owner of North Anna, is responsible to us 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.

Spent Nuclear Fuel

Under provisions of the Nuclear Waste Policy Act of 1982, we have entered into a contract with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by our contract with the DOE. In January 2004, we filed a lawsuit in the U.S. Court of Federal Claims against the DOE requesting damages in connection with its failure to commence accepting spent nuclear fuel. A trial occurred in May 2008 and post-trial briefing and argument concluded in July 2008. On October 15, 2008, the Court issued an opinion and order for the Company in the amount of approximately $112 million for its spent-fuel related costs through June 30, 2006, and judgment was entered by the Court on October 28, 2008. On December 24, 2008, the government appealed the judgment to the U.S. Court of Appeals for the Federal Circuit and the appeal was docketed on December 30, 2008. Briefing on the appeal is expected to take place in 2009. Payment of any damages will not occur until the appeal process has been resolved. We cannot predict the outcome

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Notes to Consolidated Financial Statements, Continued

of this matter; however, in the event that we recover damages, such recovery, including amounts attributable to joint owners, is not expected to have a material impact on our results of operations. We will continue to manage our spent fuel until it is accepted by the DOE.

Litigation

We are co-owners with ODEC of the Clover power station. In 1989, we entered into a long term coal transportation agreement with Norfolk Southern Railway Company (Norfolk Southern) for the delivery of coal to the facility. The agreement specifies a base rate with adjustments tied to a published index. Norfolk Southern claimed in October 2003 that the parties to the agreement had employed an incorrect reference index since the agreement s inception to adjust the base transportation rate. In November 2003, we and ODEC filed suit against Norfolk Southern seeking to clarify the price adjustment provisions of the transportation agreement. The trial court ruled in Norfolk Southern s favor by

concluding that the agreement specifies the use of the index (NS Index) which Norfolk Southern claims should have been applied to adjust the base rate and which should be applied going forward. On September 1, 2006, the court entered an order directing us and ODEC to correct invoices from December 1, 2003 to the present by calculating rates using the NS Index as if it had been applied from the inception of the agreement, to tender the difference to Norfolk Southern with interest at the rate provided by the agreement and to pay future invoices using the NS Index as if it had been applied from the inception of the agreement.

In April 2008, issues regarding the amount of Norfolk Southern s claimed damages were tried, and the trial court issued a Final Order and Decree. The court assessed damages of approximately $78 million for the contract period from December 1, 2003 through November 30, 2007 and imposed prejudgment interest of approximately $9 million. If upheld, our share would be one-half of the total judgment, approximately $44 million. The court also ordered the Company and ODEC to calculate base rate adjustments using the NS Index for the remaining term of the agreement. Interest would be assessed on any difference between the amounts which we and ODEC pay to Norfolk Southern and the amounts which the court ordered to be paid. We believe the court s interpretation of the transportation agreement, and its ruling on other issues in the case, are legally incorrect. In July 2008, we and ODEC filed a petition for appeal of the trial court s order to the Supreme Court of Virginia and posted security to suspend execution of the judgment during the appeal. In January 2009, the Supreme Court of Virginia granted our petition for appeal. No liability has been recorded in our Consolidated Financial Statements related to this matter.

Guarantees and Surety Bonds

As of December 31, 2008, we had issued $16 million of guarantees primarily to support tax exempt debt issued through conduits. We had also purchased $109 million of surety bonds for various purposes, including providing workers compensation coverage. Under the terms of surety bonds, we are 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, we 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. We are unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate us have not yet occurred or, if any such event has occurred, we have not been notified of its occurrence. However, at December 31, 2008, we believe future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

Status of Electric Regulation in Virginia

2007 Virginia Regulation Act And Fuel Factor Amendments

On July 1, 2007, legislation amending the Virginia Electric Utility Restructuring Act (the Regulation Act) and the fuel factor statute became effective, which significantly changed electricity regulation in Virginia. Prior to the Regulation Act, our base rates in Virginia were to be capped at 1999 levels until December 31, 2010, at which time Virginia was to convert to retail competition for its electric supply service. The Regulation Act ended capped rates two years early, on December 31, 2008, at which time retail competition would be available only to individual retail customers with a demand of more than 5 Mw and non-residential retail customers who obtain Virginia Commission approval to aggregate their load to reach the 5 Mw threshold. Individual retail customers will also be permitted to purchase renewable energy from competitive suppliers if their incumbent electric utility does not offer a 100% renewable energy tariff.

Pursuant to the Regulation Act, the Virginia Commission entered an order in January 2009 initiating reviews of the base rates and terms and conditions of all investor-owned utilities in Virginia. The Company must submit its filing and accompanying schedules on or before April 1, 2009, and it anticipates that its filing will support an increase in base rates. The ROE in that rate review will be no lower than that reported by not less than a majority of comparable utilities within the southeastern U.S., with certain limitations, as described in the Act. Possible outcomes of the 2009 rate review, according to the Regulation Act, include a rate increase, a rate decrease, and a refund of earnings more than 50 basis points above the authorized ROE. We are unable to predict the outcome of future rate actions at this time. However, an unfavorable outcome could adversely affect our results of operations, financial condition and cash flows.

After the 2009 rate review, the Virginia Commission will conduct biennial reviews of our rates, terms and conditions beginning in 2011. As in the 2009 rate review, our ROE in the biennial reviews can be no lower than that reported by not less than a majority of comparable utilities within the southeastern U.S., with certain limitations, as described in the Act. The Commission shall be authorized to increase our base rates if our earnings are more than 50 basis points below the authorized level.

If our earnings are more than 50 basis points above the authorized level, such earnings will be shared with customers. If over-earning persists for two consecutive biennial periods, in addition to earnings sharing, rates may also be reduced.

Separate from base rates, the Regulation Act also authorizes stand-alone rate adjustment clauses for recovery of costs for new generation projects, environmental compliance, FERC-approved transmission costs, conservation and energy efficiency programs, and renewables programs. The Act also provided for enhanced returns on capital expenditures on specific new generation projects, including but not limited to nuclear generation, clean coal/carbon capture compatible generation, and renewable generation projects.

The Regulation Act also continues statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter, as discussed in *Virginia Fuel Expenses*.

Virginia Fuel Expenses

Under amendments to the Virginia fuel cost recovery statute passed in 2004, our fuel factor provisions were frozen until July 1, 2007. Fuel prices increased considerably during that period, which resulted in our fuel expenses being significantly in excess of our fuel cost recovery. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were re-instituted beginning July 1, 2007. While the 2007 amendments did not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor was adjusted, this mechanism ensures dollar for dollar recovery for prudently incurred fuel costs.

In April 2007, we filed a Virginia fuel factor application with the Virginia Commission. The application showed a need for an annual increase in fuel expense recovery for the period July 1, 2007 through June 30, 2008 of approximately $662 million; however, the requested increase was limited to $219 million under the 2007 amendments to the fuel cost recovery statute, which limited the increase to an amount that resulted in the residential customer class not receiving an increase of more than 4% of total rates in effect as of June 30, 2007. The Virginia Commission approved a fuel factor increase for Virginia jurisdictional customers of approximately $219 million, effective July 1, 2007, with the balance of approximately $443 million deferred for subsequent recovery subject to Virginia Commission approval, without interest, during the period commencing July 1, 2008 and ending June 30, 2011.

In May 2008, we filed an application to revise our fuel factor with the Virginia Commission that would have resulted in an annual increase from 2.232 cents per kWh to 4.245 cents per kWh, effective July 1, 2008. This revised factor included $231 million of prior year under-recovered fuel expense out of a total estimated prior year under-recovered balance of $697 million with the remaining deferred fuel balance expected to be recovered over the next two fuel rate years beginning July 1, 2009. As part of the application, we proposed adoption of a rule that would limit the fuel factor to 3.893 cents per kWh for the current fuel period of July 1, 2008 through June 30, 2009. In order to achieve this lower fuel factor increase, the proposal would have delayed

recovery of the prior year under-recovered fuel balance of $697 million to be collected over a three-year period beginning July 1, 2009.

The Virginia Commission approved a Stipulation and Recommendation proposed by us and other parties, which provided for the following, effective July 1, 2008:

i) an increase of our fuel tariff to 3.893 cents per kWh for the collection of the current period and partial recovery of the prior year under-recovered fuel balance;
ii) the recovery of $231 million of the approximately $697 million prior year under-recovered fuel balance, with the balance to be recovered in subsequent fuel periods as provided by Virginia law;
iii) the fuel tariff of 3.893 cents per kWh is estimated to result in an under-recovery of $231 million of projected fuel expenses during the current period; and
iv) we will not propose to recover a return or interest or any other form of carrying costs on the balance of uncollected fuel expenses described in subsection (ii) above, including the estimated $231 million under-recovery of current period expenses described in subsection (iii), provided that the total amount on which we will not propose to recover interest or any other form of carrying costs is limited to $697 million.

The resulting increase in a 1,000 kWh Virginia jurisdictional residential customer s monthly bill is approximately 18% for the 2008 through 2009 fuel period.

North Carolina Regulation

In 2004, the North Carolina Commission commenced a review of our North Carolina base rates and subsequently ordered us to file a general rate case to show cause why our North Carolina jurisdictional base rates should not be reduced. The rate case was filed in September 2004, and in March 2005 the North Carolina Commission approved a settlement that included a prospective $12 million annual reduction in current base rates and a five-year base rate moratorium, effective as of April 2005. Fuel rates are still subject to annual fuel rate adjustments, with deferred fuel accounting for over- and under-recoveries of fuel costs.

NOTE 21. CREDIT RISK

We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our December 31, 2008 provision for credit losses, that it is unlikely a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

We sell electricity and provide distribution and transmission services to customers in Virginia and northeastern North Carolina. Management believes that this geographic concentration risk is mitigated by the diversity of our customer base, which includes residential, commercial and industrial customers, as well as rural electric cooperatives and municipalities. Credit risk associated with trade accounts receivable from energy consumers is limited due to the large number of customers.

Our exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Our gross credit

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exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At December 31, 2008, our gross credit exposure totaled $74 million. After the application of collateral, our credit exposure is reduced to $58 million. Of this amount, investment grade counterparties, including those internally rated, represented 79%, and no single counterparty exceeded 24%.

NOTE 22. RELATED-PARTY TRANSACTIONS

We engage in related-party transactions primarily with affiliates. Our receivable and payable balances with affiliates are settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. We are included in Dominion s consolidated federal income tax return and participate in certain Dominion benefit plans. A discussion of significant related party transactions follows.

Transactions with Affiliates

We transact with affiliates for certain quantities of natural gas and other commodities in the ordinary course of business. We also enter into certain commodity derivative contracts with affiliates. We use these contracts, which are principally comprised of commodity swaps and options, to manage commodity price risks associated with purchases of natural gas. We designate the majority of these contracts as cash flow hedges for accounting purposes.

DRS provides accounting, legal, finance and certain administrative and technical services to us. In addition, we provide certain services to affiliates, including charges for facilities and equipment usage.

Presented below are significant transactions with DRS and other affiliates:

Year Ended December 31, (millions)	**2008**	2007	2006
Commodity purchases from affiliates	**$ 527**	$ 373	$ 234
Services provided by affiliates	**399**	345	311
Services provided to affiliates	**29**	25	26

In September 2008, we purchased a gas-fired turbine from an affiliate for $36 million as part of an expansion project at our Ladysmith (Unit 5) to supply electricity during periods of peak demand.

In December 2008, we merged with DNNA as part of our continued development efforts associated with the possible construction of a third nuclear unit at our North Anna facility. This merger has been approved by the Virginia and North Carolina Commissions and became effective December 1, 2008. As a result of the merger, we recorded assets and liabilities of $48 million, primarily reflecting the acquisition of an ESP and an in-process COL, and a payable to an affiliate that is expected to be settled in early 2009.

We have borrowed funds from Dominion under short-term borrowing arrangements. At December 31, 2008 and 2007, our outstanding borrowings, net of repayments, under the Dominion money pool for our nonregulated subsidiaries totaled $198 million and $114 million, respectively. Our short-term demand note

borrowings from Dominion were $219 million at December 31, 2008. There were no short-term demand note borrowings at December 31, 2007. We incurred interest charges related to our borrowings from Dominion of $10 million, $27 million and $10 million in 2008, 2007 and 2006, respectively.

In December 2008, as approved by the Virginia Commission, we issued 11,786 shares of our common stock to Dominion reflecting the conversion of $350 million of short-term demand note borrowings from Dominion to equity.

Lehman Brothers Inc. (LBI), a Lehman subsidiary, formerly acted as a remarketing agent for $153 million of our variable rate tax-exempt pollution control bonds. Due to several unsuccessful remarketing auctions of our variable rate tax-exempt pollution control bonds following the Lehman bankruptcy, Dominion repurchased $14 million of these bonds in September 2008, which were successfully remarketed by Barclays Capital, Inc. as successor remarketing agent in November 2008. Of the $153 million in variable rate bonds, $78 million matured or were redeemed in 2008. These variable rate tax-exempt financings are supported by a stand-alone $182 million five-year credit facility that terminates in February 2011.

NOTE 23. OPERATING SEGMENTS

We are organized primarily on the basis of the products and services we sell. The majority of our revenue is provided through tariff rates. Generally, such revenue is allocated for management reporting based on an unbundled rate methodology among our DVP and Generation segments. We manage our daily operations through the following segments:

DVP includes our electric transmission, distribution and customer service operations.

Generation includes our generation and energy supply operations.

Corporate and Other primarily includes specific items attributable to our operating segments. The contribution to net income by our primary operating segments is determined based on a measure of profit that management believes represents the segments core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by executive management, either in assessing the segments performance or in allocating resources among the segments, and are instead reported in the Corporate and Other segment.

In 2008, the Corporate and Other segment included $23 million of net after-tax expenses attributable to our Generation segment. The net expenses in 2008 primarily related to impairment charges of $18 million ($11 million after tax) related to non-refundable deposits for certain generation-related vendor contracts and $8 million ($5 million after tax) reflecting other-than-temporary declines in the fair value of securities held as investments in our nuclear decommissioning trusts.

In 2007, the Corporate and Other segment included $166 million of net after-tax expenses attributable to our Generation segment. The net expenses in 2007 largely resulted from a $259 million ($158 million after tax) extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.

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In 2006, the Corporate and Other segment included $12 million of net after-tax expenses attributable to our Generation segment. The net expenses in 2006 primarily related to a $13 million ($8 million after tax) impairment charge in the fourth quarter resulting from a change in our method of assessing other-than-temporary declines in the fair value of securities held as investments in our nuclear decommissioning trusts.

The following table presents segment information pertaining to our operations:

Year Ended December 31, (millions)	DVP	Generation	Corporate and Other	Adjustments & Eliminations	Consolidated Total
2008					
Operating revenue	**$ 1,439**	**$ 5,478**	**$ 17**	**$**	**$ 6,934**
Depreciation and amortization	**310**	**298**			**608**
Interest income	**15**	**9**		**(3)**	**21**
Interest and related charges	**144**	**167**	**1**	**(3)**	**309**
Income taxes	**182**	**331**	**(13)**		**500**
Net income (loss)	**307**	**583**	**(26)**		**864**
Capital expenditures	**792**	**1,245**			**2,037**
Total assets	**8,339**	**11,858**		**(1,395)**	**18,802**
2007					
Operating revenue	$ 1,467	$ 4,709	$ 5	$	$ 6,181
Depreciation and amortization	299	254	15		568
Interest income	6	9	8	(7)	16
Interest and related charges	133	174	3	(6)	304
Income taxes	212	166	(7)		371
Extraordinary item, net of tax			(158)		(158)
Net income (loss)	342	276	(170)		448
Capital expenditures	559	736			1,295
Total assets	7,705	10,525		(1,167)	17,063
2006					
Operating revenue	$ 1,396	$ 4,202	$ 5	$	$ 5,603
Depreciation and amortization	293	225	18		536
Interest income	4	32	8	(6)	38
Interest and related charges	129	173		(6)	296
Income taxes	212	80	(8)		284
Net income (loss)	339	151	(12)		478
Capital expenditures	524	523			1,047

NOTE 24. QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of our quarterly results of operations for the years ended December 31, 2008 and 2007 follows. Amounts reflect all adjustments 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.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year

(millions)					
2008					
Operating revenue	**$ 1,524**	**$ 1,546**	**$ 2,177**	**$ 1,687**	**$ 6,934**
Income from operations	**418**	**390**	**561**	**252**	**1,621**
Net income	**222**	**200**	**303**	**139**	**864**
Balance available for common stock	**218**	**196**	**299**	**134**	**847**
2007					
Operating revenue	$ 1,443	$ 1,424	$ 1,833	$ 1,481	$ 6,181
Income from operations	181	191	582	272	1,226
Extraordinary item, net of tax		(158)			(158)
Net income (loss)	89	(79)	322	116	448
Balance available for common stock	85	(83)	318	112	432

Our 2007 results include the impact of the following significant items:

Second quarter results include a $158 million after-tax extraordinary charge due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.

Third and fourth quarter results reflect the reapplication of deferral accounting for Virginia jurisdiction fuel costs beginning July 1, 2007.

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

None.

Item 9A(T). Controls and Procedures

Senior management, including our CEO and CFO, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, our CEO and CFO have concluded that our disclosure controls and procedures are effective. There were no changes in our internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Virginia Electric and Power Company (Virginia Power) understands and accepts responsibility for our financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). We continuously strive to identify opportunities to enhance the effectiveness and efficiency of internal control, just as we do throughout all aspects of our business.

We maintain a system of internal control designed to provide reasonable assurance, at a reasonable cost, that our assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. 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.

The Board of Directors also serves as our Audit Committee and meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss our auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require our 2008 Annual Report to contain a management s report regarding the effectiveness of internal control. As a basis for our report, we tested and evaluated the design and operating effectiveness of internal controls. Based on our assessment as of December 31, 2008, we make the following assertion:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Virginia Power.

There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

We evaluated our internal control over financial reporting as of December 31, 2008. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework* issued by the Committee

of Sponsoring Organizations of the Treadway Commission. Based on this assessment, we believe that Virginia Power maintained effective internal control over financial reporting as of December 31, 2008.

This annual report does not include an attestation report of the company s registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by the company s independent registered public accounting firm pursuant to temporary rules of the SEC that permit the company to provide only management s report in this annual report.

Since management s assessment is required without an attestation report by the company s independent registered public accounting firm regarding internal control over financial reporting, management s report will be considered to be furnished rather than filed and therefore not subject to liability under Section 18 of the Exchange Act.

February 24, 2009

Item 9B. Other Information

Explanatory Note: The following information relates to pending changes to certain of our executive officer positions and is provided here in lieu of filing a Form 8-K that would otherwise have been filed under Item 5.02 for events occurring on February 24, 2009.

On February 25, 2009, it was announced that Thomas N. Chewning, Executive Vice President and Chief Financial Officer, will retire effective June 1, 2009.

It was also announced that Mark F. McGettrick, 51, has been chosen to succeed Mr. Chewning effective June 1, 2009 as Executive Vice President and Chief Financial Officer. Mr. McGettrick has been our President and Chief Operating Officer Generation since February 2006 and has also served as Executive Vice President of Dominion since April 2006. Mr. McGettrick was our President and Chief Executive Officer Generation from January 2003 to January 2006 and served in other executive and management positions with Dominion and its subsidiaries prior to that.

The following executive changes were also announced on February 25, 2009:

Paul D. Koonce, 49, was chosen to be President and Chief Operating Officer Dominion Virginia Power, effective June 1, 2009. He will also become the Chief Executive Officer of Dominion s Dominion Virginia Power business segment on June 1. Mr. Koonce has been an Executive Vice President of Dominion since April 2006. He served as our President and Chief Operating Officer Energy from February 2006 to September 2007 and our Chief Executive Officer Energy from January 2004 to January 2006. Mr. Koonce served in other executive and management positions with us prior to January 2004.

David A. Christian, 54, was chosen to be President and Chief Operating Officer Generation, effective June 1, 2009. Mr. Christian is currently our President and Chief Nuclear Officer. He will also become Chief Executive Officer of Dominion s Dominion Generation business segment on June 1.

David A. Heacock, 51, was chosen to be President and Chief Nuclear Officer, effective June 1, 2009. Mr. Heacock is currently our President and Chief Operating Officer Dominion Virginia Power.

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

Information concerning directors of Virginia Power, 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 Director
Thomas F. Farrell, II (54)	Chairman of the Board of Directors and CEO of Virginia Power from February 2006 to date; Chairman of the Board of Directors of Dominion from April 2007 to date; President and CEO of Dominion from January 2006 to date; Chairman of the Board of Directors, President and CEO of Consolidated Natural Gas Company (CNG) from January 2006 to June 2007; Director of Dominion from March 2005 to April 2007; President and Chief Operating Officer (COO) of Dominion and CNG from January 2004 to December 2005. Mr. Farrell is a director of Altria Group, Inc.	1999
Thomas N. Chewning (63)	Executive Vice President and CFO of Virginia Power from February 2006 to date; Executive Vice President and CFO of Dominion from May 1999 to date; Executive Vice President and CFO of CNG from January 2000 to June 2007.	1999
Steven A. Rogers (47)	President and Chief Administrative Officer (CAO) of DRS and Senior Vice President and CAO of Dominion from October 2007 to date; Senior Vice President and Chief Accounting Officer of Dominion and Virginia Power from January 2007 to September 2007 and CNG from January 2007 to June 2007; Senior Vice President and Controller of Dominion and CNG from April 2006 to December 2006; Senior Vice President (Principal Accounting Officer) (PAO) of Virginia Power from April 2006 to December 2006; Vice President and Controller of Dominion and CNG and Vice President and PAO of Virginia Power from June 2000 to April 2006.	2007

Audit Committee Financial Experts

We are a wholly-owned subsidiary of Dominion. As permitted by SEC rules, our Board of Directors serves as our Company s Audit Committee and is comprised entirely of executive officers of the Company or Dominion. Our Board of Directors has determined that Thomas F. Farrell, II, Thomas N. Chewning and Steven A. Rogers are audit committee financial experts as defined by the SEC. As executive officers of the Company and/or Dominion, Thomas F. Farrell, II, Thomas N. Chewning and Steven A. Rogers are not deemed independent.

Information concerning the executive officers of Virginia Power, each of whom is elected annually is as follows:

Name and Age	Business Experience Past Five Years(1)
Thomas F. Farrell, II (54)	Chairman of the Board of Directors and CEO of Virginia Power from February 2006 to date; Chairman of the Board of Directors of Dominion from April 2007 to date; President and CEO of Dominion from January 2006 to date; Chairman of the Board of Directors, President and CEO of CNG from January 2006 to June 2007; Director of Dominion from March 2005 to April 2007; President and COO of Dominion and CNG from January 2004 to December 2005.
Thomas N. Chewning (63)	Executive Vice President and CFO of Virginia Power from February 2006 to date; Executive Vice President and CFO of Dominion from May 1999 to date; Executive Vice President and CFO of CNG from January 2000 to June 2007.

David A. Heacock (51)	President and COO DVP of Virginia Power from June 2008 to date; Senior Vice President DVP of Virginia Power from October 2007 to May 2008; Senior Vice President Fossil & Hydro of Virginia Power from April 2005 to September 2007; Vice President Fossil & Hydro System Operations of Virginia Power from December 2003 to April 2005.
Mark F. McGettrick (51)	President and COO Generation of Virginia Power from February 2006 to date; Executive Vice President of Dominion from April 2006 to date; President and CEO Generation of Virginia Power from January 2003 to January 2006.
David A. Christian (54)	President and Chief Nuclear Officer (CNO) of Virginia Power from October 2007 to date; Senior Vice President Nuclear Operations and CNO of Virginia Power from April 2000 to September 2007.
Thomas P. Wohlfarth (48)	Senior Vice President and Chief Accounting Officer of Virginia Power, Dominion and DRS from October 2007 to date; Vice President Budgeting, Forecasting & Investor Relations of DRS from February 2006 to September 2007; Vice President Financial Management of Virginia Power from January 2004 to January 2006.

(1) Any service listed for Dominion, DRS and CNG reflects services at a parent, subsidiary or affiliate. There is no family relationship between any of the persons named in response to Item 10.

Code of Ethics

We have adopted a Code of Ethics that applies to our principal executive, financial and accounting officers, as well as our employees. This Code of Ethics is available on the corporate governance section of Dominion s website (*www.dom.com*). You may also request a copy of the Code of Ethics, free of charge, by writing or telephoning the Company at: Corporate Secretary, 120 Tredegar Street, Richmond, Virginia 23219, Telephone (804) 819-2000. Any waivers or changes to our Code of Ethics will be posted on the Dominion website.

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Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

We are a wholly-owned subsidiary of Dominion. Our Board is comprised of Messrs. Farrell, Chewning and Rogers. Messrs. Farrell and Chewning are not independent because they are executive officers of the Company. Mr. Rogers is not deemed independent because of his employment with Dominion. Because our Board believes that it is more appropriate for our compensation program to be managed under the direction of individuals who are independent, we do not have a compensation committee. Instead, our Board depends on the advice and recommendations of Dominion s Compensation, Governance and Nominating Committee (CGN Committee), which is comprised of independent directors and which retained the consulting firm of Pearl Meyer & Partners (PM&P) to advise them on compensation matters. Our Board approves all compensation paid to executive officers based on the CGN Committee s recommendations. None of our directors, who are officers of the Company or Dominion, receive any compensation for the services they provide as directors.

Because the CGN Committee effectively administers one compensation program for all of Dominion, the following discussion and analysis is based on Dominion s overall compensation program.

INTRODUCTION

This Compensation Discussion and Analysis is designed to provide you with a transparent, understandable, and detailed explanation of the objectives and principles that underlie our executive compensation program; its elements; and the way successful performance is measured, evaluated, and rewarded.

During one of the most challenging economic periods in recent memory, Dominion delivered strong operating and financial performance in 2008, exceeding its earnings guidance for the year. Dominion also increased its dividend rate by 11% and maintained more than adequate liquidity. While total shareholder returns across all major sectors, including energy, were negative in 2008, Dominion performed very well against its sector, the S&P 500, and the S&P Utility Index. In 2008, Dominion ranked fourth versus its peer group of 14 companies (excluding Dominion) in cumulative total shareholder return for the one-year period ending December 31, 2008, and sixth out of 14 peers for the two-year period ending December 31, 2008. Dominion s successful execution of the divestiture of a significant portion of its exploration and production (E&P) business, and resulting realignment of Dominion toward utility-based infrastructure businesses, supported these excellent results.

Dominion s executive compensation program plays an important role in its success by placing a significant amount of compensation at risk based on the achievement of performance objectives.

Although the executive compensation program and processes generally apply to all officers, this discussion and analysis focuses primarily on compensation for the five named executive officers (NEOs) of Virginia Power. During 2008, our NEOs were:

Thomas F. Farrell, II, Chairman and CEO
Thomas N. Chewning, Executive Vice President and CFO
Mark F. McGettrick, President and Chief Operating Officer (COO) Generation
David A. Heacock, President and COO DVP
David A. Christian, President and Chief Nuclear Officer Generation

This Compensation Discussion and Analysis is divided into three parts:

1. **Objectives of Dominion s Executive Compensation Program and the Compensation Decision-Making Process**. The major objectives of the program are described as well as the processes and tools the CGN Committee utilizes to assist it with fulfilling its responsibilities related to NEO compensation and making decisions that support its objectives.

2. **Elements of Dominion s Compensation Program**. The four compensation elements used to achieve Dominion s objectives are described. This part also includes data regarding the decisions made and compensation earned by the NEOs in 2008, including the performance targets for the 2007 and 2008 incentive programs.
3. **Other Relevant Compensation Practices**. Other matters considered in designing our compensation program are discussed.

OBJECTIVES OF DOMINION S EXECUTIVE COMPENSATION PROGRAM AND THE COMPENSATION DECISION-MAKING PROCESS

Objectives

The major objectives of Dominion s compensation program are to:

- Attract, motivate, and retain an experienced and superior management team;
- Motivate and reward the creation of long-term shareholder value;
- Reinforce core values of safety, ethics, excellence, and One Dominion, our term for teamwork; and
- Support our business strategy and business plans with a performance-based program that sets expectations in line with the strategy and plans, and rewards the achievement of these expectations.

Dominion s 2008 performance indicates that the design of its compensation program is meeting these objectives. Our NEOs have service with Dominion ranging from 14 to 33 years. Dominion has attracted, motivated, and maintained a superior leadership team with skills, industry knowledge, and institutional experience that strengthen their ability to act as sound stewards of the interest of Dominion shareholders as well as the interests of our ratepayers.

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Process for Setting Compensation

The CGN Committee is responsible for reviewing and approving NEO compensation and the executive compensation program and policies overall. Each year, the CGN Committee conducts a comprehensive assessment and analysis of the executive compensation program, including each NEO s compensation, with input from management and PM&P. As part of its assessment, the CGN Committee reviews the performance of Dominion s CEO and other executive officers, meets at least annually with Dominion s CEO to discuss succession planning for his position and the positions of his senior officers, reviews the share ownership guidelines and executive officer compliance with the guidelines, and establishes compensation programs designed to achieve Dominion s objectives.

The Role of the Independent Compensation Consultant

The CGN Committee has retained PM&P as its independent compensation consultant. PM&P does not provide any other services to Dominion other than its consulting services to the CGN Committee on executive and director compensation matters. The PM&P consultant participates in CGN Committee meetings as requested by the chairman of the committee, either in person or by teleconference. The consultant also communicates directly with the chairman of the committee outside of meetings. The nature and scope of PM&P s services for Dominion s executive compensation program for 2008 were as follows:

- To perform a detailed review of the base salary and annual bonus potential (total cash), and the value of targeted long-term incentives and total direct compensation (total cash plus targeted long-term incentive compensation) for the NEOs, and to provide a full report to the CGN Committee on its findings;
- To participate in the selection of Dominion s peer companies, providing independent advice to the CGN Committee on the process used to select the peer group and the appropriateness of such peer group;
- To participate in CGN Committee executive sessions without management present to discuss CEO compensation and any other relevant matters, including the appropriate relationship between pay and performance and emerging trends, and to answer technical questions and provide review and comment on management proposals; and
- To generally review and offer advice to the CGN Committee regarding other aspects of Dominion s executive compensation program, including special projects, plan design, best practices, and other matters as requested by or on behalf of the CGN Committee.

Management s Role in the Process

The CGN Committee relies on Dominion s internal compensation specialists in its Governance and Executive Compensation Departments for additional counsel, data, and analysis for the executive compensation program, including an ongoing assessment of the effectiveness of the program, peer practices, and executive compensation trends and best practices. Working with the CFO s team, the Human Resources group, the CEO, and others, the internal compensation specialists assist in the design of Dominion s incentive compensation plans, including performance target recommendations consistent with the strategic goals of

Dominion and the Company, and in establishing the peer group. This group also provides information and support to the independent compensation consultant at the direction of the CGN Committee.

On an annual basis, the CEO is responsible for reviewing with the CGN Committee his succession plans for his own position and for his senior officers. He is also responsible for reviewing the performance of his senior officers, including the other NEOs, with the Committee at least annually. He makes recommendations on the compensation and benefits for the NEOs other than himself to the CGN Committee and provides other information and counsel as appropriate or as requested by the Committee, but all decisions are ultimately made by the CGN Committee.

The Peer Group and Peer Group Comparisons

Each year, the CGN Committee approves a peer group of companies. The CGN Committee and Dominion use peer company data to (i) compare Dominion s stock and financial performance against its peers using a number of different metrics and time periods to evaluate how Dominion is performing versus its peers; (ii) analyze compensation practices within Dominion s industry; (iii) help determine peer company practices and the peer median and 75th percentile benchmarks for base pay, annual incentive pay, long-term incentive pay, and total direct compensation generally and for specific positions; and (iv) compare Employment Continuity Agreements and other benefits.

In selecting the peer group, Dominion uses a methodology recommended by its independent compensation consultant to identify companies in its industry that compete for customers, executive talent, and investment capital. Dominion screens this group based on size, and companies that are much smaller or larger than Dominion s size in revenues, assets, and market capitalization are eliminated. Dominion also considers the geographic locations and regulatory environment in which potential peer companies operate.

Dominion s peer group is generally consistent from year to year, with merger and acquisition activity being the primary reason for any changes. The 2008 peer group was a diversified group consisting of the following 14 energy companies:

Ameren Corporation	FirstEnergy Corp.
American Electric Power Company, Inc.	FPL Group, Inc.
Constellation Energy Group, Inc.	NiSource, Inc.
DTE Energy Company	PPL Corporation
Duke Energy Corporation	Progress Energy, Inc.
Entergy Corporation	Public Service Enterprise Group Inc.
Exelon Corporation	Southern Company

Survey Data

Survey compensation data is used as a reference point for market comparison of the elements of compensation for all officers. In conducting its review of NEO compensation, PM&P uses a combination of survey and peer group information to establish the 50th percentile and the 75th percentile for base salary, total cash compensation, long-term incentive awards, and total direct compensation for the NEO positions. For 2008 compensation decisions, the survey information used for NEO positions consisted of an average of three to four broad-based or industry-specific surveys of compensation paid to officers holding similar positions at companies with corporate revenues consistent with

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Dominion s revenues. The CGN Committee does not consider the individual components of each survey in making its compensation decisions. The component companies of the surveys used in 2008 are listed in Exhibit 99.

The relative weighting of survey compensation data and peer group compensation data depends on the availability of appropriate peer group matches for the specific NEO. Historically and for 2008, PM&P has considered survey data and specific peer company data, if relevant position matches are available, in establishing the blended market benchmarks for the NEO positions. As part of its annual evaluation, PM&P determines the appropriate weighting of market data resources for each NEO. For 2008, survey data are weighted at least 50%, with the weighting up to 100% where the number of appropriate peer group matches is not sufficient to provide meaningful comparisons. The CGN Committee typically considers the blended market data as context for its compensation determinations, rather than each of the specific market data resources.

Although Dominion compares its officer compensation levels to the blended market data for each position, Dominion administers its program to meet the needs and requirements of Dominion rather than only matching pre-set market levels for any component of compensation or for total direct compensation. As discussed in *Factors in Setting Compensation*, comparative data is just one of several considerations used in setting compensation at Dominion. Generally, the program is designed to pay base salary and total cash compensation at or slightly above the 50^{th} percentile for the officers as a group. Total direct compensation is targeted between the 50^{th} and 75^{th} percentiles, but actual achievement of the incentive-based compensation goals will determine what is actually earned.

Due to the broad participation in the surveys, Dominion does not benchmark its financial performance against any of the survey population. Dominion considers its peer companies to be more relevant and so Dominion does benchmark its financial and stock performance against its peer companies as part of its annual compensation setting process, as discussed above in *The Peer Group and Peer Group Comparisons*.

Other Tools

The CGN Committee uses a number of tools in its annual review of the compensation of the CEO and other NEOs, such as charts illustrating the total range of payouts for each performance-based compensation element under a number of different scenarios; spreadsheets showing the cumulative dollar impact on total direct compensation that could result from implementing proposals on any single element of compensation; graphs showing the relationship between the CEO s pay and that of the second highest paid officer and NEOs as a group; and other information the CGN Committee may request in its discretion. On an annual basis, management s internal compensation specialists provide the CGN Committee with detailed comparisons of the design and features of Dominion s long-term incentive and other executive benefit programs with available information regarding similar programs at the peer companies. These tools are used as part of the overall process to ensure the program results in appropriate pay relationships versus the market and internally among the NEOs, and that an appropriate balance of at risk, performance-based compensation is maintained to support the program s core objectives.

Risk Assessment

In early 2009, the CGN Committee, with the assistance of PM&P and Dominion s chief risk officer, reviewed the overall structure of Dominion s executive compensation program, as well as specific components of the program, to confirm the program does not encourage excessive risk-taking by officers, and is aligned with Dominion s risk management efforts and overall strategies. The CGN Committee believes that Dominion s well-balanced program of short and long-term incentives with a mix of performance goals, together with its strong share ownership requirements and retention expectations appropriately position the overall program from a risk perspective. In addition, as noted in *Recovery of Incentive Compensation*, the CGN Committee has expanded its authority for the recovery of any performance-based compensation in the event of fraudulent conduct or intentional misconduct.

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ELEMENTS OF DOMINION S COMPENSATION PROGRAM

Dominion s executive compensation program consists of four basic elements:

Pay Element	Primary Objectives	Key Features and Behavioral Focus
Base Salary	Provide competitive level of fixed cash compensation for performing day-to-day responsibilities Attract and retain talent	Targeted at market median with adjustments based on internal equity and other company considerations Rewards individual performance and level of experience
Annual Incentive Plan	Provide at-risk variable cash compensation for achievement of short-term financial and operational goals Aligns short-term compensation with our annual budget, earnings goals, business plans, and core values	Cash payments based on achievement of financial and individual goals Rewards achievement of annual financial and operational goals for Dominion and individual and business unit goals selected to support longer-term strategies
Long-Term Incentive Program	Provide at-risk variable compensation for achievement of long-term performance goals Creation of long-term shareholder value Retention tool	A combination of performance-based cash and restricted stock awards (typically, a 50/50 mix) Encourages and rewards officers for making decisions and investments that achieve desired returns on invested capital and that create long-term shareholder value as reflected in relative total shareholder return and book value
Employee and Executive Benefits	Provide competitive retirement and other benefit programs that attract and retain highly-qualified individuals Provide competitive terms to encourage executives to remain with us during any potential change in control to ensure an orderly transition of management	Dominion benefit programs, supplemented by executive retirement plans, limited perquisites, and change in control and other agreements Encourages officers to remain with us long-term and to act in the shareholders best interests, even during any potential change in control

Factors in Setting Compensation

The CGN Committee reviews Dominion s overall performance versus its peer companies, its strategies, and its short and long-term goals in setting compensation targets, approving payouts and designing future programs. In addition to considering Dominion s overall performance for the year, several individual factors that are not given any specific weighting in setting each element of compensation for each NEO are taken into consideration, including:

- An officer s experience and job performance;
- The scope of responsibility for a position, including any differences from peer company positions or market survey data;

- The relative importance of a particular position to Dominion s strategy and success, and comparability to other officer positions at Dominion;
- Retention and market competitive concerns; and
- The officer s role in any succession plan for other key positions.

CEO Compensation Relative to Other NEOs

Mr. Farrell participates in the same compensation programs and receives compensation based on the same philosophy and factors

as other NEOs. Application of the same philosophy and factors to Mr. Farrell s position results in overall CEO compensation that is significantly higher than the compensation of the other NEOs. His compensation is commensurate with his greater responsibilities and decision-making authority, broader scope of duties that encompasses the entirety of the Company (as compared to the other NEOs who are responsible for significant but distinct areas within the Company), and his overall responsibility for the corporate strategy. His compensation also reflects his role as our primary corporate representative to investors, regulators, analysts, politicians, industry, and the media.

Dominion considers CEO compensation trends versus the next highest paid officer and executive officers as a group over a multi-year period to monitor the ratio of Mr. Farrell s pay relative to the pay of other executive officers based on (i) salary only and (ii) total direct compensation. Dominion compares its ratios to that of its peers to confirm the ratios are consistent with practices at the peer companies. There is no particular ratio or goal, but instead the CGN Committee considers year-to-year trends and comparisons with Dominion s peers. The CGN Committee did not make any adjustments to the compensation of any NEOs based on this review in 2008.

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Allocation of Total Direct Compensation in 2008

Consistent with Dominion s objective to reward strong performance based on the achievement of short-term and long-term goals, a significant portion of total cash and total direct compensation is at risk. Approximately 86% of Mr. Farrell s targeted 2008 total direct compensation is performance-based tied to pre-approved performance metrics or tied to the performance of Dominion s stock, and approximately 50% of his targeted 2008 total cash compensation is at risk. For the other NEOs, 2008 targeted performance-based compensation ranges from 65% to 79%. This compares to an average of approximately 37% of targeted compensation at risk for most officers at the Dominion vice president level and an average of approximately 13% of total pay at risk for Dominion s non-officer employees.

The charts below illustrate the elements of total direct compensation opportunities in 2008 for Mr. Farrell and the other NEOs and the allocation of such compensation among base salary, targeted 2008 annual incentive plan award, and targeted 2008 long-term incentive compensation.

Base Salary

In setting the 2008 base salaries for the NEOs, the CGN Committee considered market data (as described above in The *Peer Group and Peer Group Comparisons* and *Survey Data*), peer practices generally, and individual performance and scope and complexity of their positions relative to other positions at Dominion.

Base salary compensates officers, along with the rest of the workforce, for committing significant time to working on Dominion s behalf. Annual salary reviews achieve two primary purposes: (i) an annual adjustment as appropriate to keep salaries in line and competitive with the market and to reflect changes in responsibility, including promotions; and (ii) a motivational tool to acknowledge and reward excellent individual performance, special skills, experience, the strategic impact of a position relative to other Dominion executives, and other relevant considerations.

While the base salary component of the program generally is targeted at or slightly above market median, the primary goal is to compensate officers at a level that best achieves Dominion s objectives and reflects the considerations discussed above. Dominion finds that proxy and survey results for particular positions can vary greatly from year to year, so it considers market trends for certain positions over a period of years rather than a one-year period in setting base salaries for such positions. Dominion believes that an overall goal of targeting base salary at or slightly above the market median is a conservative but appropriate target for base pay. In addition, the scope of Dominion s business operations is complex and unique in its industry. Successfully managing such a diverse and complex business requires a skilled and experienced management team. We believe we would not be able to successfully recruit and retain such a team if the base pay for officers was below market-median, or in the case of our nuclear officers, below levels closer to the 75th percentile.

The details of the 2008 base salary increases for the NEOs are noted below and are consistent with the philosophy described above.

Dominion is taking a different approach for 2009 due to uncertain market conditions and slowed economic growth. While individual and Dominion performance and the most recent market data would support merit increases of 4% or more for the NEOs, base salary increases for the NEOs other than Mr. Farrell are capped at 2.5%. At Mr. Farrell s request, the CGN Committee maintained his 2008 base salary at the same level for 2009.

Mr. Farrell. Mr. Farrell received a 9% increase in his base salary in 2008. When Mr. Farrell was promoted to the position of President and CEO of Dominion in 2006, the CGN Committee determined it would raise his base salary to be in line with the market median for his position over the course of a few years. The process for establishing and considering the market median for NEOs is outlined above in *The Peer Group and Peer Group Comparisons* and *Survey Data*. His salary increase for 2008 brought his base salary in line with the market median for his position. In setting this increase, the CGN Committee also considered Mr. Farrell s exemplary performance and leadership during 2007, including his successful implementation of the Dominion Board-approved strategy to divest a significant portion of Dominion s Exploration & Production

(E&P) assets and realign Dominion s operating segments into the current organizational structure.

Mr. Chewning. In 2007, Mr. Chewning skillfully and successfully oversaw the financial ramifications related to the divestiture of a significant portion of Dominion s E&P assets, providing strategic guidance with respect to a new dividend policy and investor relations efforts following that divestiture, and the strategy for the use of proceeds from such divestiture, including the repurchase of Dominion common stock and reduction of debt. As expected for someone who has served in his position for over 10 years, Mr. Chewning s base salary was already consistent with the market median for his position. The CGN Committee approved a 4% base salary increase for him in 2008 to keep pace with the anticipated increase in compensation for his peers.

Mr. McGettrick. Mr. McGettrick is the CEO of our Generation operating segment, overseeing operational performance of the nuclear and fossil and hydro facilities. He has responsibility over a significant capital expenditure plan aimed at implementing strategic plans to meet the growing demand for energy in our service territories, along with significant efforts towards protecting the environment and improving the efficiency of our generation facilities. In recognition of his achievements, and to bring his base salary up to the market median for his position, Mr. McGettrick received a 12% base salary increase in 2008.

Mr. Heacock. In 2007, Mr. Heacock was promoted to President and COO of DVP, overseeing its electric delivery systems, and having responsibility for growth in its electric transmission investments. Mr. Heacock also serves on the Virginia Governor s Commission on Climate Change. In recognition of his achievements, and to bring his base salary up to the market median for his position, Mr. Heacock received a 10% base salary increase in 2008.

Mr. Christian. In 2007, Mr. Christian was promoted to President of Dominion Nuclear (which is part of the Generation operating segment), while retaining his position as Chief Nuclear Officer. Consistent with Dominion s strategy of compensating the nuclear group at levels closer to the market 75th percentile, and in recognition of his continuing outstanding performance and that of the nuclear group, the CGN Committee approved a 6% base salary increase for Mr. Christian in 2008, keeping him in line with the market 75th percentile.

The Annual Incentive Plan

Overview

The Annual Incentive Plan (AIP) plays an important role in meeting Dominion s overall objective of rewarding strong performance. The AIP is a cash-based program focused on short-term goal accomplishments. All non-union employees scheduled to work 1,000 hours or more in a calendar year and union employees covered under collective bargaining agreements that provide for participation in our annual incentive plan are eligible to participate in the AIP.

The AIP is designed to:

- Tie interests of Dominion shareholders and employees closely together;
- Focus our workforce on company, operating group, team and individual goals that ultimately influence operational and financial results;
- Reward corporate and operating group earnings performance;
- Reward operating and stewardship (including safety) and Six Sigma success;
- Emphasize teamwork by focusing on common goals; and
- Provide a competitive total compensation opportunity.

Target Awards

An NEO s compensation opportunity under the AIP is based on his target award. Target awards are determined as a percentage of a participant s annualized base salary as of the last day of the plan year (for example, 95% of base salary). The target award is the amount of cash that will be paid if a participant achieves a score of 100% for the goals established at the beginning of the year and the plan is funded at the threshold funding target set for the year. The AIP target awards established for the NEOs and other officers are generally designed so that the officer s total cash compen-

sation for the year will be at or slightly above the market median if the plan goals are achieved. If the AIP goals are exceeded, as they were in 2008, an officer s total cash compensation may be higher than market median, depending on the extent to which goals are exceeded. If the goals are not achieved, the officer s total cash compensation may be significantly lower than market median, depending on the extent to which goals are not achieved. For Mr. Christian and other nuclear officers, target compensation is more consistent with market 75th percentile overall in recognition of the significant size and outstanding performance of the nuclear unit, competition in that industry, and the unique skills and experience that the nuclear officers contribute to that program.

For the 2008 AIP, annual incentive targets were consistent with the CGN Committee s intent to have a significant portion of compensation at risk for NEOs. The 2008 AIP targets for the NEOs, as a percentage of base salary, were: Mr. Farrell 125%; Mr. Chewning 95%; Mr. McGettrick 95%; Mr. Heacock 70%; and Mr. Christian 70%. The AIP target for Mr. Farrell was increased by 5% to move his targeted total cash compensation closer to the market median. Mr. Heacock s AIP target was increased from 50% to 70% for 2008 due to his promotion to the position of President and COO of DVP. The AIP targets for the other NEOs did not increase in 2008 from their 2007 percentages.

FUNDING OF THE 2008 AIP

Funding of the 2008 AIP was based solely on consolidated operating earnings per share, with potential funding ranging from 0% to 200% of the target funding. Consolidated operating earnings per share are our reported earnings determined in accordance with GAAP, adjusted for certain items. Dominion believes that by placing a focus on pre-established consolidated operating earnings per share targets, we increase employee awareness of financial objectives and drive behavior and performance that will help achieve these objectives.

The 2008 AIP had a full funding target of $3.09 operating earnings per share for Dominion, the approximate mid-point of Dominion s 2008 earnings guidance announced in January 2008. Once the target is achieved, funding is based on a formula that provides equal sharing of consolidated operating earnings between plan participants and Dominion shareholders up to the maximum plan funding level of 200%.

Full funding means that the plan is 100% funded and participants can receive their full targeted AIP payout if they achieve a score of 100% for their particular goal package, as described below in *AIP Payouts*. At the maximum plan funding level of 200%, participants can earn up to two times their targeted AIP payout, subject to achievement of their individual goal packages.

Dominion reported $3.16 operating earnings per share for 2008, or $1.83 billion in consolidated operating earnings, which for 2008 is the same as the earnings reported in accordance with GAAP. This resulted in 157% funding for the 2008 AIP.

AIP PAYOUTS

For most officers, payout of funded bonuses for 2008 was subject to the accomplishment of business unit financial, operating and stewardship (including a required safety goal), and Six Sigma goals. The percentage allocated to each category of goals represents the percentage of the funded bonus subject to the performance of that goal.

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Officer goals are weighted according to their responsibilities. The overall score cannot exceed 100%. The table below summarizes the goal weighting for the NEOs. The consolidated financial goal represents the portion of the target bonus subject to the funding goal only.

	Consoli-dated Financial Goal	Business Unit Financial Goals	Operating/ Stewardship*	Six Sigma
Thomas F. Farrell, II	90%	N/A	5%	5%
Thomas N. Chewning	90%	N/A	5%	5%
Mark F. McGettrick	60%	30%	5%	5%
David A. Heacock	40%	30%	25%	5%
David A. Christian	40%	30%	25%	5%

* *5% of this goal weighting is for a safety goal. Messrs. Heacock and Christian had other, non-safety operating and stewardship goals, as described below.*

To preserve the tax deduction for payout amounts for Dominion officers whose compensation may be subject to deduction limits imposed by Internal Revenue Code Section 162(m), payout for those officers is based solely on the achievement of the consolidated operating earnings goal, with the CGN Committee having the ability to exercise negative discretion as deemed appropriate based on the achievement of discretionary business unit financial, operating and stewardship, and Six Sigma goals. Compensation paid to the NEOs other than Mr. Chewning and Mr. Heacock is subject to the Section 162(m) tax deduction limits.

Business unit financial goals provide a line-of-sight performance target to officers within a business unit and, on a combined basis, support the consolidated operating earnings target for Dominion.

The 2008 business unit financial goals and accomplishment levels for Mr. Heacock (DVP) and Messrs. McGettrick and Christian (Dominion Generation) were as follows:

Operating Segment	Threshold (Net Income) (million/$)	100% Payout (Net Income) (million/$)	2008 (Net Income) (million/$)	2008% Accomplishment
DVP	$ 326	$ 408	$ 380	95%
Dominion Generation	884	1,105	1,227	100%

Operating and stewardship goals provide line-of-sight performance targets that may not be financial and that can be customized for each individual or by segments of each business unit. Operating and stewardship goals promote the core values of safety, ethics, excellence, and teamwork, which in turn contribute to our financial success. In 2008, safety was a required operating and stewardship goal for all officers and employees, with a minimum weighting of 5%.

Messrs. Farrell, Chewning, McGettrick and Christian adopted a safety goal of minimizing OSHA recordable incident rates to a specified target number. Mr. Heacock adopted a safety goal of minimizing days away restricted duty and lost time (DART) incidents. All of the NEOs achieved their safety goals and Dominion overall had its fifth straight year of improved safety performance.

With the exception of Messrs. Heacock and Christian, the NEOs did not hold any operating and stewardship goals other than safety goals.

Mr. Heacock. In addition to his safety goal, which was weighted 5%, Mr. Heacock had operating and stewardship goals in four categories and each goal carried a 5% weighting: power outage durations, Mega-watt Hours lost to Generation Upstream (MWH), Implementation of Electric DSM Pilots, and Call Center Average Speed of Answer (ASA). His power outage duration goal was tied to the System Average Outage Duration Index (SAIDI) and this goal was achieved. Mr. Heacock s MWH goal was to keep MWH lost to generation upstream below a specified level; this goal was not fully achieved. Mr. Heacock oversaw the successful implementation of Conservation/Electric DSM pilots and achieved full credit for this goal. Mr. Heacock also received extra credit for exceeding his ASA goal of lowering the average speed of answering customer call center calls to less than 90 seconds. The Six Sigma goal extra credit of 2% as well as extra credit for exceeding the ASA goal were applied to offset the lost MWH goal shortfall, resulting in 100% goal achievement for Mr. Heacock s operating and stewardship goals.

Mr. Christian. In addition to his safety goal, which was weighted 6.25%, Mr. Christian had operating and stewardship goals in four other categories, weighted as indicated: Collective Radiation Exposure (5%), Capacity Factor (5%), Environmental Stewardship (3.75%) and Production Cost (5%). Mr. Christian s Collective Radiation Exposure (CRE) goal was to minimize the radiation exposure to all personnel in the nuclear business unit based on As Low As Reasonably Achievable (ALARA) standards and performance in this area was better than the targeted goal. Mr. Christian s Capacity Factor (CF) goal was to achieve or exceed a targeted CF percentage; CF, expressed as a percentage, is actual generation divided by projected generation. The CF goal was not fully achieved. Mr. Christian s Environmental Stewardship goal was to minimize the number of environmental performance points assessed at each of the nuclear stations to a specified target number. This goal was not achieved, with more points actually assessed than the target number. Mr. Christian s Production Cost goal was to cap these costs at targeted numbers. The Production Cost goal was not fully achieved. The Six Sigma goal extra credit of 2% was applied to partially offset Mr. Christian s CF and Production Cost goal shortfalls, resulting in 84% goal achievement for his operating and stewardship goals.

Dominion implemented the Six Sigma program in 2001 to use data and statistical analysis to measure and improve operational performance. Six Sigma goals are designed to increase productivity, reduce costs, and improve customer service. The Six Sigma goal for 2008 had a 5% weighting made up of two parts, with 2% tied to financial and improvement targets established for each business unit and a 3% weighting tied to a Dominion-wide savings goal of at least $85 million. Achievement of the business unit goals contributed to the overall $85 million financial target. If the positive financial impact for Dominion was $120 million or more, a 2% credit was granted that could be applied to offset any shortfall in operating and stewardship goals other than goals based on safety and regulatory compliance. Each business unit achieved its individual Six Sigma goals for 2008. The Six Sigma positive financial impact for Dominion exceeded $120 million, resulting in all employees earning the 2% extra credit, which was applied to offset any goal shortfalls other than goals based on safety and regulatory compliance.

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2008 AIP PAYOUTS

The formula for calculating an award is:

Amounts earned under the 2008 AIP by NEOs are set forth below and are also reflected in the *Summary Compensation Table* under the *Non-Equity Incentive Plan Compensation* column. The CGN Committee exercised negative discretion to lower Mr. Christian s payout score from 100% to 98% due to under-achievement of his operating and stewardship goals.

Name	Base Salary		Target Award		Funding %		Total Payout Score%		2008 AIP Payout
Thomas F. Farrell, II	$ 456,000	x	125%	x	157%	x	100%	=	$ 894,900
Thomas N. Chewning	299,420	x	95	x	157	x	100	=	446,585
Mark F. McGettrick	330,201	x	95	x	157	x	100	=	492,494
David A. Heacock	291,834	x	70	x	157	x	100	=	320,725
David A. Christian	264,775	x	70	x	157	x	98	=	285,167

Note: The executives included in this table may perform services for more than one subsidiary of Dominion. Compensation for the individuals listed in the table reflect only the approximate portion related to their service for Virginia Power in the year presented.

The Long-Term Incentive Program

OVERVIEW

The long-term incentive program focuses on longer-term goals and retention. In recent years, 50% of the long-term incentives have been full value equity awards in the form of restricted stock with time-based vesting and the other 50% have been performance-based awards. Dominion believes restricted stock serves as a strong retention tool and also creates a focus on stock price to further align the interests of officers with the interests of its shareholders. For those officers who have made substantial progress towards their share ownership guidelines, 50% of their long-term award is in the form of a cash performance grant. Because officers are expected to retain ownership of shares from vesting restricted stock awards, as explained in *Share Ownership Guidelines*, the long-term cash grant balances the program and allows a portion of the long-term award to be accessible to our NEOs during the course of their employment.

The long-term incentive target awards established for the NEOs and other officers are generally designed so that the officer s targeted total direct compensation is between the market median and the 75th percentile, with potential total direct compensation ranging from below the market median to slightly above the market 75th percentile depending on the extent to which the goals are achieved. Dominion targets the 75th percentile for certain officers, including Mr. Chewning and Mr. Christian, to address and recognize specific skills, competitive market pressures, retention needs and performance. On average, the long-term incentive values for our NEOS are between the market median and the 75th percentile positioning.

The fact that an officer may have received long-term incentive awards over the course of his or her career is not a significant factor in determining the officer s entitlement to appropriate long-term incentive awards in the current year, although prior awards are considered. If a newer officer does not have prior grants outstanding due to his or her short tenure, the compensation paid to such officer is not increased due to a lack of outstanding grants from prior years.

Since 2006, long-term grants have been made at the beginning of the second quarter of the year. In 2009, the CGN Committee transitioned to a February grant date that is closer to the beginning of the performance period, follows Dominion s year-end earnings call, and is more consistent with the practices of Dominion s peers.

2008 Restricted Stock Grants

All officers received a restricted stock grant on April 1, 2008 based on a stated dollar value. The number of shares awarded was determined by dividing the stated dollar value by the closing price of Dominion s common stock on March 31, 2008. The grants have a three-year vesting term, with cliff vesting at the end of the restricted period on April 1, 2011. The fair value of each NEO s 2008 restricted stock grant is disclosed in the *Grants of Plan-Based Awards* table.

2008 Cash Performance Grants

Most officers, including the NEOs, received cash performance grants on April 1, 2008. Officers who have not achieved 50% of their targeted share ownership guideline received stock-based performance grants. The performance period commenced on January 1, 2008 and will end on December 31, 2009. Like the 2007 performance grants, the 2008 grants are denominated as a target award, with potential payouts ranging from 0-200% of the target based on Dominion s total shareholder return (TSR) relative to the peer group of companies selected by the CGN Committee and Dominion s return on invested capital (ROIC). In addition, 2008 performance grants include a third metric: increase in book value per share.

Relative TSR (50% weighting) TSR is the difference between the value of a share of common stock at the beginning and end of the performance period, plus dividends paid as if reinvested in stock. The TSR metric was selected to focus officers on considering long-term shareholder value when developing and implementing strategic plans and in turn, reward management based on the achievement of TSR levels as measured relative to peer companies. The peer group for

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the 2008 performance grant is the same group of companies described above in *Peer Group and Peer Group Comparisons.* The relative TSR targets and corresponding payout scores are as follows:

Relative TSR Performance	Percentage Payout of TSR Percentage*
Top Quartile 75 % to 100%	150% 200%
2nd Quartile 50% to 74.9%	100% 149.9%
3rd Quartile 25% to 49.9%	50% 99.9%
4th Quartile below 25%	0%

* *TSR weighting is interpolated between the top and bottom of the percentages within a quartile. A minimum payment of 25% of the TSR percentage will be made if the TSR performance is at least 10% on a compounded annual basis for the performance period, regardless of relative performance.*

ROIC (40% weighting). ROIC reflects Dominion s total return divided by average invested capital for the performance period. For this purpose, total return is Dominion s consolidated operating earnings plus its after-tax interest and related charges, plus preferred dividends. The ROIC metric was selected to reward the achievement of expected levels of return on Dominion s investments. Dominion believes an ROIC measure encourages management to choose the right investments, and with those investments, to achieve the highest returns possible through prudent decisions, management and control of costs. The ROIC performance targets and corresponding payout scores are as follows:

ROIC Performance	Percentage Payout of ROIC Percentage*
8.90% and above	200%
8.80% 8.89%	150% 199.9%
8.70% 8.79%	100% 149.9%
8.60% 8.69%	50% 99.9%
Below 8.60%	0%

* *ROIC percentage payout is interpolated between the top and bottom of the percentages for any range.*

Book Value per Share (Book Value Performance) (10% weighting). Book Value Performance measures Dominion s value according to its balance sheet (the difference between assets and liabilities) as opposed to the market value of Dominion stock, subject to certain pre-approved exclusions, whether positive or negative, as set forth in the awards. It measures the use of funds as well as the efficiency of issuing stock. The Book Value Performance metric promotes better long-term value of Dominion assets by effective capital allocation and management and encourages a decision-making process that minimizes write-offs and issuances of stock below anticipated share prices. The CGN Committee applied a 10% weighting to this new measure in order to provide a mix of performance metrics while maintaining the desired focus on relative TSR and ROIC. Book Value Performance targets and corresponding payout scores are as follows:

Book Value Performance	Percentage Payout of Book Value Performance Percentage*
$20.80 and above	200%
$20.70 $20.79	150% 199.9%
$20.60 $20.69	100% 149.9%
$20.50 $20.59	50% 99.9%
Below $20.50	0%

* *Book Value Percentage payout is interpolated between the top and bottom of the percentages for any range.*

Vesting Terms for the 2008 Restricted Stock Grants and Performance Grants

The grants are forfeited in their entirety if an officer voluntarily terminates his or her employment or is terminated with cause before the vesting date. The grants have pro-rated vesting for termination without cause, retirement, death or disability, rewarding the officers or their estate only for the period of time they provided services to Dominion. In the case of retirement, pro-rated vesting will not occur unless the CEO (or, for the CEO, the CGN Committee) determines the officer s retirement is not detrimental to Dominion. For the performance grants, the payout is based on actual goal performance at the end of the performance cycle.

In the event of a change in control of Dominion, the restricted shares have pro-rated vesting up to the change of control date, rewarding officers only for prior service. If the officers are terminated, or constructively terminated, any remaining unvested shares will vest as of the termination date. For the performance grants, payment is made as soon as administratively feasible following the change in control date at the greater of the target amount or an amount based on predicted performance used for compensation cost disclosure purposes on Dominion s financial statements. (See also *Potential Payments upon Termination or Change in Control*).

Payout under 2007 Performance Grants

In February 2009, payouts were made to officers who received 2007 performance grants, including all of the NEOs. The 2007 performance grants were based on two evenly-weighted goals: total shareholder return for the two year period ended December 31, 2008 relative to a peer group of companies (the TSR goal) and return on invested capital (the ROIC goal).

Relative TSR goal performance was measured on the same scale set forth above for the 2008 performance grants, but the 2007 peer group for this grant did not include Ameren Corporation and DTE Energy Company.

Because of uncertainty related to Dominion s pending E&P divestitures in April 2007 when the 2007 performance grants were awarded, certain officers who at that time were potentially subject to the deduction limits imposed by Internal Revenue Code Section 162(m), including all of the NEOs except Mr. Heacock, were given awards based on a 2007 budget that excluded any assumed earnings from Dominion s E&P business unit. In order to preserve Dominion s ability to deduct the performance-based compensation paid to these officers, the CGN Committee did not have authority to modify the ROIC targets for these awards based on budget adjustments to the 2007 budget. The ROIC targets and corresponding payout scores for these officers are as follows:

ROIC Performance	Percentage Payout of ROIC Percentage*
5.9% or greater	200%
5.7% 5.89%	150% 199.9%
5.5% 5.69%	100% 149.9%
5.3% 5.49%	50% 99.9%
Below 5.3%	0%

* *ROIC percentage payout is interpolated between the top and bottom of the percentages for any range.*

Revised two-year ROIC goals for officers and employees, with the exception of the goals for officers who were potentially subject to the deduction limits imposed by Internal Revenue Code Section 162(m), were approved by the CGN Committee in 2008 based on adjustments to the 2007 budget due primarily to the impact of the E&P divestitures. The CGN Committee s discretionary authority to revise the ROIC goals was provided for under the terms of the grants. The revised ROIC targets and corresponding payout scores are as follows:

ROIC Performance	Percentage Payout of ROIC Percentage*
8.5% or greater	200%
8.3% 8.49%	150% 199.9%
8.1% 8.29%	100% 149.9%
7.9% 8.09%	50% 99.9%
Below 7.9%	0%

* *ROIC percentage payout is interpolated between the top and bottom of the percentages for any range.*

Based on the achievement of the performance criteria, the CGN Committee approved a 146% payout for the 2007 performance grants. The following table summarizes the achievement of the 2007 performance criteria:

Measure	Goal Weight%		Goal Achievement		Payout%
TSR	50%	x	116.6%	x	58%
ROIC	50%	x	176.3%	x	88%
			Combined Overall Performance Score		146%

Based on the achievement of the performance criteria for the officers who had different ROIC goals, as described above, their grant payouts would have been at a 158% level instead of the 146% level. The CGN Committee exercised negative discretion to lower the payouts for these officers by 12% so that their payouts were consistent with payouts for other officers. The resulting payout amounts for the NEOs for the 2007 Performance Grants are shown below and are also reflected in the *Non-Equity Incentive Plan Compensation* column of the *Summary Compensation Table*.

Name	2007 Performance Grant Award		Overall Performance Score		Calculated Performance Grant Payout
Thomas F. Farrell, II	$ 1,140,000	x	146%	=	$ 1,664,400
Thomas N. Chewning	440,000	x	146	=	642,400
Mark F. McGettrick	390,000	x	146	=	569,400
David A. Heacock	116,250	x	146	=	169,725
David A. Christian	159,250	x	146	=	232,505

Note: The executives included in this table may perform services for more than one subsidiary of Dominion. Compensation for the individuals listed in the table reflect only the approximate portion related to their service for Virginia Power in the year presented.

2009 Long-Term Incentive Program

In January 2009, the CGN Committee approved the 2009 long-term incentive grants for the NEOs. Dominion has not modified the design of the long-term incentive program for 2009 despite the impact of uncertain market conditions on the value of outstanding stock awards. The target award levels, terms and conditions of these grants are substantially similar to the 2008 long-term incentive grants described above, with the same TSR goals and peer group, and ROIC and Book Value goals updated to reflect Dominion s 2009-2010 business plan and consolidated operating earnings targets. The CGN Committee moved the grant date up from the early April grant date used for the 2007

and 2008 long-term incentive programs to an early February grant date. With this change to an earlier grant date, long-term incentive grants are made closer to the beginning of the performance cycle than our prior grants and shortly after the public disclosure of Dominion s earnings for the prior year. This grant date timing is also more consistent with the grant date practices of other companies in Dominion s industry.

Employee and Executive Benefits

Benefit plans and limited perquisites comprise the fourth element of Dominion s executive compensation program. These benefits serve as a retention tool and reward long-term employment.

Retirement Plans

Dominion sponsors two types of tax-qualified retirement plans: a defined benefit pension plan (the Pension Plan) and a defined contribution 401(k) savings plan (the 401(k) Plan). The NEOs, as employees hired before 2008, are eligible for a pension benefit upon attainment of retirement age based on a formula that takes into account final compensation and years of service. They also receive a cash balance benefit under which we contribute 2% of each participant s compensation to a special retirement account, which may be paid in a lump sum or added to the annuity benefit upon retirement. The formula for the Pension Plan is explained in a note to the *Pension Benefits* table. The change in pension value for 2008 for the NEOs is included in the *Summary Compensation Table*.

The matching contribution formula for the 401(k) Plan is described in a footnote to the *All Other Compensation* column of the *Summary Compensation Table*. Officers whose matching contributions are limited by Internal Revenue Code limits receive a cash payment to make them whole for the Company match lost as a result of these Internal Revenue Code limits. These cash payments are currently taxable. Our matching contributions to the 401(k) Plan and the cash payments of Company matching contributions above Internal Revenue Code limits for the NEOs are included in the *All Other Compensation* column of the *Summary Compensation Table* and detailed in the footnote for that column.

Dominion also maintains two nonqualified retirement plans for officers, the Retirement Benefit Restoration Plan (BRP) and the Executive Supplemental Retirement Plan (ESRP). Unlike the Pension Plan and 401(k) Plan, these plans are unfunded, unsecured obligations of Dominion. We believe these plans serve as strong retention tools because officers generally are not eligible for benefits if they leave Dominion before retirement age. These plans also help us be competitive in attracting and retaining officers. Because a more substantial portion of an officer s total compensation is paid as incentive compensation than for other employees, the Pension Plan and 401(k) Plan will produce a lower percentage of replacement income in retirement for officers as these plans will for other employees. The BRP and ESRP benefit formulas do not include long-term incentive compensation in benefit calculations and, therefore, a significant portion of the potential compensation for our officers is excluded from calculation in any retirement plan benefit.

As consideration for the benefits earned under the BRP and ESRP, all officers agree to comply with one-year non-competition and non-solicitation requirements set forth in the plan documents following their retirement or other termination from the Company.

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The present value of accumulated benefits under these retirement plans is disclosed in the *Pension Benefits* table and the terms of the plans are fully explained in the narrative following that table.

In individual situations and primarily for mid-career changes or retention purposes, the CGN Committee has granted certain officers additional years of credited age and service for purposes of calculating benefits under the Pension Plan and BRP. Age and service credits granted to the NEOs are described in *Additional Post-Employment Payments for NEOs* under *Potential Payments Upon Termination or Change in Control*. Additional Pension Plan benefits attributable to age and service credits will be paid from Company assets and not from the trust established for the Pension Plan. Additional age and service may also be earned under the terms of an officer s Employment Continuity Agreement in the event of a change in control, as discussed in *Change in Control* under *Potential Payments Upon Termination or Change in Control*.

Other Benefit Programs

The NEOs participate in all of the benefit programs available to Dominion employees. The core benefit programs include medical, dental, and vision benefit plans, a health savings account, health and dependent care flexible spending accounts, group-term life insurance, travel accident coverage, short-term disability and long-term disability coverage, and a paid time off program. There are other miscellaneous employee benefit programs, including employee assistance programs and employee leave policies.

Dominion also maintains an Executive Life Insurance Program for officers to replace a former company-wide retiree life insurance program that was discontinued in 2003. The plan is fully-insured by individual policies that provide death benefits equal to a multiple (one to three times) of an officer s base salary. This life insurance coverage is in addition to the group-term insurance that is provided to all employees. The officer is the owner of the policy and Dominion makes premium payments until the later of 10 years or the date the officer attains age 64. Officers are taxed on the premiums paid by Dominion. The premiums for these policies are included in the *All Other Compensation* column of the *Summary Compensation Table*.

Perquisites

Perquisites for officers are provided to enable them to perform their duties and responsibilities as efficiently as possible and to minimize distractions. The CGN Committee annually reviews the perquisites to ensure they are an effective and efficient use of corporate resources. Dominion believes the benefits we receive from offering these perquisites outweighs the costs of providing them. In addition to incidental perquisites associated with maintaining an office, Dominion offers the following perquisites to all officers:

- An allowance of up to $9,500 a year to be used for health club memberships and wellness programs, comprehensive executive physical exams and financial and estate planning. Dominion wants officers to be proactive with preventive healthcare and also wants executives to use professional, independent financial and estate planning consultants to ensure proper tax reporting of company-provided compensation and to help officers optimize their use of Dominion s retirement and other employee benefit programs.
- A Dominion-leased vehicle, including the cost of insurance, gas and maintenance, up to an established lease-payment limit (if the lease payment exceeds the allowance, the officer pays for the excess amount on the vehicle).
- In limited circumstances, use of Dominion aircraft for personal travel by executive officers. For security reasons, Dominion s Board requires Mr. Farrell to use the aircraft for all travel, including personal travel. The use of Dominion aircraft for personal travel by other executive officers is limited and usually related to (i) travel with the CEO or (ii) personal travel to accommodate business demands on an executive s schedule. Dominion also transports spouses of executives to any business meetings spouses are invited to attend. With the exception of Mr. Farrell, personal use of aircraft is not available when there is a Dominion need for the aircraft. Use of Dominion aircraft saves substantial time and allows better access to executives for business purposes. Over 97% of the use of Dominion s aircraft is for business purposes. Other than Mr. Farrell s travel and one trip by Mr. Chewning, none of the NEOs or other executive officers used Dominion aircraft for personal travel in 2008.

Other than costs associated with comprehensive executive physical exams, these perquisites are fully taxable to executives. We provide a tax gross-up for personal use of Dominion aircraft by the executive officers and their immediate family members. Effective January 1, 2009, tax gross-ups for personal use of company aircraft were discontinued. There is no tax gross-up for imputed income on other perquisites.

Employment Continuity Agreements

Dominion has entered into Employment Continuity Agreements with all officers to ensure continuity in the event of a change in control of Dominion. While Dominion has determined these agreements are consistent with the practices of its peer companies, the most important reason for these agreements is to protect Dominion in the event of an anticipated or actual change of control of Dominion. In a time of transition, it is critical to protect shareholder value by retaining and continuing to motivate Dominion s core management team. In a change in control situation, workloads typically increase dramatically, outside competitors are more likely to attempt to recruit top performers away from us, and officers and other key employees may consider other opportunities when faced with uncertainties at their own company. Therefore, the Employment Continuity Agreements provide security and protection to officers in such circumstances for the long-term benefit of the Company and Dominion and its shareholders.

In determining the appropriate multiples of compensation and benefits payable upon a change in control, Dominion evaluated peer group and general practices and considered the levels of protection necessary to retain officers in such situations. The Employment Continuity Agreements are double-trigger agreement that require both a change in control and a qualifying termination of employment to trigger a benefit. The specific terms of the Employment Continuity Agreements are discussed in *Additional Post-Employment Payments for NEOs* under *Potential Payments Upon Termination or Change in Control*.

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Other Agreements

Dominion does not have comprehensive employment agreements or severance agreements for its NEOs. Although the CGN Committee believes the compensation and benefit programs described in this Compensation Discussion and Analysis are appropriate, Dominion, as one of the nation s largest producers and transporters of energy, is part of a constantly changing and increasingly competitive environment. In recognition of their valuable knowledge and experience and to secure and retain their services, Dominion has entered into letter agreements with four of our NEOs to provide certain benefit enhancements or other protections, as described in *Additional Post-Employment Payments for NEOs* under *Potential Payments Upon Termination or Change in Control*.

Other Relevant Compensation Practices

Share Ownership Guidelines

Dominion requires officers to own and retain significant amounts of Dominion stock during their careers to align management interests with those of Dominion s shareholders. Targeted ownership levels are the lesser of the following:

Position	**Value/# of Shares**
Chairman, Dominion President & CEO	8 x salary/145,000
Executive Vice President Dominion	5 x salary/35,000
Senior Vice President Dominion & Subsidiaries/President Dominion Subsidiaries	4 x salary/20,000
Vice President Dominion & Subsidiaries	3 x salary/10,000

Shares owned by an officer and his or her immediate family members as well as shares held under Dominion benefit plans count towards the ownership targets. Restricted stock, goal-based stock and shares underlying stock options do not count towards the ownership targets. Certain types of transactions related to Dominion stock are prohibited, including derivative securities, hedging transactions, margin accounts and pledging shares as collateral.

With limited exceptions, officers are expected to retain ownership of their Dominion stock, including restricted stock and goal-based shares that have vested, as long as they remain employed by Dominion. Shares held by an officer that are more than 15% above his or her ownership target are referred to as Qualifying Excess Shares. Officers may sell up to 50% of their Qualifying Excess Shares at any time and may sell all Qualifying Excess Shares during the one-year period preceding retirement. Qualifying Excess Shares may also be gifted to a charitable organization or put into a trust outside of the officer s control for estate planning purposes at any time.

At least annually, the CGN Committee reviews the share ownership guidelines and monitors compliance by executive officers individually and the officer group as a whole. The NEOs ownership is shown in the *Share Ownership* table; each NEO exceeds his ownership target.

Recovery of Incentive Compensation

Consistent with standards established by the Sarbanes-Oxley Act of 2002, Dominion s Corporate Governance Guidelines authorize the Dominion Board to seek recovery of performance-based compensation paid to officers who are found to be personally responsible for fraud or intentional misconduct that causes a

restatement of financial results filed with the SEC. Beginning in 2009, the CGN Committee approved a broader clawback provision for inclusion in the AIP and long-term incentive performance grant documents. This clawback provision authorizes the CGN Committee, in its discretion and based on facts and circumstances, to recoup AIP and performance grant payouts from any employee whose fraudulent or intentional misconduct

(i) directly causes or partially causes the need for a restatement of a financial statement or (ii) relates to or materially affects Dominion s operations or the employee s duties at the Company. Dominion reserves the right to recover a payout by seeking repayment from the employee, by reducing the amount that would otherwise be payable to the employee under another Dominion benefit plan or compensation program to the extent permitted by applicable law, withholding future incentive compensation, or a combination of these actions. The clawback provision is in addition to, and not in lieu of, other actions that Dominion may take to remedy or discipline misconduct, including termination of employment or a legal action for breach of fiduciary duty, and any actions imposed by law enforcement agencies.

Tax Deductibility of Compensation

Section 162(m) of the Internal Revenue Code generally disallows a deduction by publicly held corporations for compensation in excess of $1 million paid to the four most highly-compensated officers other than the chief financial executive. If certain requirements are met, performance-based compensation qualifies for an exemption and is not subject to the Section 162(m) deduction limit. We intend to provide competitive executive compensation while maximizing Dominion s tax deduction. While the CGN Committee considers Section 162(m) tax implications when designing annual and long-term compensation programs and approving payouts under such programs, it reserves the right to approve, and in some cases has approved, non-deductible compensation when corporate objectives justify the cost of being unable to deduct such compensation. Dominion s Tax Department has advised the CGN Committee that the cost of any such lost tax deduction is not material to Dominion.

Accounting for Stock Based Compensation

Dominion measures and recognizes compensation expense in accordance with Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 123R), which requires that compensation expense relating to share-based payment transactions be recognized in the financial statements based on the fair value of the equity or liability instruments issued. The CGN Committee considers the accounting treatment of equity and performance-based compensation when approving awards.

SUMMARY COMPENSATION TABLE AN OVERVIEW

The Summary Compensation Table is the principal source of information regarding compensation earned by our NEOs as well as amounts accrued or accumulated during years reported with respect to retirement plans, past equity grants and other items. The NEOs include our CEO, our CFO and the three most highly compensated executives other than our CEO and CFO.

The following discussion highlights some of the disclosures contained in this table for our NEOs. Detailed explanations regarding certain types of compensation paid to an NEO are included in the footnotes to the table.

Salary. The amounts in this column are the base salaries earned by the NEOs for the years indicated.

Stock Awards. This column discloses the expense recognized for the fiscal year in accordance with SFAS 123R on all outstanding restricted stock awards granted to the NEOs. It reflects the expense recognized for outstanding stock grants made to the NEOs from grants awarded in 2004, 2006, 2007 and 2008.

Non-Equity Incentive Plan Compensation. This column includes amounts earned under two performance-based plans, the AIP and the long-term incentive program. For 2008, the amounts include the payout of cash compensation earned under the 2008 AIP as well as the payout of cash-based performance grant awards made in 2007. For 2007, the amounts include the payout of cash compensation earned under the 2007 AIP as well as the payout of cash-based performance grant awards made in 2006. For 2006, the amounts include only the payout of cash compensation earned under the 2006 AIP. In 2006, Dominion transitioned the long-term incentive program from a program based only in restricted stock grants to a program that was split between restricted stock grants and performance grants. The first long-term performance grant payout occurred for the 2006/2007 cycle and is reflected in the 2007 amount. These performance programs are based on performance criteria established by the CGN

Committee at the beginning of the performance period, with actual performance scored against the pre-set criteria by the CGN Committee at the end of the performance period.

Change in Pension Value and Nonqualified Deferred Compensation Earnings. This column shows any year-over-year increases in the annual accrual of pension and supplemental retirement benefits for the NEOs. These are accruals for future benefits that may be earned under the terms of our retirement plans, and do not reflect actual payments made during the year to our NEOs. The amounts disclosed reflect the annual change in the actuarial present value of benefits under defined benefit plans sponsored by Dominion, which include the tax-qualified Pension Plan and the nonqualified plans described in the narrative following the *Pension Benefits* table. The annual change equals the difference in the accumulated amount for the current fiscal year and the accumulated amount for the prior fiscal year, using the same actuarial assumptions used for Dominion s audited financial statements for the applicable fiscal year, including assumed retirement dates, life expectancy of our officers and other assumptions.

All Other Compensation. The amounts in this column disclose compensation that is not classified as compensation reportable in another column, including perquisites and benefits with an aggregate value of at least $10,000, the value of Dominion-paid life insurance premiums, the value of tax gross-up compensation for personal use of Dominion s aircraft by Mr. Farrell, matching contributions to an NEO 401(k) Plan account, Dominion matching contributions paid directly to the NEO that would be credited to the 401(k) Plan if Internal Revenue Code contribution limits did not apply, payment for unused vacation days not carried forward to the following year, and dividends paid on restricted stock.

Total. The number in this column provides a single figure that represents the total compensation either earned by each NEO for the years indicated or accrued benefits payable in later years and required to be disclosed by SEC rules in this table. It does not reflect actual compensation paid to the NEO during the year, but is the sum of the dollar values of each type of compensation quantified in the other columns in accordance with SEC rules.

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SUMMARY COMPENSATION TABLE

The following table represents information concerning compensation paid or earned by our NEOs for the years ended December 31, 2008, 2007 and 2006 as well as annual accruals for outstanding equity awards and changes in pension value.

Name and Principal Position	Year	Salary(1)	Stock Awards(2)	Non-Equity Incentive Plan Compensation(3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(4)	All Other Compensation(5)	Total
Thomas F. Farrell, II							
Chairman and CEO	**2008**	**$ 452,833**	**$ 1,180,671**	**$ 2,559,300**	**$ 997,551**	**$ 238,040**	**$ 5,428,395**
	2007	517,000	1,246,504	3,074,928	1,028,323	298,803	6,165,558
	2006	350,000	686,742	408,100	915,719	196,025	2,556,586
Thomas N. Chewning							
Executive Vice President and CFO	**2008**	**298,008**	**667,500**	**1,088,985**	**153,121**	**138,446**	**2,346,060**
	2007	250,380	461,861	971,107	127,083	136,243	1,946,674
	2006	180,000	311,604	171,720	88,263	112,317	863,904
Mark F. McGettrick							
President and COO Generation	**2008**	**327,253**	**372,974**	**1,061,894**	**376,799**	**87,288**	**2,226,208**
	2007	300,510	318,074	939,197	414,335	87,950	2,060,066
	2006	262,500	214,537	214,364	441,558	77,724	1,210,683
David A. Christian							
President and Chief Nuclear Officer	**2008**	**263,498**	**205,844**	**517,672**	**299,988**	**64,877**	**1,351,879**
	2007	235,908	149,465	526,972	188,455	64,818	1,165,618
	2006	206,055	126,428	149,606	146,186	52,538	680,813
David A. Heacock							
President and COO DVP	**2008**	**289,628**	**174,091**	**490,450**	**235,734**	**63,477**	**1,253,380**

Note: The executives included in this table may perform services for more than one subsidiary of Dominion. Compensation for the individuals listed in the table and related footnotes reflect only the approximate portion related to their service for Virginia Power in the year presented.

(1) *Salary increases for 2008 became effective on February 1, 2008. For the month of January 2008, monthly salary was paid at the 2007 monthly salary amount.*

(2) *The amounts in this column reflect the compensation expense recognized in 2008 on all outstanding stock awards in accordance with SFAS 123R. Dominion did not grant any stock options in 2008. The grant date fair value of each NEO s 2008 stock grant is disclosed in the Grants of Plan-Based Awards table in accordance with SFAS 123R. The grant date fair value of restricted stock awards is equal to the market price of our stock on the date of grant in accordance with SFAS 123R. See also Note 20 to the Consolidated Financial Statements in Dominion s 2008 Annual Report on Form 10-K for more information on the valuation of stock-based awards and the Outstanding Equity Awards at Fiscal Year-End table for a listing of all outstanding equity awards as of December 31, 2008.*

(3) *The 2008 amounts in this column include the payout under Dominion s 2008 AIP and 2007 Performance Grant Awards. All of the NEOs except for Mr. Christian received a 157% payout of their 2008 AIP target awards reflecting 157% fundings of the 2008 AIP and 100% accomplishment of their goals. Mr. Christian s payout was reduced due to 98% accomplishment of his goals. The payout amounts were as follows: Mr. Farrell $894,900; Mr. Chewning $446,585; Mr. McGettrick $492,494; Mr. Christian $285,167; and Mr. Heacock $320,725. See the Compensation Discussion and Analysis for additional information on the 2008 AIP and the Grants of Plan Based Awards table for the range of each NEO s potential award under the 2008 AIP. The 2007 Performance Grant Award was issued on April 3, 2007, and the payout amount was determined based on achievement of performance goals for the performance period ended December 31, 2008. The payouts could range from 0% to 200% of each NEO s target award. The 2007 Performance Grant payout was 146%. The payout amounts were as follows: Mr. Farrell $1,664,400; Mr. Chewning $642,400; Mr. McGettrick $569,400; Mr. Christian $232,505; and Mr. Heacock $169,725. The 2007 amounts reflect both the 2007 AIP and the 2006 Performance Grant payments, while the 2006 amounts reflect only the 2006 AIP payments.*

(4) *All amounts in this column are for the aggregate change in the actuarial present value of the NEO s accumulated benefit under the qualified pension plan and nonqualified executive retirement plans. There are no above-market earnings on nonqualified deferred compensation plans. These accruals are not directly in relation to final payout potential, and can vary significantly year over year based on (i) promotions and corresponding changes in salary; (ii) other one-time adjustments to salary or incentive target for market or other reasons; (iii) actual age versus predicted age at retirement; and (iv) other relevant factors.*

(5) All Other Compensation amounts for 2008 are as follows:

Name	Executive Perquisites [a]	Life Insurance Premiums	Tax Gross-up	Employee 401(k) Plan Match [b]	Company Match Above IRS Limits [c]	Vacation Sold Back to Company	Dividends Paid on Restricted Stock	Total All Other Compensation
Thomas F. Farrell, II	$ 35,657	$ 21,990	$ 5,957	$ 2,622	$ 10,963	$ 8,769	$ 152,082	$ 238,040
Thomas N. Chewning	12,406	39,426	891			5,758	79,964	138,445
Mark F. McGettrick	13,930	13,098	0	4,784	8,306		47,170	87,288
David A. Christian	16,335	11,237	458	4,508	6,032		26,308	64,878
David A. Heacock	16,261	8,871	233	8,556	3,029	5,613	20,915	63,478

(a) Unless noted, the amounts in this column for all NEOs are comprised of the following: personal use of company vehicle; financial planning and health and wellness allowance. For Messrs. Farrell and Chewning, the amounts in this column also include personal use of Dominion aircraft; Mr. Farrell s personal use of the Dominion aircraft was $24,860. For personal flights, all direct operating costs are included in calculating aggregate incremental cost. Direct operating costs include the following: fuel, airport fees, catering, ground transportation and crew expenses (any food, lodging and other costs). The fixed costs of owning the aircraft and employing the crew are not taken into consideration, as more than 97% of the use of the corporate aircraft is for business purposes. The CGN Committee has directed Mr. Farrell to use Dominion aircraft for all personal travel.

(b) Employees who contribute to the 401(k) Plan receive a matching contribution of 50 cents for each dollar contributed up to 6% of compensation (subject to IRS limits) if the employees have less than 20 years of service and 67 cents for each dollar contributed up to 6% of compensations (subject to IRS limits) if the employees have 20 or more years of service.

(c) Represents each payment of lost 401(k) Plan matching contribution due to Internal Revenue Code limits.

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GRANTS OF PLAN-BASED AWARDS

The following table provides information about stock awards and non-equity incentive awards granted to our NEOs during the year ended December 31, 2008.

Name	Grant Date	Grant Approval Date[1]	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1] Threshold	Target	Maximum	All Other Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Stock and Options Award[1]
Thomas F. Farrell, II							
2008 Annual Incentive Plan[2]			$ 0	$ 570,000	$ 1,140,000		
2008 Performance Grant[3]			$ 0	$ 1,140,000	$ 2,280,000		
2008 Restricted Stock Grant[3]	4/1/2008	3/27/2008				27,914	$ 1,140,009
Thomas N. Chewning							
2008 Annual Incentive Plan[2]			$ 0	$ 284,449	$ 568,898		
2008 Performance Grant[3]			$ 0	$ 440,000	$ 880,000		
2008 Restricted Stock Grant[3]	4/1/2008	3/27/2008				10,774	$ 440,003
2008 Restricted Stock Retention Grant[4]	4/1/2008	3/27/2008				10,744	440,003
Mark F. McGettrick							
2008 Annual Incentive Plan[2]			$ 0	$ 313,690	$ 627,380		
2008 Performance Grant[3]			$ 0	$ 390,000	$ 780,000		
2008 Restricted Stock Grant[3]	4/1/2008	3/27/2008				9,550	$ 390,014
David A. Christian							
2008 Annual Incentive Plan[2]			$ 0	$ 185,323	$ 370,646		
2008 Performance Grant[3]			$ 0	$ 159,250	$ 318,500		
2008 Restricted Stock Grant[3]	4/1/2008	3/27/2008				3,899	$ 159,252
David A. Heacock							
2008 Annual Incentive Plan[2]			$ 0	204,284	408,568		
2008 Performance Grant[3]			$ 0	162,750	325,500		
2008 Restricted Stock Grant[3]	4/1/2008	3/27/2008				3,986	$ 162,787

Note: The executives included in this table may perform services for more than one subsidiary of Dominion. Compensation for the individuals listed in the table and related footnotes reflect only the approximate portion related to their service for Virginia Power in the year presented.

(1) *On March 27, 2008, the CGN Committee approved the 2008 long-term compensation awards for our officers, which consisted of a restricted stock grant and a performance grant. The 2008 restricted stock award was granted on April 1, 2008. Under our 2005 Incentive Compensation Plan, fair market value is defined as the closing price of Dominion stock as of the last day on which the stock is traded preceding the date of grant. The fair market value for the April 1, 2008 restricted stock grant was $40.84 per share, which was Dominion s closing stock price on March 31, 2008.*

(2) *The amounts in these rows represent potential payouts under the 2008 AIP. Actual payouts earned are reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table. Under our AIP officers are eligible for an annual performance-based award. The CGN Committee establishes target awards for each executive officer based on his or her salary level and expressed as a percentage of the individual executive s base salary. The target award is the amount of cash that will be paid if the plan is fully funded and payout goals are achieved. For the 2008 AIP, funding is based on the achievement of consolidated operating earnings goals with the maximum funding capped at 200%, as explained in Annual Incentive Plan of the Compensation Discussion and Analysis.*

For our officers who are among Dominion s top most highly compensated group for 2008, which includes all of our NEOs, pay-out under the 2008 AIP is based solely on the achievement of the funding goals, with the CGN Committee having the discretion to lower actual payouts to ensure that such awards are consistent with those granted to other plan participants. The 2008 target percentages of base salary for our NEOs are as follows: Mr. Farrell 125%; Messrs. Chewning and McGettrick 95%; Mr. Christian and Mr. Heacock 70%. The CGN Committee exercised negative discretion to lower Mr. Christian s actual payout, as discussed in 2008 AIP Payouts section of the Compensation Discussion and Analysis.

(3) *The 2008 restricted stock grant fully vests at the end of three years with dividends paid during the restricted period at the same rate declared by Dominion for its shareholders. The restricted stock grant also provides for pro-rata vesting if an officer dies, become disabled, retires, is terminated without cause or if there is a change in control.*

The 2008 performance grant will be paid in cash in 2010 and can range from 0 to 200% of the target award. The amount earned by our officers will depend on the level of achievement of three performance metrics: Total Shareholder Return (TSR) 50%, Return on Invested Capital (ROIC) 40% and Book Value per Share (Book Value Performance) 10%. TSR will measure Dominion s share performance for the two-year period ended December 31, 2009 relative to the TSR of a group of industry peers selected by the CGN Committee. ROIC goal achievement will be scored against 2008 and 2009 budget goals. Book Value Performance will measure Dominion s value according to its balance sheet as opposed to the market value of Dominion stock.

The target performance and payout percentages for TSR, ROIC and Book Value Performance can be found in the 2008 Cash Performance Grants section of the Compensation Discussion and Analysis.

(4) On April 1, 2008, the CGN Committee awarded Mr. Chewning 10,744 shares of restricted stock for retention purposes. These shares will fully vest on April 1, 2010 provided Mr. Chewning remains employed until that date. Dividends on the restricted shares are paid during the restricted period at the same rate declared by Dominion for its shareholders. The grant provides for pro-rata vesting if Mr. Chewning dies, becomes disabled, or is terminated without cause, or if there is a change in control. The grant agreement provides that the CGN Committee, in its sole discretion, may provide pro-rata vesting of the restricted shares upon Mr. Chewning s retirement before April 1, 2010.

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OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

The following table summarizes the equity awards we have made to our NEOs that were outstanding as of December 31, 2008.

	Option Awards			Stock Awards	
Name	Number of Securities Underlying Unexercised Options Exercisable(1)	Option Exercise Price	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested(2)
Thomas F. Farrell, II	152,000	$ 29.98	1/1/2010	17,049(3)	$ 611,036
				32,791(4)	1,175,229
				25,478(5)	913,132
				27,914 (6)	1,000,438
Thomas N. Chewning	132,000	$ 29.98	1/1/2010	11,958(3)	428,575
				12,657(4)	453,627
				9,834(5)	352,451
				10,774(6)	386,104
				10,774 (7)	386,104
Mark F. McGettrick				5,000(3)	179,200
				8,975(4)	321,664
				8,716(5)	312,381
				9,549 (6)	342,236
David A. Christian				4,581(4)	164,183
				3,559(5)	127,555
				3,899(6)	139,740
				3,213(8)	115,154
				2,371 (9)	84,977
David A. Heacock				3,344(4)	119,849
				2,598(5)	93,112
				3,985(6)	142,822
				2,287(8)	81,966
				1,153 (10)	41,324

Note: The executives included in this table may perform services for more than one subsidiary of Dominion. Compensation for the individuals listed in the table and related footnotes reflect only the approximate portion related to their service for Virginia Power in the year presented.

(1) *All options presented in this table are fully vested and exercisable. There are no unexercisable options outstanding.*
(2) *Based on closing stock price of $35.84 on December 31, 2008, which was the last day of our fiscal year on which Dominion stock was traded.*
(3) *Shares vest on May 11, 2009.*
(4) *Shares vest on April 1, 2009.*
(5) *Shares vest on April 3, 2010.*
(6) *Shares vest on April 1, 2011.*
(7) *Shares vest on April 1, 2010.*
(8) *Shares vest on February 18, 2009.*
(9) *Shares vest on December 20, 2009.*
(10) *Shares vest on December 1, 2009.*

Option Exercises And Stock Vested

The following table provides information about the value realized by our NEOs on option award exercises and stock awards vesting during the year ended December 31, 2008.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise	Number of Shares Acquired on Vesting	Value Realized on Vesting
Thomas F. Farrell, II	152,000(1)	$ 1,742,403	31,813	$ 1,344,736
Thomas N. Chewning	132,000(1)	1,512,532	26,605	1,124,593
Mark F. McGettrick			11,125	470,254
David A. Christian			7,293	308,275
David A. Heacock			6,821(2)	261,840

Note: The executives included in this table may perform services for more than one subsidiary of Dominion. Compensation for the individuals listed in the table and related footnotes reflect only the approximate portion related to their service for Virginia Power in the year presented.

(1) These options were exercised pursuant to a Rule 10b5-1 trading plan.

(2) Shares vested on two different dates 1,239 shares vested on December 1, 2008 with a realized value of $36.82 per share. 5,582 shares vested on February 24, 2008 with a realized value of $42.27 per share.

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PENSION BENEFITS[1]

The following table shows the present value of accumulated benefits payable to our NEOs under the plans listed in the table. No payments were made to any of the named executive officers during the year ended December 31, 2008 under any of the plans listed in the table.

Name	Plan Name	Number of Years Credited Service[2]	Present Value of Accumulated Benefit ($)
Thomas F. Farrell, II	Pension Plan	13.00	101,359
	Benefit Restoration Plan (Pre-2005)	9.00	167,680
	Supplemental Retirement Plan (Pre-2005)	9.00	1,727,360
	New Benefit Restoration Plan (Post 2004)	23.21	1,190,484
	New Supplemental Retirement Plan (Post 2004)	23.21	2,840,313
Thomas N. Chewning	Pension Plan	21.00	339,465
	Benefit Restoration Plan (Pre-2005)	25.00	1,350,837
	Supplemental Retirement Plan (Pre-2005)	25.00	1,749,044
	New Benefit Restoration Plan (Post 2004)	30.00	351,993
	New Supplemental Retirement Plan (Post 2004)	30.00	484,866
Mark F. McGettrick	Pension Plan	24.50	215,115
	Benefit Restoration Plan (Pre-2005)	20.50	124,750
	Supplemental Retirement Plan (Pre-2005)	20.50	196,316
	New Benefit Restoration Plan (Post 2004)	29.50	1,250,614
	New Supplemental Retirement Plan (Post 2004)	29.50	1,020,262
David A. Christian	Pension Plan	24.50	253,916
	Benefit Restoration Plan (Pre-2005)	20.50	144,558
	Supplemental Retirement Plan (Pre-2005)	20.50	270,286
	New Benefit Restoration Plan (Post 2004)	24.50	387,824
	New Supplemental Retirement Plan (Post 2004)		

		24.50	991,528
David A. Heacock	Pension Plan	21.50	323,304
	Benefit Restoration Plan (Pre-2005)	17.50	n/a
	Supplemental Retirement Plan (Pre-2005)	17.50	139,381
	New Benefit Restoration Plan (Post 2004)	21.50	n/a
	New Supplemental Retirement Plan (Post 2004)	21.50	771,920

Note: The executives included in this table may perform services for more than one subsidiary of Dominion. Compensation for the individuals listed in the table and related footnotes reflect only the approximate portion related to their service for Virginia Power in the year presented.

(1) The years of credited service and the present value of accumulated benefits were determined by our plan actuaries, using the appropriate accrued service and pay and other assumptions similar to those used for accounting and disclosure purposes.

(2) Years of credited service for the Pension Plan are actual years accrued by the executive from his date of participation to December 31, 2008. Years of credited service for the Pre-2005 Plans is accrued service from date of participation up to December 31, 2004. Service for the Benefit Restoration Plan Post-2004 and the Supplemental Retirement Plan Post-2004 is the executive s potential total service, including extra years of credited service granted to the executive by the CGN Committee for purposes of calculating benefits under these plans, times a fraction equal to service from the date of participation until the age when maximum credited service would be earned. Please refer to the Employee and Executive Benefits section of the Compensation Discussion and Analysis for information about the requirements for receiving extra years of credited service and the amount credited for each NEO.

Dominion Pension Plan

The Dominion Pension Plan is a tax-qualified defined benefit pension plan. All named executive officers are participants in the Pension Plan.

The Pension Plan provides unreduced retirement benefits at termination of employment at or after age 65 or, with three years of service, at age 60. Reduced retirement is available after age 55 with three years of service. For retirement between ages 55 and 60, the benefit is reduced 0.25% per month for each month after age 58 and before age 60 and 0.50% per month for each month between ages 55 and 58. All named executive officers have more than three years of service.

The Pension Plan basic benefit is calculated using a formula based on (1) age at retirement; (2) final average earnings; (3) estimated Social Security benefits; and (4) credited service. Final average earnings are the average of the participant s 60 highest consecutive months of base pay during the last 120 months worked. Earnings are limited to the IRS maximum which was $230,000 for 2008. Bonuses are not included in base pay.

Credited service is measured in months, up to a maximum of 30 years of credited service. The estimated Social Security benefit taken into account is the assumed Social Security benefit payable starting at age 65 or actual retirement date, if later, assuming that the participant has no further employment after leaving Dominion.

These factors are then applied in a formula. The formula has different percentages for credited service before 2001 and after 2000. The benefit is the sum of the amounts from these two formulas.

	For Credited Service through December 31, 2000:	
2.03% **times** Final Average Earnings **times** Credited Service before 2001	**Minus**	2.00% **times** estimated Social Security benefit **times** Credited Service before 2001
	For Credited Service on or after January 1, 2001:	
1.80% **times** Final Average Earnings **times**	**Minus**	1.50% **times** estimated Social Security benefit **times** Credited Service after 2000

Credited Service after 2000

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Credited Service is limited to a total of 30 years for all parts of the formula and Credited Service after 2000 is limited to 30 years minus Credited Service before 2001. Benefit payment options are a (1) single life annuity; or (2) 50%, 75% or 100% joint and survivor annuity. A Social Security leveling option is available with any of the benefit forms. The normal form of benefit is the single life annuity for unmarried participants and a 50% joint and survivor annuity for married participants. All of the options are the actuarial equivalent of the single life annuity. The Social Security leveling option pays a larger benefit equal to the estimated Social Security benefit until the participant is age 62 and then reduced payments after age 62.

The Pension Plan also includes a Special Retirement Account (SRA), which is in addition to the pension benefit. The SRA is credited with 2% of base pay each month beginning in 2001 as well as interest based on the 30-year Treasury bond rate set annually. The SRA can be paid in a lump sum or paid as part of an annuity with the other benefits under the Pension Plan.

A vested participant who terminates employment before age 55 can start receiving benefit payments at any time after attaining age 55. If payments begin before age 65, then the following reduction factors for the portion of the benefits earned after 2000 apply: age 64 9%; age 63 16%; age 62 23%; age 61 30%; age 60 35%; age 59 40%; age 58 44%; age 57 48%; age 56 52%; and age 55 55%.

Dominion Benefit Restoration Plans

Dominion sponsors the New Benefit Restoration Plan, effective as of January 1, 2005 (New BRP), and the Frozen Benefit Restoration Plan, frozen as of December 31, 2004 (Frozen BRP). Neither plan is tax-qualified.

The Frozen BRP provides benefits accrued before 2005 that are intended to be exempt from Section 409A of the Internal Revenue Code. The New BRP was adopted to accommodate the enactment of and is intended to comply with Section 409A of the Internal Revenue Code for benefits accrued after 2004. The overall restoration benefit was not changed by adoption of the New BRP.

A Dominion employee is eligible to participate in the New BRP if he or she is a member of management or a highly compensated employee, has had his or her benefit under the Dominion Pension Plan reduced or limited by the Internal Revenue Code, and has been designated as a participant by the CGN Committee. The CGN Committee has designated all elected officers as participants in the New BRP. The Frozen BRP has been closed to new participants since December 31, 2004. A participant remains a participant in either plan until he or she ceases to be eligible for any reason other than retirement or until his or her status as a participant is revoked by Dominion.

Upon retirement, the New BRP provides a monthly restoration benefit equal to the monthly benefit the participant would have received under Dominion s Pension Plan but for the limitations imposed by the Internal Revenue Code, reduced by the monthly benefit the participant actually receives under Dominion s Pension Plan, reduced further by the monthly benefit the participant receives under the Frozen BRP. Upon retirement, the Frozen BRP provides a monthly restoration benefit equal to the monthly benefit the participant would have received under Dominion s Pension Plan but for the limitations imposed by the

Internal Revenue Code, reduced by the monthly benefit the participant actually receives under Dominion s Pension Plan, in each case determined as though the participant had separated from service with Dominion no later than December 31, 2004.

As discussed above, the Internal Revenue Code limits the amount of compensation that may be taken into account under a qualified retirement plan to no more than a certain amount each year. For 2008, the limit was $230,000. The Internal Revenue Code also limits the total annual benefit that may be provided to a participant under a qualified defined benefit plan. For 2008, this limitation was the lesser of (i) $185,000 or (ii) the average of the participant s compensation during the three consecutive years in which the participant had the highest aggregate compensation.

In each plan, retirement means the participant s termination of employment with Dominion at a time when the participant is entitled to receive benefits under Dominion s Pension Plan. If a participant dies when he or she is retirement eligible (age 55), the participant s beneficiary will receive the restoration benefit.

A participant s accrued restoration benefit is calculated based on the default annuity form under Dominion s Pension Plan. Under the New BRP, the restoration benefit is paid in the form of a single cash lump sum. Under the Frozen BRP, the restoration benefit is usually paid in the form of a single cash lump sum, unless the participant elects to receive a single life or 50% or 100% joint and survivor annuity.

Dominion Executive Supplemental Retirement Plans

Dominion sponsors the New Executive Supplemental Retirement Plan, effective as of January 1, 2005 (New ESRP), and the Frozen Executive Supplemental Retirement Plan, frozen as of December 31, 2004 (Frozen ESRP). Neither plan is tax-qualified.

The Frozen ESRP provides benefits accrued before 2005 that are intended to be exempt from Section 409A of the Internal Revenue Code. The New ESRP was adopted specifically to accommodate the enactment of and is intended to comply with Section 409A of the Internal Revenue Code for benefits accrued after 2004. The overall supplemental retirement benefit was not changed by adoption of the New ESRP.

Any elected officer of the Company is eligible to participate in the New ESRP. The CGN Committee designates an officer to participate. The Frozen ESRP has been closed to new participants since December 31, 2004. A participant remains a participant in either plan until he or she ceases to be an elected officer or until participation is revoked by Dominion.

The New ESRP provides for an annual retirement benefit equal to 25% of a participant s final cash compensation, reduced by the annual retirement benefit provided under the Frozen ESRP. The Frozen ESRP provides for an annual retirement benefit equal to 25% of a participant s final cash compensation, as of December 31, 2004. The retirement benefit is payable for only 10 years unless the CGN Committee designates the participant to receive lifetime benefits as described below.

A participant s final cash compensation includes, as of the relevant determination date, the participant s annual rate of base salary then in effect plus the target amount payable under Dominion s annual incentive plan for the year in which the determination is made. Final cash compensation does not include the value of equity awards, gains from the exercise of stock options, long-term cash incentive awards, perquisites or any other form of compensation.

A participant in either plan is entitled to the full retirement benefit if he or she separates from service with Dominion after attaining age 55 and achieving 60 months of service. Months of service generally include any months of service with Dominion, except that, for new participants who join the New ESRP on or after December 1, 2006, months of service only include months of service with Dominion while a participant in the New ESRP. Mr. Chewning and Mr. McGettrick are currently the only NEOs entitled to a full ESRP retirement benefit.

A participant who separates from service with Dominion with at least 60 months of service but who has not yet reached age 55 is entitled to a reduced ESRP benefit, calculated by multiplying the full ESRP benefit described above by a fraction, the numerator of which equals the participant s total number of months of service since becoming a participant, and the denominator of which equals the total number of months between the date the participant became a participant and age 55. Partial months are disregarded in this calculation. Messrs. Farrell, Christian and Heacock currently are not entitled to a full ESRP benefit.

A participant who separates from service with Dominion with fewer than 60 months of service is generally not entitled to an ESRP benefit. However, a participant who becomes totally and permanently disabled prior to separation from service is entitled to a full ESRP benefit, regardless of age or months of service. In addition, the beneficiary of a participant who dies prior to reaching retirement eligibility is entitled to the participant s full ESRP benefit.

A participant s ESRP benefit is initially calculated as an annual amount payable in monthly installments for a period of 120 months. However, under the terms of the ESRP, Dominion may designate certain participants as eligible for a retirement calculated as a benefit payable for their lifetimes. Messrs. Farrell and Chewning will receive an ESRP benefit calculated as lifetime benefit. Messrs. McGettrick and Christian will receive ESRP benefits calculated as lifetime benefits if they remain employed with us until attainment of age 60. See the discussion in *Additional Post Employment Benefits for Named Executive Officers* Under *Potential Payments Upon Termination or Change in Control.*

Under the New ESRP, the benefit is paid in the form of a single cash lump sum. Under the Frozen ESRP, the benefit is usually paid in the form of a single cash lump sum unless the participant elects monthly installments guaranteed for 120 months, or unless a lifetime participant elects a single life annuity with 120 guaranteed monthly payments. The lump sum calculation includes an amount approximately equivalent to the amount of taxes the participant will owe on the lump sum payment so that the participant will have sufficient funds, on an after-tax basis, to purchase a 10-year or lifetime annuity contract with the payment proceeds.

Actuarial Assumptions Used to Calculate Pension Benefits

Actuarial assumptions used to calculate Pension Plan benefits are prescribed by the terms of the Plan based on Internal Revenue Code and Pension Benefit Guaranty Corporation requirements. The present value of the accumulated benefit is calculated using actuarial and other factors as determined by the plan actuaries and approved by Dominion s Administrative Benefit Committee. Actuarial assumptions used for December 31, 2008 calculations (as shown in the Pension Benefits table) use a discount rate of

6.60% to determine the present value of the benefit obligation for the pension plan, the BRP and the ESRP. Other actuarial assumptions used include Frozen BRP and Frozen ESRP lump sum rate of 3.87%; New BRP and New ESRP lump sum rate of 5.85%; Frozen BRP cost of living adjustment of 1.625%; and the 1994 Group Annuity Mortality tables for post-retirement only. Dominion currently uses a 4% discount rate to determine the lump sum payout amounts for BRP and ESRP benefits. The discount rate for calculating lump sum payments is selected by the Administrative Benefits Committee and adjusted periodically.

NONQUALIFIED DEFERRED COMPENSATION

Name	Aggregate

	Aggregate Earnings in Last FY (as of 12/31/08)	Balance at Last FYE (as of 12/31/2008)
Thomas F. Farrell, II	$ 1,360	$ 50,811
Thomas N. Chewning	(1,781)	6,497
Mark F. McGettrick	(100,594)	392,348
David A. Christian	639	12,664
David A. Heacock	0	0

Note: The executives included in this table may perform services for more than one subsidiary of Dominion. Compensation for the individuals listed in the table reflect only the approximate portion related to their service for Virginia Power in the year presented.

Dominion does not currently offer any nonqualified elective deferred compensation plans to its officers or other employees. The Nonqualified Deferred Compensation table reflects, in aggregate, the plan balances for two former plans offered to Dominion officers and other highly compensated employees: The Dominion Resources, Inc. Executives Deferred Compensation Plan, which was frozen as of December 31, 2004 (Frozen Deferred Compensation Plan); and The Dominion Resources, Inc. Security Option Plan, which was frozen as of December 31, 2004 (Frozen DSOP). While the Frozen DSOP was not a deferred compensation plan, but an option plan, we are including information regarding the plan and any balances in this table to make full disclosure about possible future payments to officers under the employee benefit plans.

The Frozen Deferred Compensation Plan includes amounts previously deferred from one of the following categories of compensation: (i) salary; (ii) bonus; (iii) vesting restricted stock; and (iv) gains from stock option exercises. The plan also provided for company contributions of lost company 401(k) Plan match contributions and transfers from several CNG deferred compensation plans. The Frozen Deferred Compensation Plan provides for 28 investment funds for the plan balances, including a Dominion Stock Fund. Participants may change investment elections on any business day. Any vested restricted stock and gain from stock option exercises that were deferred are kept in the Dominion Stock Fund. Earnings are calculated based on the performance of the underlying investment fund. No preferential earnings are paid, and therefore no earnings from these plans are included in the *Summary Compensation Table*.

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The NEOs invested in the following funds with rates of returns for 2008 as noted below. The Vanguard 500 Index Fund has the same rate of return as the corresponding publicly available mutual fund.

Vanguard 500 Index	-37.0%
Dominion Resources Stock Fund	-21.5%
Dominion Fixed Income Fund	5.00%

The Dominion Fixed Income Fund is an option that provides a fixed return rate set prior to the beginning of the year. Dominion s Asset Management Committee determines the rate based on its estimate of the rate of return on Dominion assets in the trust for the Frozen Deferred Compensation Plan.

Under the terms of the Frozen Deferred Compensation Plan, participants may elect the following Benefit Commencement Dates:

- In February after the calendar year in which they terminate employment due to retirement;
- In February after the calendar year in which they terminate employment due to retirement, but not before February of a specific calendar year; or
- In February of a specific calendar year.

The default Benefit Commencement Date is February 1 after the year in which the participant retires. Participants may elect multiple Benefit Commencement Dates; however, all new elections must be made at least six months before an existing Benefit Commencement Date. Withdrawals less than six months prior to an existing Benefit Commencement Date are subject to a 10% early withdrawal penalty. Account balances must be fully paid out no later than February 28, 10 calendar years after a participant retires or becomes disabled. If a participant retires from Dominion he or she may continue to defer an account balance provided that the total balance is distributed by this deadline. In the event of termination of employment, for reasons other than death, disability or retirement, before an elected Benefit Commencement Date, benefit payments will be distributed in a lump sum as soon as administratively practicable. Hardship distributions, prior to an elected Benefit Commencement Date, are available under certain limited circumstances.

Participants may elect to have their benefit paid in a lump sum payment or equal annual installments over a period of whole years from one to 10 years. Participants have the ability to change their distribution schedule for benefits under the plan with six months notice to the plan administrator. Once they begin receiving annual installment payments, they can make a one-time election to either (1) receive their remaining account balance in the form of a lump sum distribution or (2) change their remaining installment payment period. Any election must be approved by Dominion before it is effective. All distributions are made in cash with the exception of the Deferred Restricted Stock Account and the Deferred Stock Option Account, which are distributed in the form of Dominion common stock.

The Frozen DSOP enabled employees to defer all or a portion of their salary and bonus and receive options on various mutual funds. Participants also received lost company matching contributions to the 401(k) Plan in the form of options under this plan. DSOP Options can be exercised at any time before their expiration date. On exercise, the participant receives the excess of the value, if any, of the underlying mutual funds over the strike

price. The participant can currently choose among options on 27 mutual funds, and there is not a Dominion stock alternative or a fixed income fund. Participants may change options among the mutual funds on any business day. Benefits grow/decline based on the total return of the mutual funds selected. Any options that expire do not have any value. Options expire under the following terms:

- Options expire on the last day of the 120th month after retirement or disability;
- Options expire on the last day of the 24th month after the participant s death (while employed);
- Options expire on the last day of the 12th month after the participant s severance;
- Options expire on the 90th day after termination with cause; and
- Options expire on the last day of the 120th month after severance following a change in control.

The named executive officers held options on the following publicly available mutual funds, which had the rates of returns for 2008 as noted.

Vanguard Short-Term Bond Index	5.4%
Vanguard Small Cap Growth Index	-40.0%
Vanguard U.S. Value	-34.8%
Artisan International Investor	-47.0%
Harbor International Fund	-42.7%
Janus Growth & Income Fund	-42.5%
Perkins Mid Cap Value Investor *(formerly Janus Mid Cap Value Fund)*	-27.3%

Potential Payments Upon Termination Or Change In Control

Under certain circumstances, Dominion provides benefits to eligible employees upon termination of employment, including a termination of employment involving a change in control of the Company, that are in addition to termination benefits for other employees in the same situation. This section describes and explains these benefits generally, and specifically the incremental benefits that pertain to our NEOs.

Review of Executive Benefits

An officer who terminates employment after he or she has attained age 55 is eligible to receive a full payment of vested benefits under the BRP and the and the ESRP. No BRP benefit is payable if an officer terminates employment before age 55. If an officer becomes disabled or dies before age 55, the officer or his beneficiary will be entitled to payment of ESRP benefits as if the officer had attained age 55, was fully vested in the benefits and retired. An officer who voluntarily terminates employment before attaining age 55 and who is vested is entitled to a prorated benefit under the ESRP. In consideration for these benefits, officers agree to a one-year non-competition and non-solicitation agreement with Dominion.

Certain officers have been designated by the CGN Committee as life participants for purposes of calculating their benefits under the ESRP; this means the benefit is calculated as a benefit payable for life, instead of as a benefit payable for 120 months. Messrs. Farrell and Chewning are life participants. The actuarial present value of the BRP, and ESRP benefits (using unreduced normal retirement age assumptions) for the NEOs is disclosed in the *Pension Benefits* table.

Restricted stock and performance-based awards granted in 2006, 2007 and 2008 will become vested on a pro-rated basis if the officer terminates employment before the vesting date due to death, disability, retirement, or an involuntary termination without cause. Restricted stock awards granted to officers before 2006 become fully vested when the officer retires with eligibility for benefits under our Pension Plan.

Employees (officers and other employees) who were hired before 2008 who have both (i) completed 10 years of service and (ii) attained age 55 are eligible to participate in Dominion s retiree medical plan.

Change in Control

As discussed in the *Employee Benefits and Executive Benefits* section of the *Compensation Discussion and Analysis*, Dominion has entered into an Employment Continuity Agreement with each of its officers, including the NEOs. Each agreement has a three-year term and is automatically extended annually for an additional year, unless cancelled by Dominion.

The Employment Continuity Agreements require two triggers for the payment of most benefits:

- There must be a change in control; and
- The executive must either be terminated without cause, or terminate his or her employment with the surviving company after a constructive termination. Constructive termination means the executive s salary, incentive compensation or job responsibility is reduced after a change in control, or the executive s work location is relocated more than 50 miles without his or her consent.

For purposes of the Employment Continuity Agreements, a change in control will occur 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, merger or other business combination, 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.

If an executive s employment following a change in control is terminated without cause or due to a constructive termination, the executive will become entitled to the following termination benefits:

- Lump sum severance payment equal to three times base salary plus annual incentive plan bonus (determined as the greater of (i) the target annual bonus for the current year or (ii) the highest actual bonus amount paid for any one of the three years preceding the year in which the change in control occurs).
- Full vesting of benefits under ESRP and BRP Plans with five years of additional credited age and five years of additional credited service from the change in control date.
- Group-term life insurance: If the officer elects to convert group-term insurance to an individual policy, we pay the premiums for 12 months.
- Executive life insurance: Premium payments will continue to be paid by us until the earlier of: (1) the fifth anniversary of the termination date, or (2) the later of the 10th anniversary of the policy or the date the officer attains age 64.
- Retiree medical coverage will be determined under the relevant plan with additional age and service credited as provided under an officer s letter of agreement (if any) and including five additional years credited to age and five additional years credited to service.
- Outplacement services for one year (or $25,000).
- If any payments are classified as excess parachute payments for purposes of Internal Revenue Code Section 280G and the executive incurs the excise tax, we will pay the executive an amount equal to the 280G excise tax plus a gross-up multiple.

The terms of awards made under the Long-Term Incentive Program, rather than the terms of Employment Continuity Agreements, will determine the vesting of each award in the event of a change in control. These provisions are described in the *Long-Term Incentive Program* section of the *Compensation Discussion and Analysis*.

The table below provides the payments that would be earned by each NEO if his employment was terminated, or constructively terminated, as of December 31, 2008 as a result of a change in control. Mr. Chewning is retirement eligible and these benefits would be in addition to the retirement benefits disclosed in the *Pension Benefits* table. For the other NEOs these benefits are in addition to the benefits they would receive for a termination without cause as discussed below. All stock options held by our NEOs are vested. In the event of a change in control, outstanding options could be exercised or the CGN Committee may take actions with respect to unexercised options that it deems appropriate.

Additional Post-Employment Benefits for NEOs

Under the terms of letter agreements with Messrs. Farrell, Chewning, McGettrick and Christian the following benefits are available in addition to the benefits described above. These benefits are quantified in the table below, assuming the triggering event set forth in the table occurred on December 31, 2008.

Mr. Farrell. Mr. Farrell has earned a lifetime benefit under the ESRP. For purposes of calculating his benefits under the Pension Plan and BRP, Mr. Farrell will be credited with 25 years of service if he remains employed until he attains age 55, and he will be credited with 30 years of service if he remains employed until he attains age 60. If Mr. Farrell is involuntarily terminated without cause before he attains age 55, he will be entitled to participate in Dominion s retiree medical plan to the same extent as retired employees under the terms of the retiree medical plan in effect as of the involuntary termination date. In addition, an unvested restricted stock granted to Mr. Farrell in 2004 before he became CEO will become vested on his involuntary termination date; this restricted stock award is scheduled to vest in May 2009. These benefits were provided in connection with his election as CEO.

Mr. Farrell will become entitled to a payment of one times salary upon his retirement as consideration for his agreement not to compete with Dominion for a two-year period following retirement. This agreement ensures that his knowledge and services will not be available to competitors for two years following his retirement date.

Mr. Chewning. Mr. Chewning will also become entitled to a payment of one times salary upon his retirement as consideration for his agreement not to compete with Dominion for a two-year period following retirement to ensure that his knowledge and services will not be available to competitors for two years following his retirement date. Mr. Chewning has earned a lifetime benefit under the ESRP. Under the terms of a retention agreement, Mr. Chewning has earned 30 years of credited service for purposes of calculating his Pension Plan and Retirement Benefit Restoration Plan benefits as he has met the requirement of remaining employed until he attained age 60. For retention purposes, in April 2008 the CGN Committee granted a restricted stock award to Mr. Chewning with an April 2010 vesting date. The terms of this retention grant are fully described in a footnote to the *Grants of Plan Based Awards* table.

Mr. McGettrick. Mr. McGettrick will earn a lifetime benefit under the ESRP if he remains employed until he attains age 60. Under the terms of a retention arrangement, he has earned five years of additional age and service credit for purposes of comput-

ing his Pension Plan and BRP benefits and eligibility for benefits under the ESRP, long-term incentive grants, and retiree medical and life insurance plans as he has met the requirement of remaining employed until he attained age 50. If Mr. McGettrick terminates employment before he attains age 55, he will be deemed to have retired for purposes of determining his vesting credit under the terms of his restricted stock and performance grant awards.

Messrs. Heacock and Christian. Mr. Heacock and Mr. Christian are not retirement eligible as of December 31, 2008. Their benefits under the BRP and ESRP are disclosed in the *Pension Benefits* table. With the exception of benefits payable upon a termination following a change in control, as of December 31, 2008, Messrs. Heacock and Christian are not entitled to any enhanced benefits under these plans. The incremental benefits payable under these plans as of December 31, 2008 if Messrs. Heacock and Christian had terminated employment following a change in control, had died or became disabled are disclosed in the table below. Mr. Christian will earn a lifetime benefit under the ESRP if he remains employed until he attains age 60.

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Incremental Payments Upon Termination and Change in Control

	Non-Qualified Plan Payment	Restricted Stock (1)	Performance Grant	Non-Compete Payments (2)	Severance Payments	Retiree Medical & Executive Life Insurance (3)	Outplacement Services	Excise Tax & Tax Gross-Up	Total
Thomas F. Farrell, II									
Termination Without Cause		2,471,578	488,826			52,384			3,012,788
Voluntary Termination									0
Termination With Cause									0
Death / Disability		1,859,567	488,826						2,348,393
Change In Control (4)	2,506,518	1,228,296	651,178		4,106,736	21,990	9,500	3,693,499	12,217,717
Thomas N. Chewning (5)									
Retirement	264,914	862,686	188,670	299,420		85,943			1,701,633
Change In Control (4)		715,662	251,330		2,363,484				3,330,476
Mark F. McGettrick									
Termination Without Cause	924,426	562,455	167,230			77,627			1,731,738
Voluntary Termination	924,426								924,426
Termination With Cause									0
Death / Disability	924,426	562,455	167,230						1,654,111
Change In Control (4)	810,044	413,872	222,770		2,463,349	13,098	13,000	1,746,112	5,682,245
David A. Heacock									
Termination Without Cause		228,563	69,786						298,349
Voluntary Termination									0
Termination With Cause									0
Death / Disability	215,509	228,563	69,786						513,858
Change In Control (4)	1,662,609	250,606	92,964		1,599,951	149,259	23,250	1,555,072	5,333,711
David A. Christian									
Termination Without Cause		317,342	68,285						385,627
Voluntary Termination									0
Termination With Cause									0
Death / Disability		317,342	68,285						385,627
Change In Control (4)	2,225,006	199,180	90,965		1,748,797	92,077	12,250	1,620,755	5,989,030

Note: The executives included in this table may perform services for more than one subsidiary of Dominion. Compensation for the individuals listed in the table and related footnotes reflect only the approximate portion related to their service for Virginia Power in the year presented.

(1) Grants made prior to 2006 are fully vested upon retirement. Grants made in 2006, 2007 and 2008 vest pro-rata upon retirement.
(2) Pursuant to a letter agreement dated February 28, 2003, Mr. Chewning will be entitled to a special payment of one times salary in exchange for a two-year non-compete agreement.
(3) Amounts in this column represent the value of the incremental benefit that the executives would receive for executive life insurance and retiree medical coverage. Executive life insurance for Messrs. Farrell, Heacock and Christian is only available upon a change in control. Messrs. Farrell and McGettrick are eligible for retiree medical if terminated without cause. Mr. Christian and Mr. Heacock are not age 55 and therefore are only eligible for retiree medical upon a change in control. Mr. Chewning is entitled to executive life insurance and retiree medical coverage upon any termination since he is retirement eligible and has completed 10 years of service. His annual executive life insurance premium is $39,160 and is payable until May 2010. Retiree medical benefits have been quantified using assumptions used for financial accounting purposes.
(4) The amounts indicated upon a change in control are the incremental amounts that each executive would receive over the amounts payable upon a retirement (Mr. Chewning) or termination without cause (Messrs. Farrell, McGettrick, Christian and Heacock).
(5) Because Mr. Chewning is eligible for retirement, the table above assumes he would retire in connection with any termination event, including death or disability. Mr. Chewning would not be entitled to the non-compete payment in the event of his death.

COMPENSATION COMMITTEE REPORT

The Company is a wholly-owned subsidiary of Dominion. Our Board is comprised of Messrs. Farrell, Chewning and Rogers. As executive officers of the Company, Messrs. Farrell and Chewning are not independent. Mr. Rogers is not considered to be independent because he is an officer of Dominion. Because our Board is not independent, we do not believe it is appropriate to have a separate compensation committee at our level. Instead, our Board depends on the advice and recommendations of Dominion s Compensation, Governance and Nominating Committee (CGN Committee) which is comprised of independent directors and which has retained the consulting firm of Pearl Meyer & Partners to advise them on compensation matters. Our Board approves all compensation paid to the Company s executive officers based on Dominion s CGN Committee recommendations. In preparation for the filing of this Annual Report on Form 10-K, we reviewed and discussed management s Compensation Discussion and Analysis and approved it for inclusion in this document.

Thomas F. Farrell, II

Thomas N. Chewning

Steven A. Rogers

February 24, 2009

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The table below sets forth as of February 16, 2009, the number of shares of Dominion common stock owned by the executive officers named on the Summary Compensation Table and directors.

Name of Beneficial Owner	Shares	Restricted Shares	Exercisable Stock Options	Total	Deferred Compensation
Thomas F. Farrell, II(1)	340,047	356,942	400,000	1,096,989	
Thomas N. Chewning	280,345	155,692	300,000	736,037	412
Steven A. Rogers	28,886	20,717		49,603	6,794
Mark F. McGettrick	70,451	83,322		153,773	12,457
David A. Christian	50,664	45,209		95,873	
David A. Heacock	35,357	19,351		54,708	
All directors and executive officers as a group (7 persons)(2)	820,581	700,982	700,000	2,221,563	19,663

(1) *Mr. Farrell disclaims ownership of 798 shares.*
(2) *All directors and executive officers as a group own less than one percent of the number of Dominion common shares outstanding as of February 16, 2009. No individual executive officer or director owns more than one percent of the shares outstanding.*

Item 13. Certain Relationships and Related Transactions

Related Party Transactions

In February 2007, our Board adopted the Related Party Guidelines also approved by Dominion s Board of Directors. These guidelines, which were most recently revised in October 2008, were adopted in order to recognize the process to be used in identifying potential conflicts of interest arising out of financial transactions, arrangements and relations between the Company and any related persons. Under our guidelines, a related person is a director, executive officer, director nominee, a beneficial owner of more than 5% of Dominion s common stock, or any immediate family member of one of the foregoing persons. A related party transaction is any financial transaction, arrangement or relationship (including any indebtedness or guarantee of indebtedness) or any series of similar transactions, arrangements or relationships in excess of $120,000 in which Dominion (and/or any of its consolidated subsidiaries) is a party and in which the related person has or will have a direct or indirect material interest.

In determining whether a direct or indirect interest is material, the significance of the information to investors in light of all circumstances is also considered. The importance of the interest to the person having the interest, the relationship of the parties to the transaction with each other and the amount involved are among the factors considered in determining the significance of the information to the investors.

Our guidelines set forth certain transactions which are not considered to be related party transactions including, among other things, compensation and expense reimbursement paid to directors and executive officers in the ordinary course of performing their duties; transactions with other companies where the

related party s only relationship is as an employee, if the aggregate amount involved does not exceed the greater of $1 million or 2% of that company s gross revenues; and charitable contributions which are less than the greater of $1 million or 2% of the charity s annual receipts. The full text of the guidelines can be found on Dominion s website at www.dom.com/about/governance/index.jsp.

We collect information about potential related party transactions (those in which a related party may have a material interest) in our annual questionnaires completed by directors and executive officers. The Corporate Secretary and the General Counsel review the potential related party transactions and assess whether any of the identified transactions constitute a related party transaction. Any identified related party transactions are then reported to Dominion s Compensation, Governance and Nominating (CGN) Committee. Dominion s CGN Committee reviews and considers relevant facts and circumstances and determines whether to ratify or approve the related party transactions identified. Dominion s CGN Committee may only approve or ratify related party transactions that are in, or are not inconsistent with, the best interests of Dominion and its shareholders and are in compliance with our Code of Ethics.

Since January 1, 2008 there have been no related party transactions as outlined herein involving the Company that were required either to be reported under the SEC related party rules or approved under the Company s policies.

Director Independence

We are a wholly-owned subsidiary of Dominion. The Board has determined that Thomas F. Farrell, II and Thomas N. Chewning, as executive officers of the Company and Steven A. Rogers, as an executive officer of Dominion, are not independent.

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Item 14. Principal Accountant Fees and Services

The following table presents fees paid to Deloitte & Touche LLP for the fiscal years ended December 31, 2008 and 2007.

Type of Fees (millions)	**2008**	2007
Audit fees	**$ 1.55**	$ 1.85
Audit-related		
Tax fees		
All other fees		
	$ 1.55	$ 1.85

Audit Fees. These amounts represent fees of Deloitte & Touche for the audit of our annual consolidated financial statements, the review of financial statements included in our quarterly Form 10-Q reports, and the services that an independent auditor would customarily provide in connection with subsidiary audits, statutory requirements, regulatory filings, and similar engagements for the fiscal year, such as comfort letters, attest services, consents, and assistance with review of documents filed with the SEC.

Audit-Related Fees. Audit-Related Fees consist of assurance and related services that are reasonably related to the performance of the audit or review of our consolidated financial statements or internal control over financial reporting. This category may include fees related to the performance of audits and attest services not required by statute or regulations, audits of our employee benefit plans, due diligence related to mergers, acquisitions, and investments, and accounting consultations about the application of generally accepted accounting principles to proposed transactions.

Our Board has adopted a pre-approval policy for our independent auditor s services and fees and has delegated to Dominion s Audit Committee the authority to pre-approve independent auditor services in accordance with the policy. In December 2008, Dominion s Audit Committee approved the independent auditor s schedule of services and estimated fees for 2009.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Certain documents are filed as part of this Form 10-K and are incorporated by reference and found on the pages noted.

1. Financial Statements

See Index on page 29.

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

2. Exhibits

3.1	Restated Articles of Incorporation, as in effect on October 28, 2003 (Exhibit 3.1, Form 10-Q for the quarter ended September 30, 2003, File No. 1-2255, incorporated by reference).
3.2	Bylaws, as amended, as in effect on April 28, 2000 (Exhibit 3, Form 10-Q for the period ended March 31, 2000, File No. 1-2255, incorporated by reference).
4	Virginia Electric and Power Company agrees to furnish to the Securities and Exchange 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 its total consolidated assets.
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); and 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).
4.3	Subordinated Note Indenture, dated as of August 1, 1995 between Virginia Electric and Power Company and The Bank of New York (as successor trustee to 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).
4.4	Form of Senior Indenture, dated as of June 1, 1998, between Virginia Electric and Power Company and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by the First Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 4, 1999, File No. 1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K filed October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K filed March 26, 2001, File No. 1-2255, incorporated by reference); Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K filed March 26, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 29, 2002, File No. 1-2255, incorporated by reference); Seventh Supplemental Indenture (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, 2003, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 11, 2003, File No. 1-2255, incorporated by reference); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Thirteenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Fourteenth

Supplemental Indenture (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255, incorporated by reference); Form of Fifteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255, incorporated by reference); Form of Sixteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 30, 2007, File No. 1-2255, incorporated by reference); Form of Seventeenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255, incorporated by reference); Form of Eighteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed April 15, 2008, File No. 1-2255, incorporated by reference); Nineteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 5, 2008, File No. 1-2255, incorporated by reference).

4.5	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	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).
10.2	Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-2255, incorporated by reference).
10.3	$3.0 billion, Five-Year Credit Agreement dated February 28, 2006 among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Citibank, N.A., as Syndication Agent and Barclays Bank PLC, Bank of Nova Scotia and Wachovia Bank, National Association, as Co-Documentation Agents and other lenders named therein (Exhibit 10.1, Form 8-K filed March 3, 2006, File No. 1-2255, incorporated by reference).

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10.4*	Dominion Resources, Inc. Executive Supplemental Retirement Plan, as amended and restated effective December 17, 2004 (Exhibit 10.5, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.5*	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), as amended June 20, 2007 (Exhibit 10.5, Form 10-K for the fiscal year ended December 31, 2007, File No. 1-2255, incorporated by reference).
10.6*	Dominion Resources, Inc. 2005 Incentive Compensation Plan (Exhibit 10, Form 8-K filed March 3, 2005, File No. 1-8489, incorporated by reference), as amended April 27, 2007 (Exhibit 10.6, Form 10-K for the fiscal year ended December 31, 2007, File No. 1-2255, incorporated by reference).
10.7*	Form of Restricted Stock Grant under 2006 Long-Term Compensation Program approved March 31, 2006 (Exhibit 10.1, Form 8-K filed April 4, 2006, File No. 1-8489, incorporated by reference).
10.8*	Form of Performance Grant under 2006 Long-Term Compensation Program approved March 31, 2006, as amended and restated January 24, 2008 (Exhibit 10.1, Form 8-K filed January 30, 2008, File No. 1-8489, incorporated by reference).
10.9*	Form of Restricted Stock Grant under 2007 Long-Term Compensation Program approved March 30, 2007 (Exhibit 10.1, Form 8-K filed April 5, 2007, File No. 1-8489, incorporated by reference).
10.10*	Form of Performance Grant under 2007 Long-Term Compensation Program approved March 30, 2007 (Exhibit 10.2, Form 8-K filed April 5, 2007, File No. 1-8489, incorporated by reference).
10.11*	Form of Restricted Stock Award Agreement under 2008 Long-Term Compensation Program approved March 27, 2008 (Exhibit 10.1, Form 8-K filed April 2, 2008, File No. 1-8489, incorporated by reference).
10.12*	2008 Performance Grant Plan under 2008 Long-Term Compensation Program approved March 27, 2008 (Exhibit 10.2, Form 8-K filed April 2, 2008, File No. 1-8489, incorporated by reference).
10.13*	Form of Restricted Stock Award Agreement under 2009 Long-Term Compensation Program approved January 26, 2009 (Exhibit 10.2, Form 8-K filed January 29, 2009, File No. 1-8489, incorporated by reference).
10.14*	2009 Performance Grant Plan under 2009 Long-Term Compensation Program approved January 26, 2009 (Exhibit 10.1, Form 8-K filed January 29, 2009, File No. 1-8489, incorporated by reference).
10.15*	Form of Employment Continuity Agreement for certain officers of the Company, amended and restated July 15, 2003 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003, File No. 1-2255, incorporated by reference), as amended March 31, 2006 (Form 8-K filed April 4, 2006, File No. 1-8489, incorporated by reference).
10.16*	Dominion Resources, Inc. Retirement Benefit Funding Plan, effective June 29, 1990 as amended and restated September 1, 1996 (Exhibit 10(iii), Form 10-Q for the quarter ended June 30, 1997, File No. 1-8489, incorporated by reference).
10.17*	Dominion Resources, Inc. Retirement Benefit Restoration Plan, as amended and restated effective December 17, 2004 (Exhibit 10.6, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.18*	Dominion Resources, Inc. Executives Deferred Compensation Plan, amended and restated effective December 17, 2004 (Exhibit 10.7, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.19*	Dominion Resources, Inc. New Executive Supplemental Retirement Plan, effective January 1, 2005 (Exhibit 10.8, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference), amended January 19, 2006 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2005, File No. 1-8489, incorporated by reference), amended December 1, 2006, and further amended January 1, 2007 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2006, File No. 1-8489, incorporated by reference), as amended and restated effective January 1, 2009 (Exhibit 10.1, Form 10-Q for the quarter ended September 30, 2008, incorporated by reference).
10.20*	Dominion Resources, Inc. New Retirement Benefit Restoration Plan, effective January 1, 2005 (Exhibit 10.9, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference), amended January 1, 2007 (Exhibit 10.18, Form 10-K for the fiscal year ended December 31, 2006, File No. 1-8489, incorporated by reference), as amended and restated effective January 1, 2009 (Exhibit 10.2, Form 10-Q for the quarter ended September 30, 2008, incorporated by reference), as amended and restated effective January 1, 2009 (filed herewith).
10.21*	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. 1-2255, incorporated by reference).

10.22*	Dominion Resources, Inc. Security Option Plan, effective January 1, 2003, amended December 31, 2004 and restated effective January 1, 2005 (Exhibit 10.13, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.23*	Form of Advancement of Expenses for certain directors and officers of Dominion, approved by the Dominion Board of Directors on October 24, 2008 (Exhibit 10.3, Form 10-Q for the quarter ended September 30, 2008, incorporated by reference).
12.1	Ratio of earnings to fixed charges (filed herewith).
12.2	Ratio of earnings to fixed charges and dividends (filed herewith).
21	Subsidiaries of the Registrant (filed herewith).
23	Consent of Deloitte & Touche LLP (filed herewith).
31.1	Certification by Registrant s Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification by Registrant s Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32	Certification to the Securities and Exchange Commission by Registrant s Chief Executive Officer and Chief Financial Officer, as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
99	Participants in Executive Compensation Surveys (filed herewith).

* *Indicates management contract or compensatory plan or arrangement.*

Table of Contents

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/ THOMAS F. FARRELL, II
(Thomas F. Farrell, II,

Chairman of the Board of Directors

and Chief Executive Officer)

Date: February 26, 2009

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 26th day of February, 2009.

Signature	Title
/s/ THOMAS F. FARRELL, II **Thomas F. Farrell, II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ THOMAS N. CHEWNING **Thomas N. Chewning**	Director, Executive Vice President and Chief Financial Officer
/s/ THOMAS P. WOHLFARTH **Thomas P. Wohlfarth**	Senior Vice President and Chief Accounting Officer
/s/ STEVEN A. ROGERS **Steven A. Rogers**	Director