Dominion®

North Anna 3 Combined License Application

Part 1: General and Administrative Information

Revision 0
November 2007

PART 1: GENERAL AND ADMINISTRATIVE INFORMATION

1. Introduction

Pursuant to Sections 103 and 185(b) of the Atomic Energy Act, and 10 CFR 52, Subpart C, Virginia Electric and Power Company, doing business as Dominion Virginia Power (DVP or Dominion), and Old Dominion Electric Cooperative (ODEC) hereby apply to the U.S. Nuclear Regulatory Commission (NRC) for a combined license (COL) to construct and operate an ESBWR at the North Anna Power Station (NAPS). DVP and ODEC also apply for such other licenses as would be required to possess and use source, special nuclear and by-product material in connection with the operation of the ESBWR. The ESBWR will be designated and hereinafter referred to as Unit 3.

NAPS is located in Louisa County, Virginia, approximately 40 miles north northwest of Richmond. There are two existing nuclear reactors in operation at NAPS, as well as an Independent Spent Fuel Storage Installation (ISFSI). Unit 3 will be located adjacent to and generally west of the existing units.

DVP and ODEC currently own NAPS, including the existing nuclear units and ISFSI at that site, as tenants in common, with respective undivided ownership interests of 88.4 and 11.6 percent. DVP is the licensed operator of the existing facilities, with control of the NAPS site and existing facilities and authority to act as ODEC's agent. DVP and ODEC will own Unit 3 with the same undivided ownership interests and DVP will construct and operate Unit 3.

The ESBWR is a 4,500 MWt reactor that uses natural circulation for normal operation and has passive safety features. General Electric Company (GE, now GE-Hitachi Nuclear Energy Americas, LLC (GEH)) submitted an application for final design approval and standard design certification for the ESBWR on August 24, 2004, which the NRC is currently reviewing under docket number 52-010. It is anticipated that the design certification of the ESBWR will be issued in June 2010. This COL application references and incorporates Revision 4 of the Design Control Document (DCD) currently under review in the design certification proceeding.

This COL application also references Revision 9 of the Early Site Permit (ESP) application for the North Anna ESP site, and will reference that ESP upon issuance. The ESP application evaluated the suitability of NAPS for two additional units bounded by a plant parameter envelope (PPE). The PPE was selected to bound the design characteristics of a number of reactor designs, including the ESBWR. This COL application incorporates the information from the ESP Site Safety Analysis Report (SSAR) and Environmental Report that addressed siting and environmental issues in the ESP proceeding.

2. Information Required by 10 CFR 50.33

2(a)-(d) Corporate Information

NRC regulations at 10 CFR 50.33(a)–(d) require that an application contain certain corporate information about the applicants. Information about DVP and ODEC respectively is provided below.

Corporate Information for Virginia Electric and Power Company

Name of Applicant	Virginia Electric and Power Company (Dominion or DVP)
Address	120 Tredegar Street Richmond, VA 23219-3932
State of Incorporation	Virginia
Principal Business Location	120 Tredegar Street Richmond, VA 23219-3932

Description of Business

DVP was incorporated in 1909 as a Virginia public service corporation. DVP is a regulated public utility engaged in the power generation and electric service delivery business within a 30,000 square-mile service area in Virginia and northeastern North Carolina. DVP supplies energy at retail to approximately 2.3 million customer accounts including governmental agencies, and to wholesale customers such as rural electric cooperatives and municipalities.

Names, addresses, and citizenship of DVP directors and principal officers

Name	Title	Address	Citizenship
Thomas F. Farrell, II	Chairman and Chief Executive Officer	100 Tredegar St. Richmond, VA 23219-3932	USA
Thomas N. Chewning	Director, Executive Vice President, and Chief Financial Officer	100 Tredegar St. Richmond, VA 23219-3932	USA
Steven A. Rogers	Director	100 Tredegar St. Richmond, VA 23219-3932	USA
David A. Christian	President and Chief Nuclear Officer	5000 Dominion Boulevard Glen Allen, VA 23060	USA
Jay L. Johnson	President and Chief Operating Officer – Dominion Virginia Power	120 Tredegar St. Richmond, VA 23219-3932	USA
Mark F. McGettrick	President and Chief Operating Officer – Generation	120 Tredegar St. Richmond, VA 23219-3932	USA

Names, addresses, and citizenship of DVP directors and principal officers

Name	Title	Address	Citizenship
M. Stuart Bolton Jr.	Senior Vice President – Regulatory Accounting	100 Tredegar St. Richmond, VA 23219-3932	USA
Mary C. Doswell	Senior Vice President – Regulation and Integrated Planning	100 Tredegar St. Richmond, VA 23219-3932	USA
David A. Heacock	Senior Vice President – Dominion Virginia Power	5000 Dominion Boulevard Glen Allen, VA 23060	USA
G. Scott Hetzer	Senior Vice President and Treasurer	100 Tredegar St. Richmond, VA 23219-3932	USA
E. Paul Hilton	Senior Vice President – Regulation	120 Tredegar St. Richmond, VA 23219-3932	USA
Craig S. Ivey	Senior Vice President – Transmission & Distribution	120 Tredegar St. Richmond, VA 23219-3932	USA
James K. Martin	Senior Vice President – Business Development & Generation Construction	5000 Dominion Boulevard Glen Allen, VA 23060	USA
William R. Matthews	Senior Vice President – Nuclear Operations	5000 Dominion Boulevard Glen Allen, VA 23060	USA
Margaret E. McDermid	Senior Vice President and Chief Information Officer	100 Tredegar St. Richmond, VA 23219-3932	USA
J. David Rives	Senior Vice President - Fossil & Hydro	5000 Dominion Boulevard Glen Allen, VA 23060	USA
James F. Stutts	Senior Vice President and General Counsel	100 Tredegar St. Richmond, VA 23219-3932	USA
Thomas P. Wohlfarth	Senior Vice President and Chief Accounting Officer	100 Tredegar St. Richmond, VA 23219-3932	USA
Fred G. Wood, III	Senior Vice President – Financial Management – Generation	120 Tredegar St. Richmond, VA 23219-3932	USA
Kenneth D. Barker	Vice President – Planning	120 Tredegar St. Richmond, VA 23219-3932	USA
Thomas R. Bean	Vice President – Financial Management – Dominion Virginia Power	120 Tredegar St. Richmond, VA 23219-3932	USA
Gerald T. Bischof	Vice President – Nuclear Engineering	5000 Dominion Boulevard, 2SE Glen Allen, VA 23060	USA

Names, addresses, and citizenship of DVP directors and principal officers

Name	Title	Address	Citizenship
P. Rodney Blevins	Vice President – Distribution	120 Tredegar St. Richmond, VA 23219-3932	USA
Malcolm G. Deacon, Jr.	Vice President – Fossil & Hydro Technical Services	5000 Dominion Boulevard Glen Allen, VA 23060	USA
Pamela F. Faggert	Vice President – Chief Environmental Officer	5000 Dominion Boulevard Glen Allen, VA 23060	USA
Eugene S. Grecheck	Vice President – Nuclear Development	5000 Dominion Boulevard Glen Allen, VA 23060	USA
Leslie N. Hartz	Vice President – Nuclear Support Services	5000 Dominion Boulevard Glen Allen, VA 23060	USA
David W. Green	Vice President – Customer Service	120 Tredegar St. Richmond, VA 23219-3932	USA
C. Douglas Holley	Vice President – Fossil & Hydro System Operation	5000 Dominion Boulevard Glen Allen, VA 23060	USA
Karen E. Hunter	Vice President – Tax	120 Tredegar St. Richmond, VA 23219-3932	USA
Robert B. McKinley	Vice President – Generation Construction	701 East Cary Street, 21st Floor Richmond, VA 23219	USA
Ashwini Sawhney	Vice President - Accounting	701 East Cary Street 17th Floor Richmond, VA 23219	USA
Christine M. Schwab	Vice President – Business Development	100 Tredegar St. Richmond, VA 23219-3932	USA
David G. Shuford	Vice President – State Regulation	120 Tredegar St. Richmond, VA 23219-3932	USA
John D. Smatlak	Vice President –Transmission	120 Tredegar St. Richmond, VA 23219-3932	USA
Shannon L. Venable	Vice President – Integrated Resource Planning	120 Tredegar St. Richmond, VA 23219-3932	USA
Patricia A. Wilkerson	Vice President and Corporate Secretary	100 Tredegar St. Richmond, VA 23219-3932	USA
Donald E. Jernigan	Site Vice President – Surry	Surry Power Station 5570 Hog Island Road Surry, VA 23883	USA
Daniel G. Stoddard	Site Vice President – North Anna	1022 Haley Drive Mineral, VA 23117	USA

No Foreign Ownership, Control, or Influence

DVP is not owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government.

Corporate Information for Old Dominion Electric Cooperative

Name of Applicant	Old Dominion Electric Cooperative (ODEC)
Address	4201 Dominion Boulevard Glen Allen, VA 23060
State of Incorporation	Virginia
Principal Business Location	4201 Dominion Boulevard Glen Allen, VA 23060

Description of Business

ODEC, which was incorporated under the laws of the Commonwealth of Virginia in 1948, is a not-for-profit wholesale power supply cooperative engaged in the business of providing wholesale electric service to twelve member distribution cooperatives (Members), which in turn are engaged in the retail sale of power to member consumers located in 70 counties throughout Virginia, Delaware, Maryland and West Virginia. ODEC's board of directors is made up of two directors from each of its Members.

Names, addresses, and citizenship of ODEC directors and officers

Name	Title	Address	Citizenship
James M. Reynolds	Chairman	Community Electric Cooperative 52 West Windsor Blvd P.O. Box 267 Windsor, VA 23487-0267	USA
Frederick L. Hubbard	Vice Chairman	Choptank Electric Cooperative 24820 Meeting House Rd P.O. Box 430 Denton, MD 21629	USA
Gregory W. White	Secretary/Treasurer	Northern Neck Electric Cooperative 85 St. Johns Street P.O. Box 288 Warsaw, VA 22572-0288	USA
J. William Andrew	Director	Delaware Electric Cooperative 14198 Sussex Highway P.O. Box 600 Greenwood, DE 19950-0600	USA

Names, addresses, and citizenship of ODEC directors and officers

Name	Title	Address	Citizenship
M. John Bowman	Director	Mecklenburg Electric Cooperative 11633 Highway 92 West P.O. Box 2451 Chase City, VA 23924-2451	USA
M Dale Bradshaw	Director	Prince George Electric Cooperative 7103 General Mahone Highway P.O. Box 168 Waverly, VA 23890-0168	USA
Vernon N. Brinkley	Director	A&N Electric Cooperative 21275 Cooperative Way P.O. Box 290 Tasley, VA 23441-0290	USA
Calvin P. Carter	Director	6262 Bedford Highway Lynch Station, VA 24571	USA
Glenn F. Chappell	Director	17420 Old Stage Road Carson, VA 23830	USA
Jeffrey S. Edwards	Director	Southside Electric Cooperative 2000 West Virginia Ave P.O. Box 7 Crewe, VA 23930-0007	USA
Kent D. Farmer	Director	Rappahannock Electric Cooperative 247 Industrial Court (zip code: 22408) P.O. Box 7388 Fredericksburg, VA 22404-7388	USA
Stanley C. Feuerberg	Director	Northern Virginia Electric Cooperative 10323 Lomond Drive (zip code: 20109) P.O. Box 2710 Manassas, VA 20108-0875	USA
William C. Frazier	Director	17225 Taylor’s Creek Road Montpelier, VA 23192	USA

Names, addresses, and citizenship of ODEC directors and officers

Name	Title	Address	Citizenship
Fred C. Garber	Director	7484 South Middle Road Mount Jackson, VA 22842	USA
Hunter R. Greenlaw Jr.	Director	142 Albion Lane (zip code: 22405) P.O. Box 149 Fredericksburg, VA 22404	USA
Bruce A. Henry	Director	12134 Beach Highway Greenwood, DE 19950	USA
Wade C. House	Director	14521 Vint Hill Road Nokesville, VA 20181	USA
David J. Jones	Director	6874 Highway One Bracey, VA 23919	USA
Bruce M. King	Director	BARC Electric Cooperative 84 High Street P.O. Box 264 Millboro, VA 24460-0264	USA
William M. Leech, Jr.	Director	518 Bluegrass Trail Lexington, VA 24450	USA
Paul E. Owen	Director	106 Chrisfield Circle Smithfield, VA 23430	USA
Myron D. Rummel	Director	Shenandoah Valley Electric Cooperative 147 Dinkel Avenue – Highway 257 P.O. Box 236 Mt. Crawford, VA 22841-0236	USA
Philip B. Tankard	Director	8410 Grapeland Farm Rd P.O. Box 69 Franktown, VA 23354	USA
Carl R. Widdowson	Director	29754 Widdowson Lane Princess Anne, MD 21853	USA
Elissa M. Ecker	Vice President of Human Resources	4201 Dominion Blvd Glen Allen, VA 23060	USA
Lisa M. Johnson	Senior Vice President of Power Supply	4201 Dominion Blvd Glen Allen, VA 23060	USA
Robert L. Kees	Senior Vice President and CFO	4201 Dominion Blvd Glen Allen, VA 23060	USA

Names, addresses, and citizenship of ODEC directors and officers

Name	Title	Address	Citizenship
John C. Lee, Jr.	Vice President of Member and External Relations	4201 Dominion Blvd Glen Allen, VA 23060	USA
Jackson E. Reasor	President and CEO	4201 Dominion Blvd Glen Allen, VA 23060	USA

No Foreign Ownership, Control, or Influence

ODEC is not owned, controlled or dominated by an alien, a foreign corporation or a foreign government.

Agents and Representatives

DVP is submitting this application on its own behalf and on behalf of ODEC. Otherwise, neither DVP nor ODEC is acting as agent or representative of any other person in filing this application.

(e) Class of License, Use of Facility, Period of Time for which the License is Sought, and Other Licenses Issued or Applied for in Connection with the Proposed Facility

This application seeks a class 103 license for Unit 3, which will be used to generate electricity for commercial purposes. Pursuant to 10 C.F.R. § 52.104, DVP and ODEC request a combined license with a term of 40 years, commencing from the date that the Commission makes the finding that the acceptance criteria in the license are met under § 52.103(g) or allowing operation during an interim period under 52.103(c).

Pursuant to 10 C.F.R. § 52.8, this application also seeks licenses, which would be incorporated into the COL, to receive, possess and use source, special nuclear by-product material in connection with the operation of Unit 3. Specifically, as the proposed operator of Unit 3, DVP seeks authority: 1) to receive, possess, and use at any time special nuclear material as reactor fuel; 2) to receive, possess and use at any time any by-product, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required; 3) to receive, possess and use in amounts as required any by-product, source or special nuclear material without restriction to chemical or physical form for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components; and 4) to possess but not separate such by-product and special nuclear material as may be produced by the operation of the facility.

(f) Financial Qualifications

(f)(1) Construction Funds

DVP is one of the nation's 10 largest investor-owned electric utilities. It delivers power to more than 2.3 million homes and businesses in Virginia and North Carolina. The Virginia service area comprises about 65 percent of Virginia's total land area, but accounts for over 80 percent of its population. It owns and operates 15,552 megawatts of generating capacity, controls an additional 2,076 megawatts from non-utility generators, and had operating revenues of approximately $5,603 million for the year ended December 31, 2006. DVP's mortgage bond ratings are A- from Standard and Poor's and A3 from Moody's with senior unsecured ratings of BBB from Standard and Poor's and Baa1 from Moody's.

DVP is a wholly owned subsidiary of Dominion Resources, Inc. (DRI), which is one of the nation's leading energy companies with approximately $49 billion in assets and operating revenue of approximately $16,500 million through the year ended December 31, 2006. DRI has recently completed the divestiture of its non-Appalachian E&P properties which decreased its asset base to approximately $39 billion in assets. Its current asset base includes about 26,500 megawatts of electric generation, 1.0 trillion cubic feet equivalent of proved natural gas and oil reserves and nearly 7,800 miles of natural gas transmission pipeline, and the nation's largest underground natural gas storage system with about 960 billion cubic feet of storage capacity.

ODEC's customer base comprises the twelve Members which own ODEC. Through the Members, ODEC served more than 535,000 retail electric consumers (meters) representing a total population of approximately 1.3 million people in 2006. Power is provided to each Member pursuant to a long-term, all-requirements wholesale power contract (WPC) that obligates ODEC to sell and deliver to the Member, and which obligates the Member to purchase and receive from ODEC, all power that the Member requires for the operation of its systems, with limited exceptions, to the extent that ODEC has the power and facilities available to do so. Each Member is required to pay ODEC monthly for the power furnished to it under the WPC in accordance with ODEC's formulary rate. The formulary rate, which has been filed with and accepted by the Federal Energy Regulatory Commission (FERC), is designed to recover ODEC's total cost of service and create a firm equity base.

As of September 30, 2007, ODEC had total assets of approximately $1,712 million and patronage capital (equity) of approximately $304 million. Total revenue for the year ended December 31, 2006, and the nine months ended September 30, 2007 was approximately $818 million and $718 million, respectively.

To facilitate its access to funding, ODEC maintains high quality, investment grade credit ratings. ODEC's current bond ratings as issued by Standard and Poor's, Moody's and Fitch are A, A3 and A, respectively. All three ratings carry a "stable" outlook.

Over the past 15 years ODEC has successfully issued taxable and tax-exempt bonds through the capital markets to finance construction of the Clover Power Station, and the Rock Springs, Louisa and Marsh Run combustion turbine facilities.

Estimate of Construction Costs

For purposes of demonstrating financial qualifications, a conservative ESBWR construction cost estimate is provided below. This estimate is based on a number of studies that have been conducted by governmental agencies, universities and other entities and includes a significant contingency to account for uncertainty.

The construction cost estimate is expressed in terms of "overnight capital cost," which is a term commonly used in describing the cost of large capital projects. This overnight capital cost includes the engineering, procurement and construction costs for the ESBWR plant, owner's costs, and contingencies, but excludes interest and escalation during the construction. Owner's costs include site work and preparation, cooling water intake structures and cooling towers, import duties on components, insurance, spare parts, transmission interconnection, development costs, project management costs, owner's engineering, state and local permitting, legal fees, and staffing-related training.

In 2003, the Massachusetts Institute of Technology published an interdisciplinary study entitled The Future of Nuclear Power.[1] The MIT report provided a base-case estimate of $2,000/kWe (in 2002 dollars) for the overnight capital cost of new nuclear units. This estimate is based in part on two completed Advanced Boiling Water Reactors (ABWRs) at the Kashiwazaki-Kariwa Nuclear (KKN) Power Station, with reported construction costs of $1,800 to $2,000/kWe.[2] While a specific estimate for an ESBWR is not provided, the MIT report indicates that the ESBWR is a simplified design the overnight cost of which would be lower than an ABWR.[3]

In 2004, the U.S. Department of Energy's Energy Information Agency examined nuclear power plant costs as part of its 2004 Annual Energy Outlook (AEO).[4] The 2004 AEO based its estimate on two Generation III light-water reactors in operation (presumably the two KKN ABWRs) and another four under construction in Asia. It used as its starting point the $2,083 per kWe realized cost (inclusive of all contingencies) for the two completed reactors. It then projected that the realized cost, inclusive of contingencies, for the sixth unit would be $1,928 per kWe when completed.

In 2005, the Nuclear Energy Agency (NEA) of the Organization for Economic Cooperation and Development provided an update on Projected Costs of Generating Electricity.[5] The NEA report examined a reference set of thirteen plants and reported overnight construction costs generally ranging between $1,000 to $2,000 per kWe, with one unit at $2,100 per kWe and another at $2,500 per kWe.

In 2007, the Keystone Center published a report entitled Nuclear Power Joint Fact-Finding.[6] The Keystone Center examined the overnight cost of eight recently completed reactors, with overnight costs ranging from $1,790/kWe to $2,818/kWe in 2002 dollars. The average overnight cost for these plants was $2,150/kWe in 2002 dollars, which the Keystone Report escalated to $2,950/kWe in 2007 using a 3.3 percent real escalation rate. The Keystone report then considered several scenarios of interest and escalation over a construction period to develop the following range of final construction costs:

- $3,600/kWe (0% real escalation, 5-year construction period)

1. Massachusetts Institute of Technology (MIT), "The Future of Nuclear Power, An Interdisciplinary MIT Study," 2003. (web.mit.edu/nuclearpower/pdf/nuclearpower-full.pdf).
2. Id., App. 5 at 141-142.
3. Id. at 138.
4. Energy Information Administration (EIA), "Annual Energy Outlook 2004," DOE/EIA-0383(2004). (www.econstats.com/EIA/AEO2004.pdf).
5. Nuclear Energy Agency, Organization for Economic Co-operation and Development (OECD), and International Energy Agency, "Projected Costs of Generating Electricity," 2005 Update. (www.oecdbookshop.org).
6. The Keystone Center, Nuclear Power Joint Fact-Finding (June 2007). (www.keystone.org/spp/documents/FinalReport_NJFF6_12_2007(1).pdf).

- $4,000/kWe (3.3% real escalation, 6-year construction period).
- $4,200/kWe (3.3% real escalation, 7-year construction period).

Similarly, a recent presentation by the Chief Financial Officer of FPL Group estimates a total overnight cost of $2,400–$3,500 per kWe.[7] When escalation and interest during the construction period is considered, the overnight costs translate to final construction costs of between $4,000–$5,500 per kWe. Another recent commentator has also suggested capital cost in the $3,200–$4,000 range per kWe (2007 dollars) in light of an escalating plant cost index.[8]

Based on the studies described above, for purposes of demonstrating financial qualifications, a reasonable estimate of the overnight cost of a new nuclear unit is approximately $3,000/kWe in 2007 dollars. For conservatism, a further contingency is added as discussed below.

There are uncertainties in estimating the cost of building a new nuclear unit. First, many studies rely on recent nuclear construction projects outside the United States. Therefore, the Unit 3 cost contingency considers the potential shortage of skilled construction labor in the United States.[9] Second, the Unit 3 cost contingency considers the cost escalation that could result from the increasing global demand for commodities.

There are also factors that militate against higher costs for Unit 3. First, site investigation and site suitability costs have already been incurred during the North Anna ESP proceeding. Similarly, the costs of preparing and obtaining the COL, and GEH's cost of obtaining design certification and completing the detailed generic design for the ESBWR will be incurred prior to COL issuance and will be funded on a cost-sharing basis under Cooperative Agreements with the U.S. Department of Energy. Second, DVP has already ordered certain long-lead components such as the large forgings (e.g. reactor vessel) and other nuclear and turbine island parts for delivery to preserve its ability to meet a 2015 commercial operations date. As a result, DVP will avoid any supply chain constraints in the delivery of these forgings and components, and is protected from escalating prices resulting from the global nuclear expansion. Third, the transmission upgrade requirements needed to accommodate a third unit at North Anna are minimal – on the order of $40 to $50 million. These factors could reduce the going-forward overnight cost by as much as $500/kWe.

While these factors may offset the uncertainties in the expected cost of Unit 3, DVP has nevertheless added a contingency of over 30 percent ($1,000/kWe) to the $3,000/kWe overnight cost estimate for a new nuclear unit such as Unit 3 for purposes of conservatively demonstrating

7. M. Dewhurst, "Financial Perspectives on Nuclear Power in a Consolidating Electric Power Industry" (Feb. 8, 2007), Presentation at Platts Nuclear Energy Conference (February 2007).
8. J. Harding, "Costs and Prospects for New Nuclear Reactors" (Feb. 2007), Presentation to NW Power Council. (www.nwcouncil.org/news/2007_02/p1.pdf).
9. As indicated in the Keystone Report, when overnight costs are escalated to determine costs incurred over the construction period, an added year of construction would add on the order of $200/kW to the realized construction costs. See Keystone Report at note 34.

financial qualifications. A breakdown of the construction costs under these assumptions is provided below:

Overnight Construction Cost

Power Block (Nuclear Island and Turbine Island)	$2,000 to 2,500/kWe
Owners' Cost (Balance of Plant, Circulating Water Cooling System, Site Preparation, Transmission, and Contingency)	$1,000 to 1,500/kWe.
Nuclear fuel inventory cost for first core	$320 million
Total estimated cost	$3,000 to 4,000/kWe

DVP's Source of Construction Funds

DVP plans to finance the cost to construct Unit 3 through a combination of debt and equity. The relative amount of debt and equity may depend on the availability of federal loan guarantees under the provisions of the Energy Policy Act of 2005. If loan guarantees are available on satisfactory terms, DVP may limit its required equity to 20 percent of project cost by issuing federally guaranteed debt for the remaining 80 percent. If these loan guarantees are not available on satisfactory terms, an equity contribution of up to 50 percent could be required to maintain investment grade ratings for the debt. In either case, DVP has sufficient capacity from a combination of internal and external funds for the equity and debt. The traditional capital markets will serve as the sources for the financing. The provisions of the Virginia Code that will help DVP obtain financing from the capital markets for Unit 3 are described below.

Under Virginia Code § 56-585.1.A.6, a utility that constructs a nuclear generation facility has the right to recover the costs of the facility through a rate adjustment clause. This rate recovery includes projected construction work in progress (CWIP), and associated allowance for funds used during construction (AFUDC). Allowable costs include planning, development and construction costs, life-cycle costs, and costs of infrastructure associated therewith. Projected CWIP and AFUDC can be recovered prior to the date the facility begins commercial operation. As an incentive to undertake a nuclear generation facility, the statute allows an enhanced rate of return on common equity of 200 basis points above the utility's general rate of return on common equity. This enhanced rate of return on common equity is applied to CWIP and the calculation of AFUDC during the facility construction phase. It is also applied to the nuclear facility from the date of the commencement of commercial operation and continuing for a period of 12 to 25 years, as the Virginia State Corporation Commission (VSCC) shall determine. After this period, the general rate of return is applied to the facility for the remainder of its service life.

ODEC's Source of Construction Funds

ODEC obtains long-term funding primarily by the issuance of taxable and tax-exempt bonds through the capital markets. As of September 30, 2007, ODEC had approximately $900 million of bonds outstanding under its Indenture of Mortgage and Deed of Trust (the “Indenture”). The need for additional long-term funds would likely be accommodated by the issuance of additional bonds under the Indenture. Additionally, ODEC maintains various liquidity facilities to cover short- and medium-term funding needs. As of September 30, 2007, ODEC had $280 million in such facilities, under which $0 was outstanding. Per the terms of the Wholesale Power Contract (WPC) and in accordance with its FERC formulary rate, ODEC collects from its Members all its costs, including payments of principal and premium, if any, and interest on all indebtedness. Internally available cash, provided primarily by undistributed earnings (patronage capital) may also be utilized to fund a portion of future construction costs and other capital expenditures.

As mentioned previously, ODEC’s ability to access funding is facilitated by its maintenance of high quality, investment grade credit ratings. ODEC’s current bond ratings as issued by Standard and Poor’s, Moody’s and Fitch are A, A3 and A, respectively. All three ratings carry a “stable” outlook.

Financial Statements

DVP files its financial statements with the Securities and Exchange Commission (SEC). (investors.dom.com/phoenix.zhtml?c=110481&p=irol-sec).

DVP’s most recent annual financial statement (SEC Form 10-K for the year ended December 31, 2006) is provided as Attachment A hereto, and DVP’s most recent quarterly financial statement SEC Form 10-Q for the quarterly period ended September 30, 2007 is provided as Attachment B.

ODEC likewise files its financial statements with the SEC. ODEC’s SEC Form 10-K for the year ended December 31, 2006, is provided as Attachment C hereto, and ODEC’s most recent quarterly financial statement SEC Form 10-Q for the quarterly period ended September 30, 2007 is provided as Attachment D.

These financial statements confirm the financial strength of DVP and ODEC that, when coupled with the financial stability associated with a regulated electric utility, reasonably assure the funding required to construct Unit 3.

(f)(2) Operating Funds

DVP and ODEC are both electric utilities as defined in 10 CFR 50.2. DVP generates and distributes electricity and recovers the cost of this electricity through cost-of-service based rates established by the VSCC, the North Carolina Utilities Commission (NCUC), and FERC. ODEC is a wholesale electric cooperative which generates and purchases electricity, and in turn, distributes such electricity to its Members. ODEC recovers the cost of this electricity through cost-of-service based rates established by ODEC pursuant to its formulary rate which has been accepted by FERC.

(g) Radiological Emergency Response Plans

Information on the state and local radiological emergency response plans required by 10 CFR 50.33(g) is provided in Chapter 13 of the Final Safety Analysis Report.

(h) [Not applicable to an application for a combined license]

(i) Listing of Regulatory Agencies Having Jurisdiction and News Publications

FERC, the VSCC and the NCUC are the principal regulators of DVP's electric operations in Virginia and North Carolina. FERC regulates a number of ODEC activities, including the rates and charges made, demanded, or received by ODEC for the transmission and wholesale sale of power in interstate commerce. ODEC is also subject to regulations by the VSCC on the siting of ODEC's utility facilities and its acquisition and disposition of its utility assets located in Virginia.

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

Mr. Joel H. Peck, Clerk
c/o Document Control Center
Virginia State Corporation Commission
1300 East Main Street
Tyler Building – First Floor
Richmond, VA 23218

Ms. Renné Vance, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699

The area news publications and their associated addresses are provided below.

Richmond Times-Dispatch
P.O. Box 85333
Richmond, VA 23293

Central Virginian
P.O. Box 464
Louisa, VA 23093

Daily Progress
P.O. Box 9030
Charlottesville, VA 22906

Orange County Review
P.O. Box 589
Orange, VA 22960

Free Lance-Star
616 Amelia Street
Fredericksburg, VA 22401

(j) Restricted Data Agreement

This application does not contain restricted data or other national defense information, nor is it expected that subsequent amendments to the license application will contain such information. However, pursuant to 10 CFR 54.17(g) and 10 CFR 50.37, DVP and ODEC, as a part of the application for a combined construction and operation license, hereby agree that they will not permit any individual to have access to or any facility to possess restricted data or classified national security information until the individual and/or facility has been approved for such access under the provisions of 10 CFR Parts 25 and/or 95.

(k) Availability of Decommissioning Funds

In accordance with 10 CFR 50.33(k) and 10 CFR 50.75(b), a decommissioning report is provided as Attachment E. This report certifies that decommissioning will be provided in an amount no less than the amount required by 10 CFR 50.75(c)(1) adjusted using a rate at least equal to that stated in 10 CFR 50.75(c)(2). This amount is currently $518,033,205. Updated certifications and financial instruments will be submitted in accordance with 10 CFR 50.75(3), and after the NRC publishes notice in the Federal Register under 10 CFR 52.103(a), the decommissioning funding amount will be adjusted annually using a rate at least equal to that stated in 10 CFR 50.75(c)(2). The decommissioning funding amount will be covered by DVP and ODEC by the external sinking fund method. Both DVP and ODEC will collect their decommissioning funding contributions through regulated, cost-of-service based rates.

FORM 10-K

VIRGINIA ELECTRIC POWER CO - VELPRE

Exhibit:

Filed: February 28, 2007 (period: December 31, 2006)

Annual report which provides a comprehensive overview of the company for the past year

Part I

PART I

PART II

PART III

PART IV

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

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2006

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

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Preferred Stock (cumulative), $100 par value, $5.00 dividend	New York Stock Exchange
7.375% Trust Preferred Securities (cumulative), $25 par value	New York Stock Exchange

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 ☒ 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 ☒

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

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

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, 2007, there were issued and outstanding 198,047 shares of the registrant's common stock, without par value, all of which were held, beneficially and of record, by Dominion Resources, Inc.

DOCUMENTS INCORPORATED BY REFERENCE.

None

VIRGINIA ELECTRIC AND POWER COMPANY

PART I

ITEM 1. BUSINESS

THE COMPANY

Virginia Electric and Power Company is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. 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 in this report and, depending on the context of their use, may refer to Virginia Electric and Power Company, one or more of its consolidated subsidiaries or operating segments or the entirety of Virginia Electric and Power Company, including all of its consolidated subsidiaries.

All of our common stock is owned by our parent company, Dominion Resources, Inc. (Dominion), a fully integrated gas and electric holding company.

As of December 31, 2006, we had approximately 6,900 full-time employees. Approximately 3,200 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 operations through three primary operating segments: Delivery, Energy and Generation. We also report corporate and other functions as a segment. While we manage our daily operations 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 25 to our Consolidated Financial Statements. For additional information on operating revenue related to our principal products and services, see Note 5 to our Consolidated Financial Statements.

Delivery

Delivery includes our electric distribution and customer service businesses. Electric distribution operations serve residential, commercial, industrial and governmental customers in Virginia and northeastern North Carolina.

COMPETITION

Within Delivery's service territory in Virginia and North Carolina, there is no competition for electric distribution service.

REGULATION

Delivery's electric retail service, including the rates it may charge to jurisdictional customers, is subject to regulation by the Virginia State Corporation Commission (Virginia Commission) and the North Carolina Utilities Commission (North Carolina Commission). See *Regulation—State Regulations* for additional information.

PROPERTIES

The Delivery segment's electric distribution network includes approximately 55,000 miles of distribution lines, exclusive of service level lines in Virginia and North Carolina. The rights-of-way grants for most of our electric lines have been obtained from the apparent owner of real estate, but underlying titles have not been examined. Where rights-of-way have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many electric lines are on publicly-owned property, where permission to operate can be revoked.

SOURCES OF ENERGY SUPPLY

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

SEASONALITY

Delivery's business varies seasonally as a result of the impact of changes in temperature on demand by residential and commercial customers for electricity to meet cooling and heating needs.

Energy

Energy includes our regulated electric transmission system serving Virginia and northeastern North Carolina. In 2005, we became a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), and integrated our electric transmission facilities into the PJM wholesale electricity markets.

COMPETITION

Since the integration of our electric transmission facilities into PJM, our electric transmission services are administered by PJM and are no longer subject to competition in relation to transmission service provided to customers within the PJM region.

REGULATION

Energy's electric transmission rates, tariffs and terms of service are subject to regulation by the Federal Energy Regulatory Commission (FERC). Electric transmission siting authority remains the exclusive jurisdiction of the Virginia and North Carolina Commissions. However, the Energy Policy Act of 2005 (EPACT) provides FERC with certain limited backstop authority for transmission siting, the implications of which remain unclear. See *Regulation—State Regulations* and *Regulation—Federal Regulations* for additional information.

PROPERTIES

The Energy segment 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 the 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 continue to own and maintain these electric transmission facilities, they are now a part of PJM, which coordinates the planning, operation, emergency assistance, and exchanges of capacity and energy for such facilities.

Each year, as part of PJM's Regional Transmission Expansion Plan (RTEP) process, reliability projects are authorized. In June 2006, PJM, through the RTEP process, authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects. The first project is an approximately 270-mile 500-kV transmission line from southwestern Pennsylvania to Virginia, of which we will construct approximately 70 miles in Virginia and a subsidiary of Allegheny Energy, Inc. will construct the remainder. The second project is an approximately 56-mile 500-kV transmission line that we will construct in southeastern Virginia. 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 will be subject to applicable state and federal permits and approvals.

SEASONALITY

Energy's business varies seasonally as a result of the impact of changes in temperature on demand by residential and commercial customers for electricity to meet cooling and heating needs.

Generation

Generation includes our portfolio of electric generation facilities, power purchase agreements and our energy supply operations. 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 system resources.

COMPETITION

For our electric generation operations, retail choice has been available for our Virginia jurisdictional electric customers since January 1, 2003; however, to date, competition in Virginia has not developed to any significant extent. See *Regulation—State Regulations*. Currently, North Carolina does not offer retail choice to electric customers.

REGULATION

The operations of our Generation segment are subject to regulation by the Virginia Commission, the North Carolina Commission, FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA), the Department of Energy (DOE), the Army Corps of Engineers and other federal, state and local authorities.

PROPERTIES

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

Based on available generation capacity and current estimates of growth in customer demand, we will need additional generation in the future. We currently have plans to restart our Hopewell plant in 2007, a 63-megawatt (Mw) (at net summer capability) coal burning plant located in Hopewell, Virginia which has been out of service since 2002, and we are evaluating a 290-Mw (at net summer capability) expansion of our Ladysmith site in Ladysmith, Virginia. We are also leading a consortium of companies that are considering building a 500 to 600-Mw coal-fired plant in southwest Virginia. We will continue to evaluate the development of new plants to meet customer demand for additional generation needs in the future.

SOURCES OF ENERGY SUPPLY

Generation uses a variety of fuels to power our electric generation, as described below. See *Segment Results of Operations—Generation* in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation (MD&A) for a summary of our generation output by energy source.

Nuclear Fuel—Generation primarily utilizes long-term contracts to support its nuclear fuel requirements. 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. 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.

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.

SEASONALITY

Sales of electricity for the Generation segment vary seasonally as a result of the impact of changes in temperature on demand by residential and commercial customers for electricity to meet cooling and heating needs.

NUCLEAR DECOMMISSIONING

Generation has four licensed, operating nuclear reactors at its Surry and North Anna plants in Virginia that serve our customers. Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power plant 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.

The total estimated cost to decommission our four nuclear units is $1.8 billion in 2006 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.

	Surry		North Anna		
	Unit 1	Unit 2	Unit 1	Unit 2	Total
(millions)					
NRC license expiration year	2032	2033	2038	2040	
Most recent cost estimate (2006 dollars)	$ 457	$ 484	$ 436	$ 458	$1,835
Funds in trusts at December 31, 2006	361	356	296	280	1,293
2006 contributions to trusts	1.4	1.5	1.0	0.9	4.8

Corporate

We also have a Corporate segment. Corporate includes our corporate and other functions and specific items attributable to our operating segments that have been excluded from the profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments. Also included in the Corporate segment are the discontinued operations of Virginia Power Energy Marketing, Inc. (VPEM), previously a subsidiary, that was transferred to Dominion in December 2005. See Notes 1, 8 and 25 to our Consolidated Financial Statements.

REGULATION

We are subject to regulation by the Virginia Commission, the North Carolina Commission, the Securities and Exchange Commission (SEC), FERC, the EPA, the DOE, the NRC, the 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 affiliates, transfers of certain facilities and issuance of securities.

Rates

Historically, our rates have been based on the cost of providing traditional bundled electric service (i.e., the combination of transmission, distribution and generation services). As a result of the Virginia Electric Utility Restructuring Act enacted in 1999 (1999 Virginia Restructuring Act), in Virginia, rates have been transitioning to unbundled cost-based rates for transmission and distribution services, and to market pricing for generation services, including retail choice for our customers. In North Carolina, rates are still based on the cost of providing traditional bundled electric service; however, our base rates are currently subject to a rate moratorium as described below.

The following is a discussion of our current rate structure; however, such structure is subject to change under proposed new restructuring legislation described under *Status of Electric Restructuring in Virginia.*

Virginia—We provide retail electric service in Virginia at unbundled rates. Our base rates are capped at 1999 levels until the sooner of (1) the end of a transition period (now December 31, 2010) or (2) a Virginia Commission order finding that a competitive market for generation exists in the Commonwealth. In 2004, the Virginia fuel factor statute was amended to lock in our fuel factor provisions until the earlier of July 1, 2007 or the termination of capped rates, with no adjustment for previously incurred over-recovery or under-recovery of fuel costs, thus eliminating deferred fuel accounting for the Virginia jurisdiction. However, in May 2006, Virginia law was amended to modify the way our Virginia jurisdictional fuel factor is set during the three and one-half year period beginning July 1, 2007. The bill became law effective July 1, 2006 and:

- Allows annual fuel rate adjustments for three twelve-month periods beginning July 1, 2007 and one six-month period beginning July 1, 2010 (unless capped rates are terminated earlier under the 1999 Virginia Restructuring Act);
- Allows an adjustment at the end of each of the twelve-month periods to account for differences between projections and actual recovery of fuel costs during the prior twelve months (thus allowing deferred fuel accounting for these periods); and
- Authorizes the Virginia Commission to defer up to 40% of any fuel factor increase approved for the first twelve-month period, with recovery of the deferred amount over the two and one-half year period beginning July 1, 2008 (under prior law, such a deferral was not possible).

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen in 2004, which has resulted in our fuel expenses being significantly in excess of our rate recovery. We expect that fuel expenses will continue to exceed rate recovery until our fuel factor is adjusted in July 2007. While the 2006 amendments do not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor is adjusted, the risk of under-recovery of prudently incurred fuel costs until July 1, 2010 is greatly diminished.

North Carolina—In connection with the North Carolina Commission's approval of Dominion's acquisition of Consolidated Natural Gas Company (CNG) in 2000, we agreed not to request an increase in North Carolina retail electric base rates before 2006, except for certain events that would have a significant financial impact on our operations. However, in 2004, the North Carolina Commission commenced an investigation into 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 reduction in current base rates and a five-year base rate moratorium, effective as of April 2005. Fuel rates are still subject to change under the annual fuel cost adjustment proceedings.

Status of Electric Restructuring in Virginia

1999 VIRGINIA RESTRUCTURING ACT

The 1999 Virginia Restructuring Act established a plan to restructure the electric utility industry in Virginia. In general, this legislation provided for a transition from bundled cost-based rates for regulated electric service to unbundled cost-based rates for transmission and distribution services and to market pricing for generation services, including retail choice for our customers. The 1999 Virginia Restructuring Act addressed capped base rates, RTO participation, retail choice, stranded costs recovery and functional separation of an electric utility's generation from its transmission and distribution operations.

Retail choice was made available to all of our Virginia regulated electric customers, commencing on January 1, 2003. We have separated our generation, distribution and transmission functions through the creation of divisions. State regulatory requirements ensure that our generation division and other divisions operate independently and prevent cross-subsidies between our generation division and other divisions. Additionally, in 2005, we became a member of PJM, an RTO, and have integrated our electric transmission facilities into the PJM wholesale electricity markets. Under the 1999 Virginia Restructuring Act, our base rates have been capped until December 31, 2010, unless modified earlier as previously discussed in *Rates.*

2004 amendments to the 1999 Virginia Restructuring Act addressed a minimum stay exemption program, a wires charge exemption program and the development of a coal-fired generating plant in southwest Virginia.

2007 VIRGINIA RESTRUCTURING ACT AMENDMENTS

In February 2007, both houses of the Virginia General Assembly passed identical bills that would significantly change electricity restructuring in Virginia. The bills would end capped rates two years early, on December 31, 2008. After capped rates end, retail choice would be eliminated for all but individual retail customers with a demand of more than 5-Mw and a limited number of non-residential retail customers whose aggregated load would exceed 5-Mw. Also after the end of capped rates, the Virginia Commis -

sion would set the base rates of investor-owned electric utilities under a modified cost-of-service model. Among other features, the currently proposed model would provide for the Virginia Commission to:

- Initiate a base rate case for each utility during the first six months of 2009, as a result of which the Virginia Commission:
  - establishes a return on equity (ROE) no lower than that reported by a group of utilities within the southeastern United States (U.S.), with certain limitations on earnings and rate adjustments;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return, if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may reduce rates or, alternatively, order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE; and
  - may authorize performance incentives if appropriate.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - establishes an ROE no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations on earnings and rate adjustments; however, if the Virginia Commission finds that such ROE limit at that time exceeds the ROE set at the time of the initial base rate case in 2009 by more than the percentage increase in the Consumer Price Index in the interim, it may reduce that lower ROE limit to a level that increases the initial ROE by only as much as the change in the Consumer Price Index;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE, and reduce rates if the utility is found to have such excess earnings during two consecutive biennial review periods; and
  - may authorize performance incentives if appropriate.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service, energy efficiency and conservation programs, and renewable energy programs; and
- Authorize an enhanced ROE as a financial incentive for construction of major baseload generation projects and for renewable energy portfolio standard programs.

The bills would also continue statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter. However, our fuel factor increase as of July 1, 2007 would be limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of that date, and the remainder would be deferred and collected over three years, as follows:

- in calendar year 2008, the deferral portion collected is limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of January 1, 2008;
- in calendar year 2009, the deferral portion collected is limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of January 1, 2009; and
- the remainder of the deferral balance, if any, would be collected in the fuel factor in calendar year 2010.

The Governor has until March 26, 2007 to sign, propose amendments to, or veto the bills. With the Governor's signature, the bills would become law effective July 1, 2007. At this time, we cannot predict the outcome of these legislative proposals.

Retail Access Pilot Programs

Three retail access pilot programs were approved by the Virginia Commission in 2003, and continue to be available to customers. There are currently six competitive suppliers and six aggregators registered with us and licensed to supply electricity to customers in Virginia. However, the current relationship between capped rates and market prices makes switching suppliers unlikely.

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 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. Various proceedings that may have a significant effect on electric transmission service rates within the PJM region are ongoing at FERC. The outcome of these cases cannot be determined with any certainty at this point in time.

We are also subject to FERC's Standards of Conduct that govern conduct between interstate gas and electricity transmission providers and their marketing function or their energy related affiliates. The rule defines the scope of the affiliates covered by the standards and is designed to prevent transmission providers from giving their marketing functions or affiliates undue preferences.

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 the North American Electric Reliability Corporation (NERC) as the ERO beginning on January 1, 2007. In late 2006, FERC also issued an initial order approving many reliability standards, also to go into effect on January 1, 2007. FERC has proposed that beginning on June 1, 2007, entities that violate standards will be subject to fines of between $1 thousand and $1 million per day, 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 a need for major expenditures beyond the normal course of business.

Environmental Regulations

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

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. For example, the EPA has established the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules, when implemented, will require significant reductions in sulfur dioxide (SO_2), nitrogen oxide (NOx) and mercury emissions from electric generating facilities. States are currently developing implementation plans, which will determine the levels and timing of required emission reductions in each of the states within which we own and operate affected generating facilities.

In 1997, the U.S. signed an International Protocol (Protocol) to limit man-made greenhouse emissions under the United Nations Framework Convention on Climate Change. However, the Protocol will not become binding unless approved by the U.S. Senate. Currently, the Bush Administration has indicated that it will not pursue ratification of the Protocol and has set a voluntary goal of reducing the nation's greenhouse gas emission intensity by 18% during the period 2002 through 2012. We expect continuing legislative efforts in the U.S. Congress seeking to target the reductions of greenhouse gas emissions.

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. Provisions also include requirements that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. Additional programs under the CWA address the impact of thermal discharges to surface waters.

From time to time, we may be identified as a potentially responsible party (PRP) to a Superfund site. See Note 21 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.

We have applied for or obtained the necessary environmental permits for the operation of our regulated facilities. Many of these permits are subject to re-issuance and continuing review.

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, that action 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 the decommissioning trusts that have been established for this purpose, see *Generation— Nuclear Decommissioning* and Note 9 to our Consolidated Financial Statements.

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 operations are weather sensitive. 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, winter storms and droughts, can be destructive, causing outages and property damage that require us to incur additional expenses.

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, or the revision or reinterpretation of existing laws or regulations, may require us to incur additional expenses.

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

We are exposed to cost-recovery shortfalls because of capped base rates and amendments to the fuel factor statute in effect in Virginia. Under the 1999 Virginia Restructuring Act, as amended, our base rates remain capped through December 31, 2010 unless sooner modified or terminated. Although this Act allows for the recovery of certain generation-related costs during the capped rates period, we remain exposed to numerous risks of cost-recovery shortfalls. These risks include exposure to stranded costs, future environmental compliance requirements, certain tax law changes, costs related to hurricanes or other weather events, inflation, the cost of obtaining replacement power during unplanned plant outages and increased capital costs.

In addition, our current Virginia fuel factor provisions are locked-in until July 1, 2007, with no deferred fuel accounting. As a result, until July 1, 2007 we are exposed to fuel price and other risks. These risks include exposure to increased costs of fuel, including purchased power costs, differences between our projected and actual power generation mix and generating unit performance (which affects the types and amounts of fuel we use) and differences between fuel price assumptions and actual fuel prices. Annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, will be instituted for three twelve-month periods beginning July 1, 2007. The Virginia Commission is authorized to defer up to 40% of any fuel factor increase approved for the first twelve-month period, with recovery of the deferred amount over the two and one-half year period beginning July 1, 2008. There will also be an adjustment for one six-month period beginning July 1, 2010. Beginning July 1, 2007, our risk of under-recovering prudently incurred expenses until July 1, 2010 is greatly diminished. Because there will be no adjustment to account for differences between projections and actual recovery of fuel costs at the end of the six-month period beginning July 1, 2010, we will be exposed to fuel price and other risks during that period. Further, after December 31, 2010 (or upon the earlier termination of capped rates), fuel cost recovery provisions will cease and we will be exposed to the fuel price and other related risks as described above.

The foregoing risks are subject to change upon the adoption, if any, of the proposed 2007 legislative amendments. The proposed legislation would end capped rates on December 31, 2008. The proposed legislation also calls for annual fuel cost recovery proceedings beginning July 1, 2007 and continuing thereafter. The first annual increase as of July 1, 2007 would be limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of that date, and the remainder would be deferred and collected in the years 2008 through 2010, as described under *Status of Electric Restructuring in Virginia* in MD&A. The Governor of Virginia has until March 26, 2007 to sign, propose amendments to, or veto the proposed legislation. We cannot predict the outcome of the legislation at this time.

There are risks associated with the operation of nuclear facilities. We operate nuclear facilities that are subject to risks, including the threat of terrorist attack and ability to dispose of spent nuclear fuel, the disposal of which is subject to complex federal and state regulatory constraints. These risks also include the cost of and 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 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, forwards, financial transmission rights, options and swaps, to manage our commodity and financial market risks. 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.

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 liquidity for capital requirements not satisfied by the cash flows from our operations. Management believes that we will maintain sufficient access to these financial markets based upon current credit ratings. 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 an economic downturn, the bankruptcy of an unrelated energy company or changes to our credit ratings. 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, 2007, our senior unsecured debt is rated BBB, positive outlook, by Standard & Poor's Ratings Services (Standard & Poor's); Baa1, stable outlook, by Moody's Investors Service (Moody's); and BBB+, 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 mortgage securing our First and Refunding Mortgage Bonds; however, only $215 million of these bonds were outstanding at December 31, 2006 and the bonds will mature on July 1, 2007.

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

Our Generation segment provides electricity for use on a wholesale and a retail level. Our Generation segment can supply electricity demand either from our generation facilities in Virginia, North Carolina and West Virginia or through purchased power contracts when needed. The following table lists our Generation segment's generating units and capability, as of December 31, 2006:

POWER GENERATION

Plant	Location	Primary Fuel Type	Net Summer Capability (Mw)
North Anna	Mineral, VA	Nuclear	1,621(a)
Surry	Surry, VA	Nuclear	1,598
Mt. Storm	Mt. Storm, WV	Coal	1,569
Chesterfield	Chester, VA	Coal	1,234
Chesapeake	Chesapeake, VA	Coal	595
Clover	Clover, VA	Coal	433(b)
Yorktown	Yorktown, VA	Coal	323
Bremo	Bremo Bluff, VA	Coal	227
Mecklenburg	Clarksville, VA	Coal	138
North Branch	Bayard, WV	Coal	74
Altavista	Altavista, VA	Coal	63
Southampton	Southampton, VA	Coal	63
Yorktown	Yorktown, VA	Oil	818
Possum Point	Dumfries, VA	Oil	786
Gravel Neck (CT)	Surry, VA	Oil	174
Darbytown (CT)	Richmond, VA	Oil	144
Chesapeake (CT)	Chesapeake, VA	Oil	115
Possum Point (CT)	Dumfries, VA	Oil	66
Low Moor (CT)	Covington, VA	Oil	48
Northern Neck (CT)	Lively, VA	Oil	44
Kitty Hawk (CT)	Kitty Hawk, NC	Oil	32
Remington (CT)	Remington, VA	Gas	580
Possum Point (CC)	Dumfries, VA	Gas	531(c)
Chesterfield (CC)	Chester, VA	Gas	397
Possum Point	Dumfries, VA	Gas	309
Elizabeth River (CT)	Chesapeake, VA	Gas	300
Ladysmith (CT)	Ladysmith, VA	Gas	290
Bellmeade (CC)	Richmond, VA	Gas	232
Gordonsville Energy (CC)	Gordonsville, VA	Gas	218
Rosemary (CC)	Roanoke Rapids, NC	Gas	165
Gravel Neck (CT)	Surry, VA	Gas	146
Darbytown (CT)	Richmond, VA	Gas	144
Bath County	Warm Springs, VA	Hydro	1,656(d)
Gaston	Roanoke Rapids, NC	Hydro	225
Roanoke Rapids	Roanoke Rapids, NC	Hydro	99
Pittsylvania	Hurt, VA	Wood	80
Other	Various	Various	15
			15,552
Purchased Capacity			2,076
		Total Capacity	**17,628**

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

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

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

(c) Includes a generating unit that we operate under a leasing arrangement.

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

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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. Management believes that the ultimate resolution of these proceedings will not have a material adverse effect on our financial position, liquidity or results of operations.

See *Regulation* in Item 1. Business, *Future Issues and Other Matters* in MD&A and Note 21 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.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Dominion Resources, Inc. (Dominion) owns all of our common stock. Restrictions on our payment of dividends are discussed in Note 19 to our Consolidated Financial Statements. We paid quarterly cash dividends on our common stock as follows:

(millions)	1st	2nd	3rd	4th	Total
2006	**$ 76**	**$ 63**	**$134**	**$76**	**$ 349**
2005	131	107	216	—	454

ITEM 6. SELECTED FINANCIAL DATA

(millions)	2006	2005(1)	2004(2)	2003(3)	2002
Operating revenue	**$ 5,603**	$ 5,712	$ 5,371	$ 5,191	$ 5,003
Income from continuing operations before cumulative effect of changes in accounting principles	**478**	485	590	556	801
Income (loss) from discontinued operations, net of tax(4)	**—**	(471)	(159)	26	(28)
Cumulative effect of changes in accounting principles, net of tax	**—**	(4)	—	(21)	—
Net income	**478**	10	431	561	773
Balance available for common stock	**462**	(6)	415	546	757
Total assets	**15,683**	15,449	17,318	16,884	15,588
Long-term debt(5)	**3,619**	3,888	4,958	4,744	3,794
Preferred securities of subsidiary trust(5)	**—**	—	—	—	400

(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. See Note 3 to our Consolidated Financial Statements.

(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) Includes $122 million of after-tax incremental restoration expenses associated with Hurricane Isabel, a $77 million after-tax charge resulting from the termination of long-term power purchase agreements and restructuring of certain electric sales contracts and a $21 million net after-tax loss for the adoption of the following accounting standards that resulted in the recognition of the cumulative effect of changes in accounting principles:

- Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*;
- Emerging Issues Task Force 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*;
- Statement 133 Implementation Issue No. C20, *Interpretation of the Meaning of 'Not Clearly and Closely Related' in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature;* and
- Financial Accounting Standards Board Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R).

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

(5) Upon adoption of FIN 46R on December 31, 2003 with respect to a special purpose entity, we began reporting as long-term debt our junior subordinated notes held by a capital trust, rather than the trust preferred securities issued by the trust.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) discusses the results of operations and general financial condition of Virginia Electric and Power Company. MD&A should be read in conjunction with our Consolidated Financial Statements. The terms "Virginia Power," "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 Electric and Power Company, one of Virginia Electric and Power Company's consolidated subsidiaries or operating segments, or the entirety of Virginia Electric and Power Company and its consolidated subsidiaries. We are a wholly-owned subsidiary of Dominion Resources, Inc. (Dominion).

CONTENTS OF MD&A

Our MD&A consists of the following information:

- Forward-Looking Statements
- Introduction
- 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 our 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 winter storms, that can cause outages and property damage to our facilities;
- State and federal legislative and regulatory developments, including a movement towards a hybrid form of regulation, and changes to environmental and other laws and regulations to which we are subject;

- Cost of environmental compliance;
- 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 price risk due to marketable securities held as investments in nuclear decommissioning trusts;
- Fluctuations in interest rates;
- 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 in rules for regional transmission organizations (RTOs) in which we participate, including changes in rate designs and new and evolving capacity models;
- Changes to our ability to recover investments made under traditional regulation through rates; and
- Political and economic conditions, including the threat of domestic terrorism, inflation and deflation.

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.

INTRODUCTION

Virginia Electric and Power Company, a Virginia public service company, is a wholly-owned subsidiary of Dominion. We are a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. We serve approximately 2.3 million retail customer accounts, including governmental agencies, and wholesale customers such as rural electric cooperatives and municipalities.

Our businesses are managed through three primary operating segments: Delivery, Energy and Generation. The contributions to net income by our primary operating segments are determined based on a measure of profit that we believe represents the segments' core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by management in assessing segment performance or allocating resources among the segments. Those specific items are reported in the Corporate segment.

Delivery includes our regulated electric distribution and customer service businesses. Our electric 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. The profitability of this business is dependent on our ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability in earnings relates largely to changes in volumes, which are primarily weather sensitive, and changes in the cost of routine maintenance and repairs (including labor and benefits).

Energy includes our regulated electric transmission system serving Virginia and northeastern North Carolina. In 2005, we became a member of PJM Interconnection, LLC (PJM), an RTO, and integrated our electric transmission facilities into the PJM wholesale electricity markets.

Revenue provided by our regulated electric transmission operations is based primarily on rates established by the Federal Energy Regulatory Commission (FERC). The profitability of this business is dependent on our ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability in earnings results from changes in rates and the demand for services, which is primarily weather dependent.

Generation includes our portfolio of electric generating facilities, power purchase agreements and our energy supply operations. Our generation mix is diversified and includes coal, nuclear, gas, oil, hydro and purchased power. 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 system resources.

Generation's earnings primarily result from the generation and sale of electricity. Due to 2004 deregulation legislation, revenues for serving Virginia jurisdictional retail load are based on capped rates through 2010 and fuel costs for the utility fleet, including power purchases, are subject to fixed rate recovery provisions until July 1, 2007, at which time fuel rates will be adjusted annually as discussed in *Status of Electric Restructuring in Virginia* in *Future Issues and Other Matters*.

Changes in our utility operating costs, particularly with respect to fuel and purchased power, relative to costs used to establish capped rates, will impact our earnings. Variability in earnings also results from changes in demand, which is primarily weather dependent, the cost of labor and benefits and the timing, duration and costs of outages.

Corporate includes our corporate and other functions, and specific items attributable to our primary operating segments that have been excluded from the profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments, including the net impact of Virginia Power Energy Marketing, Inc. (VPEM) prior to its transfer to Dominion.

On December 31, 2005, we completed the transfer of our indirect wholly-owned subsidiary, VPEM, to Dominion through a series of dividend distributions in exchange for a capital contribution. VPEM provides fuel and risk management services to us by acting as an agent for one of our other indirect wholly-owned subsidiaries. VPEM also engages in energy trading activities and provides price risk management services to other Dominion affiliates through the use of derivative contracts. While we owned VPEM, certain of these derivative contracts were required to be reported at fair value in our Consolidated Balance Sheets, with changes in fair value reflected in earnings. These price risk management activities for Dominion affiliates generated derivative gains and losses that in turn affected our Consolidated Financial Statements.

As a result of the transfer, VPEM's results of operations are no longer included in our Consolidated Financial Statements, and our Consolidated Statements of Income for periods prior to the transfer have been adjusted to reflect VPEM as a discontinued operation.

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 that also serves as our Audit Committee.

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 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 2006, 2005 and 2004, we recognized $40 million, $44 million and $42 million, respectively, of accretion and expect to incur $36 million in 2007.

A significant portion of our AROs relate to the future decommissioning of our nuclear facilities. At December 31, 2006, nuclear decommissioning AROs, which are reported in the Generation segment, totaled $603 million, representing approximately 94% of our total AROs. Based on their significance, the following discussion of critical assumptions inherent in determining the fair value of AROs relates to those associated with our nuclear decommissioning obligations.

We obtain from third-party specialists 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. In 2006, we lowered the cost escalation rate assumptions used in the ARO calculation by 0.85% due to projected reductions in both general and decommissioning specific inflation rates, resulting in a $201 million decrease in our nuclear decommissioning AROs.

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 and when revenue is collected from customers for expenditures that are not yet incurred. Regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the recovery period authorized by the regulator.

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 12 to our Consolidated Financial Statements.

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 $233 million and $263 million of accrued unbilled revenue at December 31, 2006 and 2005 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 them 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.

Through December 31, 2006, we have established liabilities for tax-related contingencies in accordance with Statement of Financial Accounting Standards (SFAS) No. 5, *Accounting for Contingencies*, and reviewed them in light of changing facts and circumstances. However, as discussed in Note 4 to our Consolidated Financial Statements, effective January 1, 2007, we adopted Financial Accounting Standards Board Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes*. 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 taxing authorities with full knowledge of all relevant information.

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.

ACCOUNTING STANDARDS

During 2006 and 2005, 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.

RESULTS OF OPERATIONS

Presented below is a summary of our consolidated results:

Year Ended December 31, (millions)	2006	$ Change	2005	$ Change	2004
Net Income	$478	$ 468	$ 10	$ (421)	$431

Overview

2006 VS. 2005

Net income increased to $478 million. Favorable drivers include the absence of $471 million of after-tax losses incurred in 2005 by the discontinued operations of VPEM and the absence of a 2005 charge resulting from the termination of a long-term power purchase agreement. Our results were also positively impacted by decreased consumption of fossil fuel due to milder weather and an increase in gains realized from the sale of emissions allowances. Unfavorable drivers include a decrease in regulated electric sales resulting from milder weather and other factors; a reduced benefit from financial transmission rights (FTRs) in excess of congestion costs and major storm damage and service restoration costs associated with tropical storm Ernesto in September 2006.

2005 VS. 2004

Net income decreased to $10 million. Unfavorable drivers include $471 million of after-tax losses incurred by the discontinued operations of VPEM and a charge resulting from the termination of a long-term power purchase agreement. Our results were also negatively affected by the impact of higher commodity prices on fuel and purchased power expenses.

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Analysis of Consolidated Operations

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

Year Ended December 31, (millions)	2006	$ Change	2005	$ Change	2004
Operating Revenue	$5,603	$ (109)	$5,712	$ 341	$5,371
Operating Expenses					
Electric fuel and energy purchases	2,384	(169)	2,553	802	1,751
Purchased electric capacity	453	(24)	477	(73)	550
Other energy-related commodity purchases	56	22	34	(4)	38
Other operations and maintenance	1,028	83	945	(294)	1,239
Depreciation and amortization	536	9	527	31	496
Other taxes	163	(7)	170	2	168
Other income	75	5	70	21	49
Interest and related charges	296	(26)	322	73	249
Income tax expense	284	15	269	(70)	339
Loss from discontinued operations, net of tax	—	471	(471)	(312)	(159)

An analysis of our results of operations for 2006 compared to 2005 and 2005 compared to 2004 follows:

2006 VS. 2005

Operating Revenue decreased 2% to $5.6 billion, reflecting the combined effects of:

- A $218 million decrease associated with milder weather. As compared to the prior year, we experienced a 9% decline in cooling degree days and a 16% decline in heating degree days; and
- A $53 million decrease in sales to wholesale customers primarily resulting from milder weather; partially offset by
- An $81 million increase due to new customer connections primarily in our residential and commercial customer classes;
- A $56 million increase attributable to rate variations resulting from changes in customer usage patterns and sales mix and other factors;
- An $18 million increase in ancillary service revenue from PJM;
- A $13 million increase due to the collection of a new Virginia sales and use tax surcharge from customers; and
- A $9 million increase primarily due to the impact of a comparatively higher fuel rate in certain customer jurisdictions which was offset by a comparable increase in *Electric fuel and energy purchases expense*.

Operating Expenses and Other Items

Electric fuel and energy purchases expense decreased 7% to $2.4 billion, primarily due to lower commodity prices, including purchased power, and decreased consumption of fossil fuel, reflecting the effects of milder weather on demand, partially offset by an increase in purchased power volumes.

Purchased electric capacity expense decreased 5% to $453 million, primarily due to scheduled capacity reductions for certain long-term power purchase contracts, as well as the termination of a long-term power purchase agreement in connection with the purchase of the related generating facility in February 2005.

Other energy-related commodity purchases expense increased 65% to $56 million, primarily reflecting an increase in nonutility coal purchased for resale.

Other operations and maintenance expense increased 9% to $1.0 billion, primarily reflecting:

- A $41 million increase due to a reduced benefit from FTRs granted by PJM used to offset congestion costs associated with PJM spot market activity, which are included in *Electric fuel and energy purchases expense*;
- A $29 million increase related to major storm damage and service restoration costs associated with our distribution operations, primarily resulting from tropical storm Ernesto in September 2006;
- A $15 million increase resulting from higher salaries, wages, and pension and medical benefits;
- A $12 million increase in outage costs primarily due to an increase in the number of scheduled outages at certain of our electric generating facilities;
- A $9 million increase due to the amortization of a regulatory asset associated with amounts subject to collection under a Virginia sales and use tax surcharge, net of credits resulting from additions to the regulatory asset during the period;
- A $7 million increase related to services provided by Dominion Resources Services, Inc.;
- A $7 million charge resulting from the write-off of certain assets no longer in use at one of our electric generating facilities; and
- A $4 million increase in PJM ancillary service charges; partially offset by
- A $20 million increase in gains from the sale of emissions allowances; and
- A net benefit from the absence of the following items recognized in 2005:
  - A $77 million charge resulting from the termination of a long-term power purchase agreement; partially offset by
  - A $25 million net benefit resulting from the establishment of certain regulatory assets in connection with the settlement of a North Carolina rate case.

Interest and related charges decreased 8% to $296 million, primarily reflecting the absence of prepayment penalties resulting from the early redemption of debt in 2005, partially offset by additional borrowings and higher interest rates on variable rate debt.

Loss from discontinued operations reflects the absence of losses incurred by the discontinued operations of VPEM prior to its disposition in December 2005.

2005 VS. 2004

Operating Revenue increased 6% to $5.7 billion, primarily reflecting:

- A $153 million increase in sales to wholesale customers;
- A $99 million increase due to the impact of a comparatively higher fuel rate in certain customer jurisdictions which was more than offset by an increase in *Electric fuel and energy purchases expense*;
- A $77 million increase primarily due to the impact of comparably favorable weather on customer usage. As compared to the prior year, we experienced an 8% increase in cooling degree days and a 3% increase in heating degree days; and
- A $59 million increase associated with new customer connections primarily in our residential and commercial customer classes; partially offset by
- A $25 million decrease attributable to rate variations resulting from changes in customer usage patterns and sales mix and other factors; and
- A $22 million decrease in other revenue, primarily attributable to a decrease in off-system sales.

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Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 46% to $2.6 billion, primarily resulting from higher commodity prices including purchased power and congestion costs associated with PJM.

Purchased electric capacity expense decreased 13% to $477 million, resulting from the termination of several long-term power purchase agreements in connection with the purchase of the related generating facilities in 2004 and 2005.

Other operations and maintenance expense decreased 24% to $945 million, primarily reflecting:

- A $186 million benefit related to FTRs;
- A $54 million gain resulting from the sale of emissions allowances; and
- A net benefit from the absence of the following items recognized in 2004:
  - A $184 million charge related to the sale of our interest in a long-term power tolling contract;
  - A $71 million charge resulting from the termination of certain long-term power purchase agreements; partially offset by
  - An $18 million benefit from the reduction of accrued expenses associated with Hurricane Isabel restoration activities.
- These benefits were partially offset by the following charges in 2005:
  - A $77 million charge resulting from the termination of a long-term power purchase agreement;
  - A $36 million increase in salaries, wages, and benefits expense, resulting from higher incentive-based compensation, wages and pension benefits; and
  - A $17 million increase in operating expenses related to nonutility generating facilities acquired subsequent to September 2004.

Depreciation and amortization expense increased 6% to $527 million, due to incremental expense resulting from property additions.

Other income increased 43% to $70 million primarily reflecting a $9 million increase in net realized gains (including investment income) associated with nuclear decommissioning trust fund investments, a $3 million increase in rental income and a $2 million increase in interest income.

Interest and related charges increased 29% to $322 million, primarily reflecting the impact of prepayment penalties resulting from the early redemption of debt, additional borrowings and higher interest rates on variable rate debt.

Loss from discontinued operations increased as a result of unfavorable price changes on unsettled commodity derivative contracts primarily used to execute price risk management activities undertaken on behalf of our affiliates.

Outlook

We believe our operating businesses will provide stable growth in net income in 2007. The following are growth factors that will impact these expected results:

- A decrease in unrecovered Virginia fuel expenses as a result of annual adjustments to our fuel factor beginning July 1, 2007;
- A potential increase in regulated electric sales, as compared to 2006, assuming our utility service territory experiences a return to normal weather in 2007; and
- Continued growth in utility customers.

The growth factors in 2007 are expected to be partially offset by:

- A decrease in gains from sales of emissions allowances;
- Increased salaries, wages and benefits expense; and
- Increased interest expense.

An important development impacting the future of our Company is the passage of legislation in Virginia that would re-regulate certain elements of our business, as discussed in *Status of Electric Restructuring in Virginia* under *Future Issues and Other Matters*. Since competitive markets have not developed in Virginia, we are supporting legislation passed by the Virginia General Assembly in early 2007 that would create a hybrid regulatory model designed to modify the traditional regulatory method to better suit it to the financial realities of undertaking major new generation and infrastructure projects. We believe this model would continue to provide our customers with comparatively low rates and ensure our ability to build new generation and other infrastructure needed to keep pace with growing demand for electricity in Virginia. The Governor has until March 26, 2007 to sign, propose amendments to, or veto the proposed legislation. With the Governor's signature, the legislation would become law effective July 1, 2007. At this time, we cannot predict the outcome of the legislation.

SEGMENT RESULTS OF OPERATIONS

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

Year Ended December 31,	**2006**	**$ Change**	2005	$ Change	2004
(millions)					
Delivery	**$270**	**$ (28)**	$ 298	$ 10	$ 288
Energy	**69**	**3**	66	(10)	76
Generation	**151**	**(24)**	175	(205)	380
Primary operating segments	**490**	**(49)**	539	(205)	744
Corporate	**(12)**	**517**	(529)	(216)	(313)
Consolidated	**$478**	**$ 468**	$ 10	$ (421)	$ 431

Delivery

Presented below are operating statistics related to our Delivery operations:

Year Ended December 31,	**2006**	**% Change**	2005	% Change	2004
Electricity delivered (million mwhrs)(1)	**79.8**	**(2)%**	81.4	4%	78.0
Degree days (electric service area):					
Cooling(2)	**1,557**	**(9)**	1,707	8	1,585
Heating(3)	**3,178**	**(16)**	3,784	3	3,682
Average electric delivery customer accounts(4)	**2,327**	**2**	2,286	2	2,244

mwhrs = megawatt hours

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

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

(3)Heating degree days (HDDs) are units measuring the extent to which the average temperature is less than 65 degrees. HDDs are calculated as the difference between the average temperature and 65 degrees.

(4)Thirteen-month average, in thousands.

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

2006 VS. 2005

(millions)	Increase (Decrease)
Regulated electric sales:	
Weather	$ (29)
Customer growth	11
Other(1)	15
Major storm damage and service restoration	(18)
2005 North Carolina rate case settlement	(6)
Interest expense	6
Other	(7)
Change in net income contribution	$ (28)

(1)Attributable to rate variations from changes in customer usage patterns and sales mix and other factors.

2005 VS. 2004

(millions)	Increase (Decrease)
Regulated electric sales:	
Weather	$ 14
Customer growth	11
Change in segment revenue allocation(1)	(2)
2005 North Carolina rate case settlement	6
Interest expense	(11)
Depreciation and amortization	(8)
Salaries, wages and benefits expense	(6)
Other	6
Change in net income contribution	$ 10

(1)A change in the seasonal allocation of electric utility base rate revenue among the primary operating segments effective January 1, 2005.

Energy

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

2006 VS. 2005

(millions)	Increase (Decrease)
Interest expense	$ 4
RTO start-up and integration costs(1)	3
Regulated electric sales:	
Weather	(5)
Customer growth	3
Other	(2)
Change in net income contribution	$ 3

(1)Reflects the absence of a charge incurred in 2005 for the write-off of certain previously deferred start-up and integration costs associated with joining an RTO.

2005 VS. 2004

(millions)	Increase (Decrease)
Interest expense	$ (3)
RTO start-up and integration costs	(3)
Salaries, wages and benefits expense	(2)
Regulated electric sales:	
Weather	3
Customer growth	2
Change in segment revenue allocation	(3)
Other	(4)
Change in net income contribution	$ (10)

Generation

Presented below are operating statistics related to our Generation operations:

Year Ended December 31,	2006	% Change	2005	% Change	2004
Electricity supplied (million mwhrs)	79.7	(2)%	81.4	4%	78.0
Degree days (electric service area):					
Cooling	1,557	(9)	1,707	8	1,585
Heating	3,178	(16)	3,784	3	3,682

The Generation segment provides electricity primarily from nuclear, coal, oil, purchased power and natural gas. Presented below is a summary of the system's output by energy source:

	2006 Source	2005 Source	2004 Source
Nuclear(1)	31%	31%	32%
Coal(2)	38	37	38
Oil	1	4	6
Purchased power, net	26	22	19
Natural gas(3)	4	5	5
Other	—	1	—
Total(4)	100%	100%	100%

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

(2)Excludes ODEC's 50% ownership interest in the Clover Power Station. The average cost of coal for 2006 Virginia in-system generation was $27.35 per mwhr.

(3)Includes natural gas used in combustion turbines that are fueled by gas.

(4)Excludes off-system sales.

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

2006 VS. 2005

	Increase (Decrease)
(millions)	
Regulated electric sales:	
Weather	$ (64)
Customer growth	24
Other[1]	17
Energy supply margin[2]	(27)
Salaries, wages and benefits expense	(10)
2005 North Carolina rate case settlement	(10)
Outage costs	(7)
Unrecovered Virginia fuel expenses	40
Sale of emissions allowances	12
Interest expense	6
Other	(5)
Change in net income contribution	$ (24)

(1)Primarily attributable to rate variations from changes in customer usage patterns and sales mix and other factors.

(2)Primarily reflects a reduced benefit from FTRs in excess of congestion costs.

2005 VS. 2004

	Increase (Decrease)
(millions)	
Unrecovered Virginia fuel expenses[1]	$ (280)
Interest expense	(24)
Salaries, wages and benefits expense	(17)
Depreciation expense	(12)
Energy supply margin[2]	40
Regulated electric sales:	
Weather	39
Customer growth	24
Change in segment revenue allocation	5
Capacity expenses	37
2005 North Carolina rate case settlement	10
Other	(27)
Change in net income contribution	$ (205)

(1)Reflects higher commodity prices including purchased power.

(2)The increase in energy supply margin reflects a benefit related to FTRs.

Corporate

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

Year Ended December 31,	2006	2005	2004
(millions)			
VPEM discontinued operations	$ —	$(471)	$(159)
Specific items attributable to operating segments	(12)	(58)	(155)
Other	—	—	1
Net expense	$ (12)	$(529)	$(313)

Specific Items Attributable to Operating Segments

Corporate includes specific items attributable to our primary operating segments that have been excluded from the profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments. See Note 25 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 sales of securities and additional long-term financing.

At December 31, 2006, we had $1.0 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 for 2006, 2005 and 2004 is presented below:

Year Ended December 31,	2006	2005	2004
(millions)			
Cash and cash equivalents at beginning of year	$ 54	$ 2	$ 46
Cash flows provided by (used in):			
Operating activities	1,080	1,496	1,129
Investing activities	(960)	(800)	(835)
Financing activities	(156)	(644)	(338)
Net increase (decrease) in cash and cash equivalents	(36)	52	(44)
Cash and cash equivalents at end of year	$ 18	$ 54	$ 2

Operating Cash Flows

In 2006, net cash provided by operating activities decreased by $416 million as compared to 2005, primarily reflecting the absence of cash provided by VPEM prior to its disposition in December 2005. We believe that our operations provide a stable source of cash flow sufficient 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 exposure as of December 31, 2006 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. Gross credit exposure is calculated prior to the application of collateral. We held no collateral for these transactions at December 31, 2006.

	Gross Credit Exposure
(millions)	
Investment grade[1]	$ 3
Non-investment grade	—
No external ratings:	
Internally rated—investment grade[2]	48
Internally rated—non-investment grade	—
Total	$ 51

(1)Designations as investment grade are based on minimum credit ratings assigned by Moody's Investors Service (Moody's) and Standard & Poor's Ratings Services (Standard & Poor's). The five largest counterparty exposures, combined, for this category represented approximately 6% of the total gross credit exposure.

(2)The five largest counterparty exposures, combined, for this category represented approximately 94% of the total gross credit exposure.

Investing Cash Flows
Significant investing activities in 2006 included:

- $925 million for environmental upgrades, routine capital improvements of generation facilities and construction and improvements of electric transmission and distribution assets;
- $550 million for purchases of securities held as investments in our nuclear decommissioning trusts; and
- $122 million for nuclear fuel expenditures; partially offset by
- $533 million of proceeds from sales of securities held as investments in our nuclear decommissioning trusts; and
- $75 million of proceeds from the sale of emissions allowances.

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 certain regulatory approvals, including authorization by the Virginia State Corporation Commission (Virginia Commission).

In December 2005, the Securities and Exchange Commission (SEC) adopted rules that modify the registration, communications and offering processes under the Securities Act of 1933. The rules streamline the shelf registration process to provide registrants with more timely access to capital. Under the new rules, we meet the definition of a well-known seasoned issuer. This allows us to use an automatic shelf registration statement to register any offering of securities, other than those for business combination transactions. Significant financing activities in 2006 included:

- $624 million for the repayment of long-term debt;
- $349 million of common dividend payments; and
- $287 million for the net repayment of short-term debt; partially offset by
- $1 billion from the issuance of long-term debt; and
- $129 million from the net issuance of affiliated current borrowings.

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. Short-term financing is supported by a $3.0 billion five-year joint revolving credit facility dated February 2006 with Dominion and Consolidated Natural Gas Company (CNG), a wholly-owned subsidiary of Dominion, 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, CNG and us and other general corporate purposes. This credit facility can also be used to support up to $1.5 billion of letters of credit.

Our financial policy precludes issuing commercial paper in excess of our supporting lines of credit. At December 31, 2006, total commercial paper outstanding supported by the joint credit facility was $1.76 billion and the total amount of letter of credit issuances was $236 million, leaving approximately $1.0 billion available for issuance.

LONG-TERM DEBT

During 2006, we issued the following long-term debt:

Type	Principal (millions)	Rate	Maturity
Senior notes	$ 550	6.00%	2036
Senior notes	450	5.40%	2016
Total long-term debt issued	$ 1,000		

During 2006, we repaid $624 million of long-term debt securities.

COMMON SHAREHOLDER'S EQUITY

In 2005, we recorded contributed capital of $633 million related to the transfer of our investment in VPEM to Dominion and $200 million in connection with the conversion of short-term borrowings. In 2004, we recorded $11 million of other paid-in capital in connection with the reduction in amounts payable to Dominion.

In 2004, we issued 20,115 shares of our common stock to Dominion for cash consideration of $500 million. We used the proceeds, in part, to pay down our $345 million affiliated short-term demand note from Dominion.

BORROWINGS FROM PARENT

We have borrowed funds from Dominion under both short-term and long-term borrowing arrangements. Our nonregulated subsidiaries had outstanding Dominion money pool borrowings totaling $140 million and $12 million at December 31, 2006 and 2005, respectively. At December 31, 2006 and 2005, our borrowings under a long-term note totaled $220 million. We incurred interest charges related to our borrowings of $10 million and $9 million at December 31, 2006 and 2005, respectively.

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.

Our credit ratings as of February 1, 2007 follow:

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

As of February 1, 2007, Fitch Ratings Ltd. (Fitch) and Moody's maintain a stable outlook, and Standard & Poor's maintains a positive outlook for their 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, 2006, our calculated debt to total capital ratio was 47%. 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, CNG or any material subsidiaries of those affiliates 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, 2006, 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, 2006, the Virginia Commission had not restricted our payment of dividends.

Certain agreements associated with our joint credit facility with Dominion and CNG 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, 2006.

See Note 16 to our Consolidated Financial Statements for a description of potential restrictions on our dividend payments in connection with the deferral of distribution payments on trust preferred securities.

Cash Flows from Discontinued Operations

The impact of VPEM's operations on our Consolidated Statements of Cash Flows is presented below. The transfer of VPEM to Dominion has not had a negative impact on our liquidity.

Year Ended December 31,	2005	2004
(millions)		
Operating cash flows	$ 365	$(289)
Investing cash flows	106	(110)
Financing cash flows	(468)	392

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, 2006. 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 current liabilities will be paid in cash in 2007.

	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
(millions)					
Long-term debt(1)	$ 1,267	$ 418	$ 270	$2,927	$ 4,882
Interest payments(2)	245	368	323	2,406	3,342
Leases	28	44	29	27	128
Purchase obligations(3):					
Purchased electric capacity for utility operations	414	745	697	2,207	4,063
Fuel to be used for utility operations	717	838	367	573	2,495
Transportation and storage	11	26	12	9	58
Other	55	24	1	—	80
Other long-term liabilities(4)	4	4	—	—	8
Total cash payments	$ 2,741	$2,467	$1,699	$8,149	$15,056

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

(2)Does not reflect our ability to defer payments related to our trust preferred securities.

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

(4)Primarily includes interest rate swap agreements. Excludes regulatory liabilities, AROs and employee benefit plan contributions that are not contractually fixed as to timing and amount. See Notes 12, 13 and 20 to our Consolidated Financial Statements. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete fiscal year.

PLANNED CAPITAL EXPENDITURES

Our planned capital expenditures are expected to total approximately $1.2 billion annually in both 2007 and 2008. We expect to fund our capital expenditures with cash from operations and a combination of securities issuances and short-term borrowings. Our annual capital expenditures for plant and equipment for 2007, including environmental upgrades and construction improvements, are expected to total approximately as follows:

- Generation and nuclear fuel: $654 million;
- Transmission: $168 million; and
- Distribution: $390 million.

Based on available generation capacity and current estimates of growth in customer demand, we will need additional generation in the future. We currently have plans to restart our Hopewell plant in 2007, a 63-megawatt (Mw) (at net summer capability) coal burning plant located in Hopewell, Virginia which has been out of service since 2002, and we are evaluating a 290-Mw (at net summer capability) expansion of our Ladysmith site in Ladysmith, Virginia. We are also leading a consortium of companies that are considering building a 500 to 600-Mw coal-fired plant in southwest Virginia. We will continue to evaluate the development of new plants to meet customer demand for additional generation needs in the future. Through 2009, we will continue to meet any additional capacity requirements through market purchases.

FUTURE ISSUES AND OTHER MATTERS

Status of Electric Restructuring in Virginia

1999 VIRGINIA RESTRUCTURING ACT

The Virginia Electric Utility Restructuring Act was enacted in 1999 (1999 Virginia Restructuring Act) and established a plan to restructure the electric utility industry in Virginia. In general, this legislation provided for a transition from bundled cost-based rates for regulated electric service to unbundled cost-based rates for transmission and distribution services and to market pricing for generation services, including retail choice for customers. The 1999 Virginia Restructuring Act addressed capped base rates, RTO participation, retail choice, stranded costs recovery and functional separation of an electric utility's generation from its transmission and distribution operations.

Retail choice was made available to all of our Virginia regulated electric customers since January 1, 2003. We have separated our generation, distribution and transmission functions through the creation of divisions. State regulatory requirements ensure that our generation division and other divisions operate independently and prevent cross-subsidies between our generation division and other divisions. Additionally, in 2005, we became a member of PJM, an RTO, and have integrated our electric transmission facilities into the PJM wholesale electricity markets. Under the 1999 Virginia Restructuring Act, our base rates have been capped until December 31, 2010, unless modified earlier.

2004 amendments to the 1999 Virginia Restructuring Act addressed a minimum stay exemption program, a wires charge exemption program and the development of a coal-fired generating plant in southwest Virginia.

VIRGINIA FUEL EXPENSES

In May 2006, Virginia law was amended to modify the way our Virginia jurisdictional fuel factor is set during the three and one-half year period beginning July 1, 2007. The bill became law effective July 1, 2006 and:

- Allows annual fuel rate adjustments for three twelve-month periods beginning July 1, 2007 and one six-month period beginning July 1, 2010 (unless capped rates are terminated earlier under the 1999 Virginia Restructuring Act);
- Allows an adjustment at the end of each of the twelve-month periods to account for differences between projections and actual recovery of fuel costs during the prior twelve months; and
- Authorizes the Virginia Commission to defer up to 40% of any fuel factor increase approved for the first twelve-month period, with recovery of the deferred amount over the two and one-half year period beginning July 1, 2008 (under prior law, such a deferral was not possible).

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen in 2004, which has resulted in our fuel expenses being significantly in excess of our rate recovery. We expect that fuel expenses will continue to exceed rate recovery until our fuel factor is adjusted in July 2007. While the 2006 amendments do not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor is adjusted, the risk of under-recovery of prudently incurred fuel costs until July 1, 2010 is greatly diminished.

STRANDED COSTS

Stranded costs are generation-related costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market. At December 31, 2006, our exposure to potential stranded costs included long-term power purchase contracts that could ultimately be determined to be above market prices; generating plants that could possibly become uneconomical in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits. We believe capped electric retail rates will provide an opportunity to recover our potential stranded costs, depending on market prices of electricity and other factors. Recovery of our potential stranded costs remains subject to numerous risks, even in the capped-rate environment. These risks include, among others, exposure to long-term power purchase commitment losses, future environmental compliance requirements, changes in certain tax laws, nuclear decommissioning costs, increased fuel costs, inflation, increased capital costs and recovery of certain other items.

The generation-related cash flows provided by the 1999 Virginia Restructuring Act are intended to compensate us for continuing to provide generation services and to allow us to incur costs to restructure such operations during the transition period. As a result, during the transition period, our earnings may increase to the extent that we can reduce operating costs for our utility generation-related operations. Conversely, the same risks affecting the recovery of our stranded costs may also adversely impact our margins during the transition period. Accordingly, we could realize the negative economic impact of any such adverse event. Using cash flows from operations during the transition period, we may further alter our cost structure or choose to make additional investments in our business.

2007 VIRGINIA RESTRUCTURING ACT AMENDMENTS

In February 2007, both houses of the Virginia General Assembly passed identical bills that would significantly change electricity restructuring in Virginia. The bills would end capped rates two years early, on December 31, 2008. After capped rates end, retail choice would be eliminated for all but individual retail customers with a demand of more than 5-Mw and a limited number of non-residential retail customers whose aggregated load would exceed 5-Mw. Also after the end of capped rates, the Virginia Commis -

sion would set the base rates of investor-owned electric utilities under a modified cost-of-service model. Among other features, the currently proposed model would provide for the Virginia Commission to:

- Initiate a base rate case for each utility during the first six months of 2009, as a result of which the Virginia Commission:
  - establishes a return on equity (ROE) no lower than that reported by a group of utilities within the southeastern United States (U.S.), with certain limitations on earnings and rate adjustments;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return, if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may reduce rates or, alternatively, order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE; and
  - may authorize performance incentives if appropriate.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - establishes an ROE no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations on earnings and rate adjustments; however, if the Virginia Commission finds that such ROE limit at that time exceeds the ROE set at the time of the initial base rate case in 2009 by more than the percentage increase in the Consumer Price Index in the interim, it may reduce that lower ROE limit to a level that increases the initial ROE by only as much as the change in the Consumer Price Index;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE, and reduce rates if the utility is found to have such excess earnings during two consecutive biennial review periods; and
  - may authorize performance incentives if appropriate.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service, energy efficiency and conservation programs, and renewable energy programs; and
- Authorize an enhanced ROE as a financial incentive for construction of major baseload generation projects and for renewable energy portfolio standard programs.

The bills would also continue statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter. However, our fuel factor increase as of July 1, 2007 would be limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of that date, and the remainder would be deferred and collected over three years, as follows:

- in calendar year 2008, the deferral portion collected is limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of January 1, 2008;
- in calendar year 2009, the deferral portion collected is limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of January 1, 2009; and
- the remainder of the deferral balance, if any, would be collected in the fuel factor in calendar year 2010.

The Govenor has until March 26, 2007 to sign, propose amendments to, or veto the bills. With the Govenor's signature, the bills would become law effective July 1, 2007. At this time, we cannot predict the outcome of these legislative proposals.

Transmission Expansion Plan

Each year, as part of PJM's Regional Transmission Expansion Plan (RTEP) process, reliability projects are authorized. In June 2006, PJM, through the RTEP process, authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects. The first project is an approximately 270-mile 500-kilovolt (kV) transmission line from southwestern Pennsylvania to Virginia, of which we will construct approximately 70 miles in Virginia and a subsidiary of Allegheny Energy, Inc. will construct the remainder. The second project is an approximately 56-mile 500-kV transmission line that we will construct in southeastern Virginia. 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 will be subject to applicable state and federal permits and approvals.

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. To the extent that environmental costs are incurred in connection with operations regulated by the Virginia Commission, during the period ending December 31, 2010, in excess of the level currently included in the Virginia jurisdictional electric retail rates, our results of operations will decrease. After that date, recovery through regulated rates may be sought for only those environmental costs related to regulated electric transmission and distribution operations and recovery, if any, through the generation component of rates will be dependent upon the market price of electricity. However, the foregoing risks are subject to change upon the adoption, if any, of the proposed 2007 Virginia Restructuring Act Amendments.

ENVIRONMENTAL PROTECTION AND MONITORING EXPENDITURES

We incurred approximately $102 million, $134 million and $115 million of expenses (including depreciation) during 2006, 2005 and 2004, respectively, in connection with environmental protection and monitoring activities and expect these expenses to be approximately $133 million and $134 million in 2007 and 2008. In addition, capital expenditures related to environmental controls were $170 million, $42 million and $84 million for 2006, 2005 and 2004, respectively. These expenditures are expected to be approximately $197 million and $142 million for 2007 and 2008.

CLEAN AIR ACT COMPLIANCE

In March 2005, the Environmental Protection Agency (EPA) Administrator signed both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules, when implemented, will require significant reductions in sulfur dioxide (SO_2), nitrogen oxide (NOx) and mercury emissions from electric generating facilities. The SO_2 and NOx emission reduction requirements are imposed in two phases with initial reduction levels targeted for 2009 (NOx) and 2010 (SO_2), and a second phase of reductions targeted for 2015 (SO_2 and NOx). The mercury emission reduction requirements are also in two phases, with initial reduction levels targeted for 2010 and a second phase of reductions targeted for 2018. The new rules allow for the use of cap-and-trade programs. States are currently developing implementation plans, which will determine the levels and timing of required emission reductions in each of the states within which we own and operate affected generating facilities. Several of these states have issued proposed regulations for the implementation of CAIR and CAMR, but only West Virginia has adopted final rules. In April 2006, legislation titled, *Air Emissions Control*, which addresses many of the requirements of CAIR and CAMR was adopted in Virginia and is more strict than the federal requirements. This legislation, however, does not serve as Virginia's final plan for the implementation of CAIR and CAMR. These regulatory and legislative actions will require additional reductions in emissions from our fossil fuel-fired generating facilities and are already addressed in our current compliance planning. In June 2005, the EPA finalized amendments to the Regional Haze Rule, also known as the Clean Air Visibility Rule (CAVR). States have not yet finalized regulations to implement CAVR. Although we anticipate that the emission reductions achieved through compliance with CAIR and CAMR will address CAVR, at this time we cannot predict with certainty any additional financial impacts of the regional haze regulations on our operations. Implementation of projects to comply with these SO_2, NOx 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 $451 million during the period 2007 through 2011.

In March 2004, the State of North Carolina filed a petition with the EPA under Section 126 of the CAA seeking additional NO_x and SO_2 reductions from electrical generating units in thir teen states, claiming emissions from those units are contributing to air quality problems in North Carolina. We have electrical generating units in two of the thirteen states. In March 2006, the EPA issued a final rulemaking through which it denied the North Carolina petition on the basis that the implementation of the CAIR adequately addresses the air quality issues identified by North Carolina. Therefore, we do not anticipate additional expenditures in relation to this matter.

CLEAN WATER ACT COMPLIANCE

In July 2004, the EPA published regulations that govern existing utilities that employ a cooling water intake structure, and that have flow levels exceeding a minimum threshold. The EPA's rule presents several compliance options. We have been evaluating information from certain of our existing power stations and had expected to spend approximately $4 million over the next two years conducting studies and technical evaluations. 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. We cannot predict the outcome of the EPA regulatory process or determine with any certainty what specific controls may be required.

FUTURE ENVIRONMENTAL REGULATIONS

From time to time, the U.S. Congress considers various legislative proposals that would require generating facilities to comply with more stringent air emissions standards. Emission reduction requirements under consideration would be phased in under periods of up to ten to fifteen years. If these new proposals are adopted, additional significant expenditures may be required.

In 1997, the U.S. signed an International Protocol (Protocol) to limit man-made greenhouse emissions under the United Nations Framework Convention on Climate Change. However, the Protocol will not become binding unless approved by the U.S. Senate. The Bush Administration has indicated that it will not pursue ratification of the Protocol and has set a voluntary goal of reducing the nation's greenhouse gas emission intensity by 18% during the period 2002 through 2012. We expect continuing legislative efforts in the U.S. Congress seeking to target the reductions of greenhouse gas emissions. The cost of compliance with the Protocol or other greenhouse gas reduction programs could be significant. Given the highly uncertain outcome and timing of future action, if any, by the U.S. federal government on this issue, we cannot predict the financial impact of future climate change actions on our operations at this time.

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. Management's Discussion and Analysis of Financial Condition and Results of Operations 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 affect our future.

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, foreign currency exchange rates, interest rates and equity security prices as described below. Commodity price risk is due to our exposure to market shifts for prices received and paid for natural gas, electricity and other commodities. We are exposed to foreign currency exchange rate risks related to our purchases of fuel and fuel services denominated in foreign currencies. Interest rate risk is generally related to our outstanding debt. In addition, we are exposed to equity price risk through various portfolios of 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, foreign currency exchange rates and interest rates.

Commodity Price Risk

To manage price risk, we primarily hold commodity-based financial derivative instruments for nontrading purposes associated with the purchase of electricity and natural gas. 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 and options that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the fair value 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 actively quoted market prices.

A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $3 million in the fair value of our non-trading commodity-based financial derivatives as of December 31, 2006. At December 31, 2005, we did not have significant exposure to commodity price risk associated with financial derivative instruments.

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.

Foreign Currency Exchange Risk

We manage our foreign exchange risk exposure associated with anticipated future purchases of nuclear fuel processing services denominated in foreign currencies by utilizing currency forward contracts. As a result of holding these contracts as hedges, our exposure to foreign currency risk is minimal. A hypothetical 10% unfavorable change in relevant foreign exchange rates would have resulted in a decrease of approximately $3 million and $6 million in the fair value of currency forward contracts held by us at December 31, 2006 and 2005, respectively.

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, 2006 and 2005, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $6 million, respectively.

Investment Price Risk

We are subject to investment price risk due to marketable securities held as investments in decommissioning trust funds. These marketable securities are managed by third-party investment managers and are reported in our Consolidated Balance Sheets at fair value. We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $36 million and $32 million in 2006 and 2005, respectively. We recorded, in AOCI, gross unrealized gains on these investments of $86 million in 2006 and net unrealized gains of $10 million in 2005.

Dominion sponsors employee pension and other postretirement benefit plans, in which our employees participate, that hold investments in trusts to fund benefit payments. To the extent that the values of investments held in these trusts decline, the effect will be reflected in our recognition of the periodic cost of such employee benefit plans and the determination of the amount of cash that we will provide to Dominion, representing 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, 2006 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

REPORT OF MANAGEMENT'S RESPONSIBILITIES

Because we are not an accelerated filer as defined in Exchange Act Rule 12b-2, we are not required to comply with Securities and Exchange Commission rules implementing Section 404 of the Sarbanes-Oxley Act of 2002 until December 31, 2007.

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

Management maintains 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. Management recognizes the inherent limitations of any system of internal control and, therefore, cannot provide absolute assurance that the objectives of the established internal controls will be met. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits. Management believes that during 2006 the system of internal control was adequate to accomplish the intended objectives.

The Consolidated Financial Statements have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, who have been engaged by Dominion's Audit Committee, which is comprised entirely of independent directors. Deloitte & Touche LLP's audit was conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States).

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.

Management recognizes its responsibility for fostering a strong ethical climate so that our affairs are conducted according to the highest standards of personal corporate conduct. This responsibility is characterized and reflected in our code of ethics, which addresses potential conflicts of interest, compliance with all domestic and foreign laws, the confidentiality of proprietary information and full disclosure of public information.

February 28, 2007

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 Resources, Inc.) and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, common shareholder's equity and comprehensive income, and of cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, the Company changed its method of accounting to adopt a new accounting standard for conditional asset retirement obligations in 2005.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 28, 2007

CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31,	2006	2005	2004
(millions)			
Operating Revenue	**$5,603**	$5,712	$5,371
Operating Expenses			
Electric fuel and energy purchases	**2,384**	2,553	1,751
Purchased electric capacity	**453**	477	550
Other energy-related commodity purchases	**56**	34	38
Other operations and maintenance:			
External suppliers	**717**	653	975
Affiliated suppliers	**311**	292	264
Depreciation and amortization	**536**	527	496
Other taxes	**163**	170	168
Total operating expenses	**4,620**	4,706	4,242
Income from operations	**983**	1,006	1,129
Other income	**75**	70	49
Interest and related charges:			
Interest expense	**266**	292	218
Interest expense—junior subordinated notes payable to affiliated trust	**30**	30	31
Total interest and related charges	**296**	322	249
Income from continuing operations before income tax expense	**762**	754	929
Income tax expense	**284**	269	339
Income from continuing operations before cumulative effect of change in accounting principle	**478**	485	590
Loss from discontinued operations (net of income tax benefit of $274 in 2005 and $99 in 2004)	**—**	(471)	(159)
Cumulative effect of change in accounting principle (net of income tax benefit of $3)	**—**	(4)	—
Net Income	**478**	10	431
Preferred dividends	**16**	16	16
Balance available for common stock	**$ 462**	$ (6)	$ 415

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

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CONSOLIDATED BALANCE SHEETS

At December 31, (millions)	2006	2005
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 18**	$ 54
Customer receivables (less allowance for doubtful accounts of $7 at both dates)	**650**	700
Affiliated receivables	**18**	7
Other receivables (less allowance for doubtful accounts of $9 at both dates)	**80**	60
Inventories (average cost method):		
Materials and supplies	**231**	207
Fossil fuel	**274**	236
Deferred income taxes	**37**	32
Prepayments	**133**	36
Other	**14**	34
Total current assets	**1,455**	1,366
Investments		
Nuclear decommissioning trust funds	**1,293**	1,166
Other	**22**	22
Total investments	**1,315**	1,188
Property, Plant and Equipment		
Property, plant and equipment	**20,771**	20,317
Accumulated depreciation and amortization	**(8,353)**	(8,055)
Total property, plant and equipment, net	**12,418**	12,262
Deferred Charges and Other Assets		
Intangible assets	**195**	160
Regulatory assets	**241**	326
Other	**59**	147
Total deferred charges and other assets	**495**	633
Total assets	**$15,683**	$15,449

At December 31, (millions)	2006	2005
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Securities due within one year	**$ 1,267**	$ 618
Short-term debt	**618**	905
Accounts payable	**418**	415
Payables to affiliates	**62**	42
Affiliated current borrowings	**140**	12
Accrued interest, payroll and taxes	**227**	288
Other	**209**	212
Total current liabilities	**2,941**	2,492
Long-Term Debt		
Long-term debt	**2,987**	3,256
Junior subordinated notes payable to affiliated trust	**412**	412
Notes payable—other affiliates	**220**	220
Total long-term debt	**3,619**	3,888
Deferred Credits and Other Liabilities		
Deferred income taxes	**2,274**	2,201
Deferred investment tax credits	**34**	49
Asset retirement obligations	**641**	834
Regulatory liabilities	**430**	409
Other	**95**	86
Total deferred credits and other liabilities	**3,474**	3,579
Total liabilities	**10,034**	9,959
Commitments and Contingencies (see Note 21)		
Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholder's Equity		
Common stock—no par, 300,000 shares authorized, 198,047 shares outstanding	**3,388**	3,388
Other paid-in capital	**887**	886
Retained earnings	**955**	842
Accumulated other comprehensive income	**162**	117
Total common shareholder's equity	**5,392**	5,233
Total liabilities and shareholder's equity	**$15,683**	$15,449

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

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CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME

	Common Stock					
(millions, except for shares)	Shares (thousands)	Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance at December 31, 2003	178	$2,888	$ 38	$ 1,405	$ 82	$4,413
Comprehensive income:						
Net income				431		431
Net deferred derivative gains—hedging activities, net of $10 tax expense					16	16
Net unrealized gains on nuclear decommissioning trust funds, net of $20 tax expense					32	32
Amounts reclassified to net income:						
Realized gains on nuclear decommissioning trust funds, net of $1 tax expense					(2)	(2)
Net derivative losses—hedging activities, net of $0.5 tax benefit					1	1
Total comprehensive income				431	47	478
Issuance of stock to parent	20	500				500
Equity contribution by parent			11			11
Tax benefit from stock awards and stock options exercised			1			1
Dividends				(534)		(534)
Balance at December 31, 2004	198	3,388	50	1,302	129	4,869
Comprehensive income:						
Net income				10		10
Net deferred derivative losses—hedging activities, net of $5 tax benefit					(8)	(8)
Net unrealized gains on nuclear decommissioning trust funds, net of $8 tax expense					13	13
Amounts reclassified to net income:						
Realized gains on nuclear decommissioning trust funds, net of $4 tax expense					(7)	(7)
Net derivative gains—hedging activities, net of $7 tax expense					(10)	(10)
Total comprehensive income				10	(12)	(2)
Equity contribution by parent			833			833
Tax benefit from stock awards and stock options exercised			3			3
Dividends				(470)		(470)
Balance at December 31, 2005	198	3,388	886	842	117	5,233
Comprehensive income:						
Net income				**478**		**478**
Net deferred derivative losses—hedging activities, net of $6 tax benefit					**(10)**	**(10)**
Unrealized gains on nuclear decommissioning trust funds, net of $40 tax expense					**62**	**62**
Amounts reclassified to net income:						
Realized gains on nuclear decommissioning trust funds, net of $7 tax expense					**(9)**	**(9)**
Net derivative losses—hedging activities, net of $2 tax benefit					**2**	**2**
Total comprehensive income				**478**	**45**	**523**
Tax benefit from stock awards and stock options exercised			**1**			**1**
Dividends				**(365)**		**(365)**
Balance at December 31, 2006	**198**	**$3,388**	**$ 887**	**$ 955**	**$ 162**	**$5,392**

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)	2006	2005	2004
Operating Activities			
Net income	$ 478	$ 10	$ 431
Adjustments to reconcile net income to net cash from operating activities:			
Net realized and unrealized derivative (gains)/losses	(2)	1,041	(25)
Depreciation and amortization	619	604	578
Deferred income taxes and investment tax credits, net	24	(267)	125
Deferred fuel expenses, net	99	76	86
Gain on sale of emissions allowances	(74)	(54)	(35)
Other adjustments to net income	(27)	9	(16)
Changes in:			
Accounts receivable	30	(149)	(135)
Affiliated accounts receivable and payable	6	(40)	—
Inventories	(62)	(18)	(64)
Pension assets	35	56	40
Accounts payable	1	253	(51)
Accrued interest, payroll and taxes	(61)	164	(15)
Margin deposit assets and liabilities	11	(69)	4
Other operating assets and liabilities	3	(120)	206
Net cash provided by operating activities	1,080	1,496	1,129
Investing Activities			
Plant construction and other property additions	(925)	(741)	(761)
Purchases of nuclear fuel	(122)	(111)	(96)
Purchases of securities	(550)	(311)	(277)
Proceeds from sales of securities	533	257	237
Proceeds from sale of emissions allowances	75	56	41
Other	29	50	21
Net cash used in investing activities	(960)	(800)	(835)
Financing Activities			
Issuance (repayment) of short-term debt, net	(287)	638	(450)
Issuance (repayment) of affiliated current borrowings, net	129	(256)	491
Issuance of long-term debt	1,000	—	—
Repayment of long-term debt	(624)	(532)	(344)
Issuance of common stock	—	—	500
Common dividend payments	(349)	(454)	(518)
Preferred dividend payments	(16)	(16)	(16)
Other	(9)	(24)	(1)
Net cash used in financing activities	(156)	(644)	(338)
Increase (decrease) in cash and cash equivalents	(36)	52	(44)
Cash and cash equivalents at beginning of year	54	2	46
Cash and cash equivalents at end of year	$ 18	$ 54	$ 2
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	$ 254	$ 307	$ 260
Income taxes	419	156	46
Noncash investing and financing activities:			
Assumption of debt related to acquisitions of nonutility generating facilities	—	62	213
Issuance of debt in exchange for electric distribution assets	—	8	—
Exchange of debt securities	—	—	106
Conversion of short-term borrowings and other amounts payable to parent to other paid-in capital	—	200	11
Transfer of investment in subsidiary to parent	—	633	—

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. NATURE OF OPERATIONS

Virginia Electric and Power Company (the Company), a Virginia public service company, is a wholly-owned subsidiary of Dominion Resources, Inc. (Dominion). We are a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. We serve approximately 2.3 million retail customer accounts, including governmental agencies and wholesale customers such as rural electric cooperatives and municipalities. In 2005, we became a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), and integrated our electric transmission facilities into the PJM wholesale electricity markets.

As discussed in Note 8, on December 31, 2005, we completed a transfer of our indirect wholly-owned subsidiary, Virginia Power Energy Marketing, Inc. (VPEM), to Dominion through a series of dividend distributions, in exchange for a capital contribution. VPEM provides fuel and risk management services to us and other Dominion affiliates and engages in energy trading activities. Through VPEM, we had trading relationships beyond the geographic limits of our retail service territory and bought and sold natural gas, electricity and other energy-related commodities. As a result of the transfer, VPEM's results of operations are no longer included in our Consolidated Financial Statements, and our Consolidated Statements of Income for periods prior to the transfer have been adjusted to reflect VPEM as a discontinued operation. In addition, the discontinued operations of VPEM are included in our Corporate segment results.

We manage our daily operations through three primary operating segments: Delivery, Energy and Generation. In addition, we report our corporate and other functions as a segment. Corporate also includes specific items attributable to our operating segments that are excluded from the profit measures evaluated by management in assessing segment 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 Electric and Power Company, one of Virginia Electric and Power Company's consolidated subsidiaries or operating segments or the entirety of Virginia Electric and Power Company, 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 accounting principles generally accepted in the United States of America (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 revenues and expenses for the periods presented. Actual results may differ from those estimates.

Our Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of the Company and our majority-owned subsidiaries, and those variable interest entities (VIEs) where we have been determined to be the primary beneficiary.

Certain amounts in our 2005 and 2004 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2006 presentation.

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, 2006 and 2005 included $233 million and $263 million, respectively, of accrued unbilled revenue based on estimated amounts of electric energy delivered but not yet billed to our utility customers. We estimate unbilled utility 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 include:

- **Regulated electric sales** consist primarily of state-regulated retail electric sales, federally-regulated wholesale electric sales and electric transmission services subject to cost-of-service rate regulation; and
- **Other revenue** consists primarily of excess generation sold at market-based rates, miscellaneous service revenue from electric distribution operations and other miscellaneous revenue.

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.

Effective January 1, 2004, the fuel factor provisions for our Virginia retail customers were locked in until July 1, 2007. Effective July 1, 2007, the fuel factor will be adjusted as discussed under *Virginia Fuel Expenses* in Note 21. Approximately 7.5% of the cost of fuel used in electric generation and energy purchases used to serve utility customers is subject to deferral accounting. Deferred costs associated with the Virginia jurisdictional portion of expenditures incurred through 2003 continue to be reported as a regulatory asset, which is expected to be recovered by July 1, 2007.

Income Taxes

We file a consolidated federal income tax return and participate in an intercompany tax allocation agreement with Dominion and its subsidiaries. Our current income taxes are based on our taxable income or loss, determined on a separate company basis. However, prior to the repeal, effective in 2006, of the Public Utility Holding Company Act of 1935 (the 1935 Act), cash payments to Dominion were limited.

Statement of Financial Accounting Standards (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. 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. 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. Deferred investment tax credits are amortized over the service lives of the properties giving rise to the credits.

At December 31, 2006, our Consolidated Balance Sheet included $105 million of prepaid federal income taxes (recorded in prepayments), $10 million of federal income taxes receivable from Dominion (recorded in deferred charges and other assets) and $26 million of state income taxes payable to Dominion (recorded in accrued interest, payroll and taxes). At December 31, 2005, our Consolidated Balance Sheet included $10 million of prepaid state income taxes (recorded in prepayments), $55 million of prepaid federal income taxes (recorded in deferred charges and other assets), $113 million of federal income taxes payable to Dominion (recorded in accrued interest, payroll and taxes) and $11 million of federal income taxes payable to Dominion (recorded in deferred credits and other liabilities).

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. At December 31, 2006 and 2005, accounts payable included $33 million and $39 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 financial transmission rights (FTRs) to manage the commodity 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.

We hold certain derivative instruments that are not held for trading purposes and are not designated as hedges for accounting purposes. However, to the extent we do not hold offsetting positions for such derivatives, we believe these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices, interest rates and foreign exchange rates.

Statement of Income Presentation:

- **Financially-Settled Derivatives—Not Held for Trading Purposes and Not Designated as Hedging Instruments:** All unrealized changes in fair value and settlements are presented in other operations and maintenance expense on a net basis.
- **Physically-Settled Derivatives—Not Held for Trading Purposes and Not Designated as Hedging Instruments:** All unrealized changes in fair value and settlements for physical derivative sales contracts are presented in revenues, while all unrealized changes in fair value and settlements for physical derivative purchase contracts are presented in expenses.

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

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 may elect to 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.

Cash Flow Hedges—A portion of our hedge strategies represent cash flow hedges of the variable price risk associated with the purchase of natural gas and electricity. We also use foreign currency forward 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 accumulated other comprehensive income (loss) (AOCI), to the extent they are effective at offsetting changes in the hedged item, until earnings are affected by the hedged item. For cash flow hedge transactions, we discontinue hedge accounting if the occurrence of the forecasted transaction is determined to be no longer probable. We reclassify any derivative gains or losses reported in AOCI to earnings when the forecasted item is included in earnings, if it should occur, or earlier, if it becomes probable that the forecasted transaction will not occur.

Fair Value Hedges—Prior to the transfer of VPEM, we also used fair value hedges to mitigate the fixed price exposure inherent in certain natural gas inventory. We continue to use designated interest rate swaps as fair value hedges to manage our interest rate exposure on certain fixed-rate long-term debt. 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.

Statement of Income Presentation—Gains and losses on derivatives designated as hedges, when recognized, are included in operating revenue, operating expenses or interest and related charges in our Consolidated Statements of Income. Specific line item classification is determined based on the nature of the risk underlying individual hedge strategies. The portion of gains or losses on hedging instruments determined to be ineffective and the portion of gains or losses on hedging instruments excluded from the measurement of the hedging relationship's 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, are included in other operations and maintenance expense.

As discussed in Note 8, on December 31, 2005 we completed the transfer of VPEM to Dominion. VPEM manages a portfolio of commodity contracts held for trading and nontrading purposes. As a result of the transfer of VPEM to Dominion, these derivatives are no longer included in our Consolidated Financial Statements, and our Consolidated Statements of Income for periods prior to the transfer have been adjusted to reflect VPEM as a discontinued operation.

VALUATION METHODS

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, we must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis.

For options and contracts with option-like characteristics where pricing information is not available from external sources, 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 estimate fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. If pricing information is not available from external sources, judgment is required to develop the estimates of fair value. For individual contracts, the use of different valuation models or assumptions could have a material effect on the contract's estimated fair value.

Nuclear Decommissioning Trust Funds

We account for and classify all investments in marketable debt and equity securities held by our nuclear decommissioning trusts as available-for-sale securities. Available-for-sale securities are reported at fair value with realized gains and losses and any other- than-temporary declines in fair value included in other income and unrealized gains and losses reported as a component of AOCI, net of tax.

We analyze all securities classified as available-for-sale to determine whether a decline in fair value should be considered other than temporary. Prior to 2006, we used 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 was determined to be other than temporary, the security was written down to its fair value at the end of the reporting period.

In 2006, we changed our method of assessing other-than-temporary declines such that the intent and ability to hold individual securities for a period of time sufficient to allow for the anticipated recovery in their market value must be demonstrated prior to the consideration of the other criteria mentioned above. Since regulatory authorities limit our 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. 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, including labor, materials, asset retirement costs and other direct and indirect costs including capitalized interest. The cost of repairs and maintenance, including minor additions and replacements, is charged to expense as it is incurred. In 2006, 2005 and 2004, we capitalized interest costs of $10 million, $6 million and $7 million, respectively. In 2006, 2005 and 2004, for electric distribution and electric transmission property subject to cost-of-service utility rate regulation, we capitalized an allowance for funds used during construction of $11 million, $2 million and $2 million, respectively.

For electric distribution and electric transmission property subject to cost-of-service rate regulation, the depreciable cost of such property, less salvage value, is charged to accumulated depreciation at retirement. Cost of removal collections from utility customers and expenditures not representing asset retirement obligations (AROs) are recorded as regulatory liabilities or regulatory assets.

For generation-related and nonutility property, cost of removal not associated with AROs is charged to expense as incurred. We record gains and losses upon retirement of generation-related and nonutility property based upon the difference between 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:

(percent)	**2006**	2005	2004
Generation	**2.07**	2.04	1.97
Transmission	**1.97**	1.97	1.97
Distribution	**3.45**	3.46	3.46
General and other	**4.93**	5.43	5.76

Our nonutility property, plant and equipment is depreciated using the straight-line method over 25 years.

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 Environmental Protection Agency (EPA) and permit the holder of the allowance to emit certain gaseous by-products of fossil fuel combustion, including sulfur dioxide (SO_2) and nitrogen oxide (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 they are consumed, 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 and when revenue is collected from customers for expenditures that are not yet incurred. Regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the recovery 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. 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. We report the accretion of the AROs due to the passage of time 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

2006

SAB 108

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements.* SAB 108 provides guidance on how prior year misstatements should be taken into consideration when quantifying misstatements in current year financial statements for purposes of determining whether the current year's financial statements are materially misstated. Our adoption of SAB 108 on December 31, 2006 had no impact on our Consolidated Financial Statements.

2005

FIN 47

We adopted Financial Accounting Standards Board (FASB) Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47) on December 31, 2005. FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when the obligation is incurred—generally upon acquisition, construction, or development and/or through the normal operation of the asset, if the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Uncertainty about the timing and/or method of settlement is required to be factored into the measurement of the liability when sufficient information exists. Our adoption of FIN 47 resulted in the recognition of an after-tax charge of $4 million, representing the cumulative effect of the change in accounting principle.

Presented below is our pro forma net income for 2005 and 2004 as if we had applied the provisions of FIN 47 as of January 1, 2004:

Year Ended December 31	2005	2004
(millions)		
Net income—as reported	$ 10	$431
Net income—pro forma	13	431

If we had applied the provisions of FIN 47 as of January 1, 2004, our asset retirement obligations would have increased by $8 million as of January 1, 2004 and December 31, 2004.

NOTE 4. RECENTLY ISSUED ACCOUNTING STANDARDS

FIN 48

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). Taking into consideration the uncertainty and judgement involved in the determination and filing of income taxes, FIN 48 establishes standards for recognition and measurement, in the 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 taxing authorities with full knowledge of all relevant information.

Beginning in 2007, FIN 48 requires disclosures about positions taken by an entity in its tax returns that are not recognized in its financial statements, descriptions of open tax years by major jurisdiction and reasonably possible significant changes in the amount of unrecognized tax benefits that could occur in the next twelve months.

With the adoption of FIN 48, we estimate that the cumulative effect of the change in accounting principle will not have a material impact on the beginning balance of our retained earnings as of January 1, 2007.

SFAS NO. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability and establishes a fair value hierarchy of three levels that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data. SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy. The provisions of SFAS No. 157 will become effective for us beginning January 1, 2008. Generally, the provisions of this statement are to be 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 is required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses under Emerging Issues Task Force (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.* We are currently evaluating the impact that SFAS No. 157 will have on our results of operations and financial condition.

SFAS NO. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities.* 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. The provisions of SFAS No. 159 will become effective for us beginning January 1, 2008. Early adoption is permitted provided that an election is also made to apply the provisions of SFAS No. 157. We are currently evaluating the impact that SFAS No. 159 may have on our results of operations and financial condition.

NOTE 5. OPERATING REVENUE

Our operating revenue consists of the following:

Year Ended December 31,	**2006**	2005	2004
(millions)			
Regulated electric sales	**$5,451**	$5,543	$5,180
Other	**152**	169	191
Total operating revenue	**$5,603**	$5,712	$5,371

NOTE 6. INCOME TAXES

Details of income tax expense for continuing operations were as follows:

Year Ended December 31,	**2006**	2005	2004
(millions)			
Current expense:			
Federal	**$213**	$157	$184
State	**47**	40	53
Total current	**260**	197	237
Deferred expense:			
Federal	**29**	88	121
State	**10**	(1)	(3)
Total deferred	**39**	87	118
Amortization of deferred investment tax credits	**(15)**	(15)	(16)
Total income tax expense	**$284**	$269	$339

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

Year Ended December 31,	**2006**	2005	2004
U.S statutory rate	**35.0%**	35.0%	35.0%
Increases (reductions) resulting from:			
State income tax, net of federal tax benefit	**4.8**	3.4	3.5
Amortization of investment tax credits	**(1.5)**	(1.6)	(1.3)
Employee benefits	**(0.2)**	(0.6)	(0.5)
Other, net	**(0.8)**	(0.5)	(0.2)
Effective tax rate	**37.3%**	35.7%	36.5%

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:

At December 31,	**2006**	2005
(millions)		
Deferred income taxes:		
Total deferred income tax assets	**$ 161**	$ 148
Total deferred income tax liabilities	**2,398**	2,318
Total net deferred income tax liabilities	**$2,237**	$2,170
Total deferred income taxes:		
Depreciation method and plant basis differences	**$2,072**	$1,979
Deferred state income taxes	**187**	174
Unrealized gains on available-for-sale securities	**81**	53
Loss and credit carryforwards	**(63)**	(53)
Other	**(40)**	17
Total net deferred income tax liabilities	**$2,237**	$2,170

At December 31, 2006, we had federal and state minimum tax credits of $58 million that do not expire and other federal and state income tax credits of $2 million that will expire if unutilized by 2025.

We are routinely audited by federal and state tax authorities. We establish liabilities for tax-related contingencies and review them in light of changing facts and circumstances. Although the results of these audits are uncertain, we believe that the ultimate outcome will not have a material adverse effect on our financial position. At December 31, 2006 and 2005, our Consolidated Balance Sheets included no material income tax-related contingent liabilities.

American Jobs Creation Act of 2004 (the Act)

The Act has several provisions for energy companies, including a deduction related to taxable income derived from qualified production activities. Our electric generation activities qualify as production activities under the Act. The Act limits the deduction to the lesser of taxable income derived from qualified production activities or the consolidated federal taxable income of Dominion and its subsidiaries. Our qualified production activities deduction for 2006 is minimal.

NOTE 7. HEDGE ACCOUNTING ACTIVITIES

We are exposed to the impact of market fluctuations in the price of natural gas, electricity and other energy-related products purchased, as well as currency exchange and interest rate risks of our business operations. We use derivative instruments to manage our exposure to these risks and designate derivative instruments as fair value or cash flow hedges for accounting purposes as allowed by SFAS No. 133.

For the year ended December 31, 2006, there were no gains or losses on hedging instruments that were determined to be ineffective. For the year ended December 31, 2005, we recognized in net income $11 million of gains as hedge ineffectiveness and $4 million of gains attributable to differences between spot prices and forward prices that are excluded from the measurement of effectiveness, in connection with fair value hedges of natural gas inventory. The 2005 activity was related to the discontinued operations of VPEM.

The following table presents selected information related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at December 31, 2006:

	AOCI After-Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
(millions)			
Natural gas	$ (2)	$ (2)	3 months
Electricity	(2)	(2)	3 months
Interest rate	1	—	106 months
Foreign currency	15	7	9 months
Total	$ 12	$ 3	

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. DISCONTINUED OPERATIONS—VPEM TRANSFER

On December 31, 2005, we completed the transfer of VPEM to Dominion through a series of dividend distributions. This resulted in a transfer of our negative investment in VPEM to Dominion in exchange for a capital contribution of $633 million. No gain or loss was recognized on the transfer.

VPEM provides fuel and risk management services to us by acting as an agent for one of our indirect wholly-owned subsidiaries. VPEM also engages in energy trading activities and provides price risk management services to other Dominion affiliates through the use of derivative contracts. While we owned VPEM, certain of these derivative contracts were reported at fair value in our Consolidated Balance Sheets, with changes in fair value reflected in earnings. These price risk management activities performed on behalf of Dominion affiliates generated derivative gains and losses that affected our Consolidated Financial Statements.

As a result of the transfer, VPEM's results of operations are no longer included in our Consolidated Financial Statements, and our Consolidated Statements of Income for periods prior to the transfer have been adjusted to reflect VPEM as a discontinued operation, on a net basis. For 2005 and 2004, our discontinued operations included operating revenue of $807 million and $373 million, respectively, and a loss before income taxes of $746 million and $259 million, respectively. VPEM's 2005 and 2004 results included the following affiliated transactions:

Year Ended December 31,	2005	2004
(millions)		
Purchases of natural gas, gas transportation and storage services from affiliates	$1,241	$1,150
Sales of natural gas to affiliates	1,371	919
Net realized losses on affiliated commodity derivative contracts	(32)	(11)
Affiliated interest and related charges	18	6

NOTE 9. NUCLEAR DECOMMISSIONING TRUST FUNDS

We hold marketable debt and equity securities in nuclear decommissioning trust funds to fund future decommissioning costs for our nuclear plants. Our decommissioning trust funds, as of December 31, 2006 and 2005, are summarized below:

	Fair Value	Total Unrealized Gains included in AOCI	Total Unrealized Losses included in AOCI (1)
(millions)			
2006			
Equity securities	**$ 833**	**$ 239**	**$ —**
Debt securities	**425**	**7**	**—**
Cash and other	**35**	**—**	**—**
Total	**$1,293**	**$ 246**	**$ —**
2005			
Equity securities	$ 740	$ 168	$ 9
Debt securities	399	5	4
Cash and other	27	—	—
Total	$1,166	$ 173	$ 13

(1)In 2005, approximately $2 million of unrealized losses relate primarily to equity securities in a loss position for greater than one year.

The fair values of debt securities within the nuclear decommissioning trust funds at December 31, 2006 by contractual maturity are as follows:

(millions)	Amount
Due in one year or less	$ 9
Due after one year through five years	123
Due after five years through ten years	125
Due after ten years	168
Total	$ 425

Gross realized gains on the sale of available-for-sale securities totaled $49 million, $19 million and $27 million in 2006, 2005 and 2004, respectively, and gross realized losses totaled $33 million, $8 million and $24 million in 2006, 2005 and 2004, respectively. In determining realized gains and losses, the cost of these securities was determined on a specific identification basis.

NOTE 10. PROPERTY, PLANT AND EQUIPMENT

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

At December 31,	2006	2005
(millions)		
Utility:		
Generation	$10,088	$10,243
Transmission	1,777	1,671
Distribution	6,613	6,338
Nuclear fuel	907	870
General and other	592	551
Plant under construction	787	637
Total utility	20,764	20,310
Nonutility—other	7	7
Total property, plant and equipment	$20,771	$20,317

Jointly-Owned Utility Plants

Our proportionate share of jointly-owned utility plants at December 31, 2006 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	$ 1,017	$ 1,998	$ 553
Accumulated depreciation	(406)	(964)	(132)
Nuclear fuel	—	399	—
Accumulated amortization of nuclear fuel	—	(331)	—
Plant under construction	10	63	4

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 11. INTANGIBLE ASSETS

All of our intangible assets are subject to amortization over their estimated useful lives. Amortization expense for intangible assets was $37 million, $38 million and $27 million for 2006, 2005 and 2004, respectively. In 2006, we acquired $58 million of emissions allowances with an estimated weighted-average amortization period of 3.8 years. The components of our intangible assets are as follows:

At December 31,	2006		2005	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
(millions)				
Software and software licenses	$259	$ 165	$250	$ 138
Emissions allowances	63	4	7	1
Other	52	10	55	13
Total	$374	$ 179	$312	$ 152

Annual amortization expense for intangible assets is estimated to be $48 million for 2007, $30 million for 2008, $23 million for 2009, $28 million for 2010 and $12 million for 2011.

NOTE 12. REGULATORY ASSETS AND LIABILITIES

Our regulatory assets and liabilities include the following:

December 31,	2006	2005
(millions)		
Regulatory assets:		
Deferred cost of fuel used in electric generation(1)	$ 72	$171
RTO start-up costs and administration fees(2)	66	39
Income taxes recoverable through future rates(3)	46	46
Termination of certain power purchase agreements(4)	22	24
Cost of decommissioning DOE uranium enrichment facilities(5)	7	16
Other	28	30
Total regulatory assets	$241	$326
Regulatory liabilities:		
Provision for future cost of removal(6)	$409	$388
Other	21	21
Total regulatory liabilities	$430	$409

(1)In connection with the settlement of the 2003 Virginia fuel rate proceeding, we agreed to recover previously incurred costs through June 30, 2007 without a return on a portion of the unrecovered balance. Remaining costs to be recovered totaled $56 million at December 31, 2006.

(2)The Federal Energy Regulatory Commission (FERC) has conditionally authorized our deferral of start-up costs incurred in connection with joining an RTO and on-going administration fees paid to PJM. We have deferred $58 million in start-up costs and administration fees and $8 million of associated carrying costs. We expect recovery from Virginia jurisdictional retail customers to commence at the end of the Virginia retail rate cap period, subject to regulatory approval.

(3)Income taxes recoverable through future rates resulting from the recognition of additional deferred income taxes, not recognized under ratemaking practices.

(4)The North Carolina Utilities Commission (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.

(5)The cost of decommissioning the Department of Energy's (DOE) uranium enrichment facilities represents the unamortized portion of our required contributions to a fund for decommissioning and decontaminating the DOE's uranium enrichment facilities. The contributions began in June 1992 and will continue over a 15-year period with escalation for inflation. These costs are currently being recovered in fuel rates through June 30, 2007.

(6)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.

At December 31, 2006, approximately $143 million of our regulatory assets represented past expenditures on which we do not earn a return. These expenditures consist primarily of RTO start-up costs and administration fees, the cost of terminating certain power purchase agreements and a portion of deferred fuel costs.

NOTE 13. 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 determined by our operational planning. The changes to our AROs during 2006 were as follows:

	Amount
(millions)	
Asset retirement obligations at December 31, 2005	$ 834
Accretion	40
Revisions in estimated cash flows(1)	(233)
Asset retirement obligations at December 31, 2006	$ 641

(1)Primarily reflects a reduction in cost escalation rate assumptions that were applied to updated decommissioning cost studies, which reflected increases in base year costs, received for each of our nuclear facilities during the third quarter of 2006.

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2006 and 2005, the aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $1.3 billion and $1.2 billion, respectively.

NOTE 14. VARIABLE INTEREST ENTITIES

FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R) addresses the consolidation of 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.

Certain variable pricing terms in some of our long-term power and capacity contracts cause them to be considered potential variable interests in the counterparties. Two potential VIEs, with which we have existing power purchase agreements (signed prior to December 31, 2003), have not provided sufficient information for us to perform our FIN 46R evaluation.

As of December 31, 2006, no further information has been received from the two remaining potential VIEs. We will continue our efforts to obtain information and will complete an evaluation of our relationship with each of these potential VIEs if sufficient information is ultimately obtained. We have remaining purchase commitments with these two potential VIE supplier entities of $1.3 billion at December 31, 2006. We are not subject to any risk of loss from these VIEs, other than the remaining purchase commitments. We paid $98 million, $106 million and $111 million for electric generation capacity and $75 million, $102 million and $59 million for electric energy from these entities for the years ended December 31, 2006, 2005 and 2004, respectively.

In February 2006, we restructured three long-term power purchase contracts with two VIEs, of which we are not the primary beneficiary. The restructured contracts expire between 2015 and 2017. Total debt held by the entities is approximately $299 million. We have remaining purchase commitments with these two VIE supplier entities of $1 billion at December 31, 2006. We are not subject to any risk of loss from these VIEs, other than the remaining purchase commitments. We paid $116 million, $116 million and $114 million for electric generation capacity and $55 million, $57 million and $47 million for electric energy from these entities for the years ended December 31, 2006, 2005 and 2004, respectively.

During 2005, we entered into four long-term contracts with unrelated limited liability companies (LLCs) to purchase synthetic fuel produced from coal. Certain variable pricing terms in the contracts protect the equity holders from variability in the cost of their coal purchases, and therefore, the LLCs were determined to be VIEs. After completing our FIN 46R analysis, we concluded that although our interests in the contracts, as a result of their pricing terms, represent variable interests in the LLCs, we are not the primary beneficiary. We paid $341 million and $205 million to the LLCs for coal and synthetic fuel produced from coal for the years ended December 31, 2006 and 2005, respectively. We are not subject to any risk of loss from the contractual arrangements, as our only obligation to the VIEs is to purchase the synthetic fuel that the VIEs produce according to the terms of the applicable purchase contracts.

Our Consolidated Balance Sheets as of December 31, 2006 and 2005 reflect net property, plant and equipment of $337 million and $348 million, respectively and $370 million of debt, related to the consolidation, in accordance with FIN 46R, of a variable interest lessor entity through which we have financed and leased a power generation project. The debt is non-recourse to us and is secured by the entity's property, plant and equipment. The lease under which we operate the power generation facility terminates in August 2007. We intend to take legal title to the facility through repayment of the lessor's related debt at the end of the lease term.

NOTE 15. 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. Short-term financing is supported by a $3.0 billion five-year joint revolving credit facility dated February 2006 with Dominion and Consolidated Natural Gas Company (CNG), a wholly-owned subsidiary of Dominion, 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, CNG and us and 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, 2006, total outstanding commercial paper supported by the joint credit facility was $1.76 billion, of which our borrowings were $618 million, with a weighted average interest rate of 5.41%. At December 31, 2005, total outstanding commercial paper supported by the previous joint credit facility was $1.4 billion, of which our borrowings were $905 million, with a weighted average interest rate of 4.46%.

At December 31, 2006, total outstanding letters of credit supported by the joint credit facility was $236 million, of which less than $1 million were issued on our behalf. At December 31, 2005, total outstanding letters of credit supported by the previous joint credit facility was $892 million, of which less than $1 million were issued on our behalf.

At December 31, 2006, capacity available under the joint credit facility was $1.0 billion.

NOTE 16. LONG-TERM DEBT

At December 31,	2006 Weighted Average Coupon(1)	2006	2005
(millions, except percentages)			
Long-Term Debt			
Secured First and Refunding Mortgage Bonds, 7.625%, due 2007 (2):		$ 215	$ 215
Secured Bank Debt:			
Variable rate, due 2007(3)	5.85%	370	370
Unsecured Senior and Medium-Term Notes:			
4.5% to 5.75%, due 2006 to 2010	5.22%	1,000	1,600
4.75% to 8.625%, due 2013 to 2036	5.62%	1,748	762
Unsecured Callable and Puttable Enhanced Securities℠, 4.10% due 2038(4)		225	225
Tax-Exempt Financings (5):			
Variable rate, due 2008	3.69%	60	60
Variable rates, due 2015 to 2027	3.63%	137	137
4.95% to 7.65%, due 2007 to 2010	5.50%	232	237
2.3% to 7.55%, due 2014 to 2031	5.02%	263	263
Notes Payable to Affiliates:			
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.375%, due 2042		412	412
Note Payable to Dominion, 2.125%, due 2023		220	220
		4,882	4,501
Fair value hedge valuation(6)		(8)	(8)
Amount due within one year	5.92%	(1,267)	(618)
Unamortized discount and premium, net		12	13
Total long-term debt		$ 3,619	$3,888

(1)Represents weighted-average coupon rates for debt outstanding as of December 31, 2006.

(2)Substantially all of our property is subject to the lien of the mortgage, securing our mortgage bonds.

(3)Represents debt associated with a special purpose lessor entity that is consolidated in accordance with FIN 46R. The debt is nonrecourse to us and is secured by the entity's property, plant and equipment, which totaled $337 million and $348 million at December 31, 2006 and 2005, respectively.

(4)On December 15, 2008, the securities are subject to redemption at par plus accrued interest, unless holders of related options exercise rights to purchase and remarket the notes.

(5)These financings relate to certain pollution control equipment at our generating facilities. The variable rate tax-exempt financings are supported by a stand-alone $3 billion five-year credit facility that terminates in February 2011. In February 2007, we exercised our call option and redeemed $62 million of our tax-exempt financings with a weighted average rate of 7.52%, with proceeds raised through the issuance of commercial paper.

(6)Represents the valuation of certain fair value hedges associated with our fixed-rate debt.

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, 2006 were as follows:

2007	2008	2009	2010	2011	Thereafter	Total
(millions)						
$1,267	$290	$128	$250	$ 20	$ 2,927	$4,882

Our short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2006, 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 hold 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 constitute 100% of the trust's assets. The trust must redeem its trust preferred securities when the junior subordinated notes are repaid or if redeemed prior to maturity.

Distribution payments on the trust preferred securities are considered to be fully and unconditionally guaranteed by the Company when all of the related agreements are taken into consideration. Each guarantee agreement only provides for the guarantee of distribution payments on the trust preferred securities to the extent that the trust has funds legally and immediately available to make distributions. The trust's ability to pay amounts when they are due on the trust preferred securities is dependent solely upon our payment of amounts when they are due on the junior subordinated notes. If the payment on the junior subordinated notes is deferred, we may not make distributions related to our capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, we may not make any payments on, redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the junior subordinated notes.

NOTE 17. PREFERRED STOCK

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, 2006 and 2005. 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, 2006:

Dividend	Issued and Outstanding Shares	Entitled Per Share Upon Liquidation
	(thousands)	
$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	102.47(1)
6.98	600	102.45(2)
Flex MMP 12/02, Series A	1,250	100.00(3)
Total	2,590	

(1)Through 7/31/2007; $102.12 commencing 8/1/2007; amounts decline in steps thereafter to $100.00 by 8/1/2013.

(2)Through 8/31/2007; $102.10 commencing 9/1/2007; amounts decline in steps thereafter to $100.00 by 9/1/2013.

(3)Dividend rate is 5.50% through 12/20/2007; after which, the rate will be determined according to periodic auctions for periods established by us at the time of the auction process. This series is not callable prior to 12/20/2007.

NOTE 18. SHAREHOLDER'S EQUITY

Common Stock

In 2004, as approved by the Virginia State Corporation Commission (Virginia Commission), Dominion made an equity investment in the Company through the purchase of our common stock. We issued 20,115 shares of our common stock to Dominion for cash consideration of $500 million.

Other Paid-In Capital

In 2005, we recorded contributed capital of $633 million related to the transfer of our investment in VPEM to Dominion and $200 million in connection with the conversion of short-term borrowings. In 2004, we recorded $11 million of other paid-in capital in connection with the reduction in amounts payable to Dominion.

Accumulated Other Comprehensive Income

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

At December 31,	2006	2005
(millions)		
Net unrealized gains on derivatives—hedging activities, net of tax	$ 12	$ 20
Net unrealized gains on nuclear decommissioning trust funds, net of tax	150	97
Total accumulated other comprehensive income	$162	$117

NOTE 19. 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, 2006, the Virginia Commission had not restricted our payment of dividends.

Certain agreements associated with our joint credit facility with Dominion and CNG 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, 2006.

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

NOTE 20. 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 generally contribute annually an amount that is in accordance with the provisions of the Employment Retirement Income Security Act of 1974. Our net periodic pension cost was $63 million, $56 million and $40 million in 2006, 2005 and 2004, respectively. We did not contribute to the pension plan in 2006, 2005 or 2004.

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 $37 million, $42 million and $44 million in 2006, 2005 and 2004, respectively.

Certain regulatory authorities have held that amounts recovered in rates for other postretirement benefits in excess of benefits actually paid during the year must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, we fund postretirement benefit costs through Voluntary Employees' Beneficiary Associations. Our contributions to retiree health care and life insurance plans were $24 million, $32 million and $34 million in 2006, 2005 and 2004, respectively. We expect to contribute $13 million to retiree health care and life insurance plans in 2007.

We also participate in Dominion-sponsored employee savings plans that cover substantially all employees. Employer matching contributions of $11 million each were incurred in 2006, 2005 and 2004.

NOTE 21. 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. We believe that the final disposition of these proceedings will not have a material effect on our financial position, liquidity or results of operations.

Long-Term Purchase Agreements

At December 31, 2006, 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:

	2007	2008	2009	2010	2011	Thereafter	Total
(millions)							
Purchased electric capacity(1)	$414	$383	$362	$349	$348	$ 2,207	$4,063

(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, 2006, the present value of our total commitment for capacity payments is $2.6 billion. Capacity payments totaled $437 million, $472 million and $570 million, and energy payments totaled $291 million, $378 million and $293 million for 2006, 2005, and 2004, 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 (CPI). 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, 2006 are as follows:

2007	2008	2009	2010	2011	Thereafter	Total
(millions)						
$28	$25	$19	$16	$13	$27	$128

Rental expense totaled $34 million, $32 million and $40 million for 2006, 2005 and 2004, respectively, the majority of which is reflected in other operations and maintenance expense.

Environmental Matters

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

To the extent that environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 2010, in excess of the level currently included in Virginia jurisdictional rates, our results of operations will decrease. After that date, we may seek recovery through rates of only those environmental costs related to our transmission and distribution operations. However, the foregoing risks are subject to change upon the adoption, if any, of the proposed 2007 Virginia Restructuring Act Amendments as discussed later under *2007 Virginia Restructuring Act Amendments.*

SUPERFUND SITES

From time to time, we may be identified as a potentially responsible party (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.

In 1987, we and a number of other entities were identified by the EPA as PRPs at two Superfund sites located in Kentucky and Pennsylvania. In 2003, the EPA issued its Certificate of Completion of remediation for the Kentucky site. Future costs for the Kentucky site will be limited to minor operations and maintenance expenditures. Regarding the Pennsylvania site, in March 2006, a federal district court approved three consent decrees between the U.S. and the PRPs, under which we and certain other PRPs, all of which are utilities, will perform the site remediation. The remediation costs are expected to be in the range of $11 million to $18 million, the majority of which are to be paid by the non-utility site owners. After evaluating the impact of these actions, we have reduced our current reserve from $2 million to less than $1 million to meet our potential obligations at these two sites. We generally seek to recover our costs associated with environmental remediation from third-party insurers. At December 31, 2006, no pending or possible insurance claims were recognized as an asset or offset against obligations.

Nuclear Operations

NUCLEAR DECOMMISSIONING—MINIMUM FINANCIAL ASSURANCE

The Nuclear Regulatory Commission (NRC) requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Our 2006 NRC minimum financial assurance amount, aggregated for our nuclear units, was $1.3 billion and has been satisfied by a combination of the funds being collected and deposited in the trusts and the real annual rate of return growth of the funds allowed by the NRC.

NUCLEAR INSURANCE

The Price-Anderson Act provides the public up to $10.8 billion of 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 adjustment 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 $100.6 million for each of our four licensed reactors, not to exceed $15 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, individually) 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 $50 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.

Old Dominion Electric Cooperative (ODEC), a part owner of North Anna Power Station, 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, with Dominion, filed a lawsuit in the U.S. Court of Federal Claims against the DOE in connection with its failure to commence accepting spent nuclear fuel. Trial is scheduled for March 2008. 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 electric generating facility. In 1989, we entered into a coal transportation agreement with Norfolk Southern Railway Company (Norfolk Southern) for the delivery of coal to the facility. The agreement provided for a base rate price adjustment based upon a published index. Norfolk Southern claimed in October 2003 that an incorrect reference index was used to adjust the base transportation rate. In November 2003, we and ODEC filed suit against Norfolk Southern seeking to clarify the price escalation provisions of the transportation agreement. The trial court has ruled in Norfolk Southern's favor by concluding that the agreement specifies the higher rate adjustment factor which Norfolk Southern claims should have been applied in the past to adjust the base rate and which will be applied in the future. 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 under the higher rate adjustment factor 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 calculate future invoices using the higher rate adjustment factor as if it had been applied from the inception of the agreement. The cumulative amount of the adjustment as of the time the court entered its order was approximately $50 million plus interest, of which our share would be one half. We and ODEC have filed a notice of appeal to the Virginia Supreme Court and have posted security to suspend execution of the judgment during the appeal. We believe the court's interpretation of the transportation agreement and its ruling on other issues in the case are legally incorrect. No liability has been recorded in our Consolidated Financial Statements related to this matter.

Guarantees and Surety Bonds

As of December 31, 2006, we had issued $6 million of guarantees primarily to support commodity transactions of subsidiaries. We had also purchased $68 million of surety bonds for various purposes, including the posting of security to suspend execution of the judgment during the appeal of the Norfolk Southern matter, as discussed in *Litigation*, and 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, 2006, 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.

Stranded Costs

Stranded costs are generation-related costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market. At December 31, 2006, our exposure to potential stranded costs included long-term power purchase contracts that could ultimately be determined to be above market prices; generating plants that could possibly become uneconomical in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits. We believe capped electric retail rates will provide an opportunity to recover our potential stranded costs, depending on market prices of electricity and other factors. Recovery of our potential stranded costs remains subject to numerous risks even in the capped-rate environment. These risks include, among others, exposure to long-term power purchase commitment losses, future environmental compliance requirements, changes in certain tax laws, nuclear decommissioning costs, increased fuel costs, inflation, increased capital costs and recovery of certain other items.

The Virginia Electric Utility Restructuring Act was enacted in 1999 (1999 Virginia Restructuring Act) and established a plan to restructure the electric utility industry in Virginia. Under the 1999 Virginia Restructuring Act, the generation portion of our Virginia jurisdictional operations is no longer subject to cost-based regulation. The legislation's deregulation of generation was an event that required us to discontinue the application of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, to the Virginia jurisdictional portion of our generation operations in 1999. The 1999 Virginia Restructuring Act permits wires charges to be collected by utilities until July 1, 2007. Our wires charges are set at zero in 2007 for all rate classes, and as such, Virginia customers will not pay the fee if they switch from us to a competitive service provider.

Virginia Fuel Expenses

In May 2006, Virginia law was amended to modify the way our Virginia jurisdictional fuel factor is set during the three and one-half year period beginning July 1, 2007. The bill became law effective July 1, 2006 and:

- Allows annual fuel rate adjustments for three twelve-month periods beginning July 1, 2007 and one six-month period beginning July 1, 2010 (unless capped rates are terminated earlier under the 1999 Virginia Restructuring Act);
- Allows an adjustment at the end of each of the twelve-month periods to account for differences between projections and actual recovery of fuel costs during the prior twelve months; and
- Authorizes the Virginia Commission to defer up to 40% of any fuel factor increase approved for the first twelve-month period, with recovery of the deferred amount over the two and one-half year period beginning July 1, 2008 (under prior law, such a deferral was not possible).

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen in 2004, which has resulted in our fuel expenses being significantly in excess of our rate recovery. We expect that fuel expenses will continue to exceed rate recovery until our fuel factor is adjusted in July 2007. While the 2006 amendments do not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor is adjusted, the risk of under-recovery of prudently incurred fuel costs until July 1, 2010 is greatly diminished.

2007 Virginia Restructuring Act Amendments

In February 2007, both houses of the Virginia General Assembly passed identical bills that would significantly change electricity restructuring in Virginia. The bills would end capped rates two years early, on December 31, 2008. After capped rates end, retail choice would be eliminated for all but individual retail customers with a demand of more than 5-Mw and a limited number of non-residential retail customers whose aggregated load would exceed 5-Mw. Also after the end of capped rates, the Virginia Commis -

sion would set the base rates of investor-owned electric utilities under a modified cost-of-service model. Among other features, the currently proposed model would provide for the Virginia Commission to:

- Initiate a base rate case for each utility during the first six months of 2009, as a result of which the Virginia Commission:
  - establishes a return on equity (ROE) no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations on earnings and rate adjustments;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return, if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may reduce rates or, alternatively, order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE; and
  - may authorize performance incentives if appropriate.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - establishes an ROE no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations on earnings and rate adjustments; however, if the Virginia Commission finds that such ROE limit at that time exceeds the ROE set at the time of the initial base rate case in 2009 by more than the percentage increase in the CPI in the interim, it may reduce that lower ROE limit to a level that increases the initial ROE by only as much as the change in the CPI;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE, and reduce rates if the utility is found to have such excess earnings during two consecutive biennial review periods; and
  - may authorize performance incentives if appropriate.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service, energy efficiency and conservation programs, and renewable energy programs; and
- Authorize an enhanced ROE as a financial incentive for construction of major baseload generation projects and for renewable energy portfolio standard programs.

The bills would also continue statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter. However, our fuel factor increase as of July 1, 2007 would be limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of that date, and the remainder would be deferred and collected over three years, as follows:

- in calendar year 2008, the deferral portion collected is limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of January 1, 2008;
- in calendar year 2009, the deferral portion collected is limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of January 1, 2009; and
- the remainder of the deferral balance, if any, would be collected in the fuel factor in calendar year 2010.

The Governor has until March 26, 2007 to sign, propose amendments to, or veto the bills. With the Governor's signature, the bills would become law effective July 1, 2007. At this time, we cannot predict the outcome of these legislative proposals.

NOTE 22. 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. Fair values have been determined using available market information and valuation methodologies considered appropriate by management. The financial instruments' carrying amounts and fair values are as follows:

At December 31,	2006		2005	
	Carrying Amount	Estimated Fair Value(1)	Carrying Amount	Estimated Fair Value(1)
(millions)				
Long-term debt(2)	$4,254	$ 4,236	$3,874	$ 3,887
Junior subordinated notes payable to affiliated trust	412	422	412	423
Note payable to Dominion	220	236	220	230

(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.

NOTE 23. 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, 2006 provision for credit losses, 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.

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 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, 2006, our gross credit exposure totaled $51 million. Of this amount, 93% related to a single counterparty; however, the entire balance is with investment grade entities. We held no collateral for these transactions at December 31, 2006.

NOTE 24. RELATED-PARTY TRANSACTIONS

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

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 the purchases and sales of natural gas. We designate the majority of these contracts as cash flow hedges for accounting purposes.

Dominion Resources Services, Inc. (Dominion Services) provides accounting, legal and certain administrative and technical services to us. We provide certain services to affiliates, including charges for facilities and equipment usage.

At December 31, 2005 we transferred VPEM to Dominion in exchange for a $633 million contribution of capital. In doing so, we are no longer involved in facilitating Dominion's enterprise risk management by entering into certain financial derivative commodity contracts with affiliates. During 2006, VPEM continued to provide fuel management services to us by acting as an agent for one of our other indirect wholly-owned subsidiaries. In December 2006, we entered into an agreement with VPEM which enables us to directly transact with VPEM for the purchase and sale of fuel and the transportation of fuel to our facilities. This agreement has been approved by the Virginia Commission and the North Carolina Commission and became effective January 2007.

The significant transactions with Dominion Services and other affiliates are detailed below:

Year Ended December 31,	**2006**	2005	2004
(millions)			
Commodity purchases from affiliates	**$234**	$364	$227
Services provided by affiliates	**311**	292	264
Services provided to affiliates	**26**	26	25

At December 31, 2006, our Consolidated Balance Sheet includes derivative liabilities with affiliates of $2 million. There were no derivative liabilities with affiliates at December 31, 2005. Unrealized gains or losses, representing the effective portion of the changes in fair value of those derivative contracts that had been designated as cash flow hedges, are included in AOCI in our Consolidated Balance Sheets.

We lease an office building from Dominion under an agreement that expires in 2008. The lease agreement is accounted for as a capital lease, with capitalized cost of the property under the lease, net of accumulated amortization, of approximately $3 million and $5 million at December 31, 2006 and 2005, respectively. The rental payments for this lease were $3 million each in 2006, 2005 and 2004.

We have borrowed funds from Dominion under both short-term and long-term borrowing arrangements. At December 31, 2006 and 2005, our nonregulated subsidiaries had outstanding borrowings, net of repayments, under the Dominion money pool of $140 million and $12 million, respectively. At December 31, 2006 and 2005, our borrowings from Dominion under a long- term note totaled $220 million. There were no short-term demand note borrowings at December 31, 2006 and 2005. We incurred interest charges related to our borrowings from Dominion of $10 million, $9 million and $6 million in 2006, 2005 and 2004, respectively.

In 2004, as approved by the Virginia Commission, Dominion made an equity investment in the Company through the purchase of our common stock. We issued 20,115 shares of our common stock to Dominion for cash consideration of $500 million. We used the proceeds in part to pay down our $345 million short-term demand note from Dominion. Also, in 2004, we recorded $11 million of other paid-in capital in connection with a reduction in amounts payable to Dominion.

Other Related-Party Transactions

Upon adoption of FIN 46R for our interests in special purpose entities on December 31, 2003, we ceased to consolidate the Virginia Power Capital Trust II, a finance subsidiary of the Company. The junior subordinated notes issued by us and held by the trust are reported as long-term debt. We reported $30 million, $30 million and $31 million of interest expense on the junior subordinated notes payable to affiliated trust in 2006, 2005 and 2004, respectively.

NOTE 25. OPERATING SEGMENTS

We are organized primarily on the basis of products and services sold in the United States. 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 Delivery, Energy and Generation segments. We manage our operations through the following segments:

Delivery includes our regulated electric distribution and customer service businesses. The Delivery segment is subject to cost-of-service rate regulation and accordingly, applies SFAS No. 71.

Energy includes our regulated electric transmission operations, which are subject to cost-of-service rate regulation and accordingly, applies SFAS No. 71.

Generation includes our portfolio of electric generating facilities, power purchase agreements and our energy supply operations.

Corporate includes our corporate and other functions. 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 have been excluded from the profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments, including the discontinued operations of VPEM prior to its transfer to Dominion.

In 2006, the Corporate segment includes $12 million of net expenses attributable to our Generation segment. The net expenses in 2006 related to the following:

- 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; and
- A $7 million ($4 million after-tax) charge resulting from the write-off of certain assets no longer in use at one of our electric generating facilities.

In 2005, the Corporate segment included $58 million of net expenses attributable to our operating segments. The net expenses in 2005 primarily related to the impact of the following:

- A $77 million ($47 million after-tax) charge resulting from the termination of a long-term power purchase agreement attributable to Generation;
- A $13 million ($8 million after-tax) charge related to the sale of our interest in a long-term power tolling contract attributable to Generation; and
- A $6 million ($4 million after-tax) charge for the cumulative effect of an accounting change, as a result of the adoption of FIN 47.

In 2004, the Corporate segment included $155 million of net expenses attributable to our operating segments. The net expenses in 2004 primarily related to the impact of the following:

- A $184 million ($112 million after-tax) charge related to our interest in a long-term power tolling contract that was divested in 2005, attributable to Generation;
- A $71 million ($43 million after-tax) charge resulting from the termination of three long-term power purchase agreements, attributable to Generation; and
- A $12 million ($7 million after-tax) charge related to an agreement to settle a class action lawsuit involving a dispute over our rights to lease fiber-optic cable along a portion of our electric transmission corridor, attributable to Energy; partially offset by
- An $18 million ($11 million after-tax) benefit from the reduction of expenses accrued in 2003 associated with Hurricane Isabel restoration activities, attributable to Delivery.

The following table presents segment information pertaining to our operations:

Year Ended December 31,	Delivery	Energy	Generation	Corporate	Adjustments & Eliminations	Consolidated Total
(millions)						
2006						
Operating revenue	$ 1,182	$ 214	$ 4,202	$ 5	$ —	$ 5,603
Depreciation and amortization	259	34	225	18	—	536
Interest and related charges	107	22	173	—	(6)	296
Income tax expense (benefit)	170	42	80	(8)	—	284
Net income (loss)	270	69	151	(12)	—	478
Capital expenditures	395	129	523	—	—	1,047
Total assets	5,453	1,595	9,250	—	(615)	15,683
2005						
Operating revenue	$ 1,183	$ 213	$ 4,309	$ 8	$ (1)	$ 5,712
Depreciation and amortization	246	33	227	21	—	527
Interest and related charges	117	32	181	1	(9)	322
Income tax expense (benefit)	179	39	86	(35)	—	269
Loss from discontinued operations, net of tax	—	—	—	(471)	—	(471)
Cumulative effect of change in accounting principle, net of tax	—	—	—	(4)	—	(4)
Net income (loss)	298	66	175	(529)	—	10
Capital expenditures	390	131	331	—	—	852
Total assets	5,374	1,469	9,308	—	(702)	15,449
2004						
Operating revenue	$ 1,142	$ 213	$ 4,007	$ 10	$ (1)	$ 5,371
Depreciation and amortization	234	34	206	22	—	496
Interest and related charges	99	24	128	1	(3)	249
Income tax expense (benefit)	173	46	220	(100)	—	339
Loss from discontinued operations, net of tax	—	—	—	(159)	—	(159)
Net income (loss)	288	76	380	(313)	—	431

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, CONTINUED

NOTE 26. QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of our quarterly results of operations for the years ended December 31, 2006 and 2005 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.

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2006					
Operating revenue	**$ 1,333**	**$ 1,323**	**$ 1,690**	**$ 1,257**	**$5,603**
Income from operations	**206**	**185**	**385**	**207**	**983**
Net income	**97**	**86**	**209**	**86**	**478**
Balance available for common stock	**93**	**82**	**205**	**82**	**462**
2005					
Operating revenue	$ 1,358	$ 1,285	$ 1,774	$ 1,295	$5,712
Income from operations	240	262	328	176	1,006
Income from continuing operations before cumulative effect of change in accounting principle	115	124	177	69	485
Income (loss) from discontinued operations, net of tax	(93)	(67)	(360)	49	(471)
Net income (loss)	22	57	(183)	114	10
Balance available for common stock	18	53	(187)	110	(6)

Our 2005 results include the impact of the following significant item:

- First quarter results include a $47 million net after-tax charge in connection with the termination of a long-term power purchase agreement.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Senior management, including our Chief Executive Officer and Chief Financial Officer, 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 Chief Executive Officer and Chief Financial Officer 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.

In accordance with FIN 46R, we have included in our Consolidated Financial Statements a VIE through which we have financed and leased a power generation project. Our Consolidated Balance Sheet as of December 31, 2006 reflects $337 million of net property, plant and equipment and deferred charges and $370 million of related debt attributable to the VIE. As this VIE is owned by unrelated parties, we do not have the authority to dictate or modify, and therefore cannot assess, the disclosure controls and procedures or internal control over financial reporting in place at this entity.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

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

Name and Age	Principal Occupation for Last Five Years and Directorships in Public Corporations	Year First Elected as Directors
Thomas F. Farrell, II (52)	Chairman of the Board of Directors and Chief Executive Officer (CEO) of VP from February 2006 to date; President and CEO of Dominion Resources, Inc. (DRI) from January 2006 to date; Director of DRI from March 2005 to date; Chairman of the Board of Directors, President and CEO of Consolidated Natural Gas Company (CNG) from January 2006 to date; President and Chief Operating Officer (COO) of DRI from January 2004 to December 2005; President and COO of CNG from January 2004 to December 2005; Executive Vice President of DRI from March 1999 to December 2003; President and CEO of VP from December 2002 to December 2003; Executive Vice President of CNG from January 2000 to December 2003; CEO of VP from May 1999 to December 2002.	1999
Thomas N. Chewning (61)	Executive Vice President and Chief Financial Officer (CFO) of VP from February 2006 to date; Executive Vice President and CFO of DRI from May 1999 to date; Executive Vice President and CFO of CNG from January 2000 to date; Director of CNG from December 2002 to date.	1999

Audit Committee Financial Experts

We are a wholly-owned subsidiary of DRI. As permitted by Securities and Exchange Commission (SEC) rules, our Board of Directors serves as our Company's Audit Committee and is comprised entirely of executive officers of the Company. Our Board of Directors has determined that Thomas F. Farrell, II and Thomas N. Chewning are "audit committee financial experts" as defined by the SEC and, as executive officers of the Company, are not deemed independent.

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

Name and Age	Business Experience Past Five Years
Thomas F. Farrell, II (52)	Chairman of the Board of Directors and CEO of VP from February 2006 to date; President and CEO of DRI from January 2006 to date; Chairman of the Board of Directors, President and CEO of CNG from January 2006 to date; Director of DRI from March 2005 to date; President and COO of DRI from January 2004 to December 2005; President and COO of CNG from January 2004 to December 2005; Executive Vice President of DRI from March 1999 to December 2003; President and CEO of VP from December 2002 to December 2003; Executive Vice President of CNG from January 2000 to December 2003; CEO of VP from May 1999 to December 2002.
Thomas N. Chewning (61)	Executive Vice President and CFO of VP from February 2006 to date; Executive Vice President and CFO of DRI from May 1999 to date; Executive Vice President and CFO of CNG from January 2000 to date.
Jay L. Johnson (60)	President and COO—Delivery of VP from February 2006 to date; Executive Vice President of DRI from January 2004 to date; President and CEO of VP from December 2002 to January 2006; Executive Vice President of CNG from December 2002 to date; Senior Vice President, Business Excellence, Dominion Energy, Inc. (DEI) from September 2000 to December 2002.
Paul D. Koonce (47)	Executive Vice President of DRI from April 2006 to date; President and COO—Energy of VP from February 2006 to date; CEO—Energy of VP from January 2004 to January 2006; CEO—Transmission of VP from January 2003 to December 2003; Senior Vice President—Portfolio Management of VP from January 2000 to December 2002.
Mark F. McGettrick (49)	Executive Vice President of DRI from April 2006 to date; President and COO—Generation of VP from February 2006 to date; President and CEO—Generation of VP from January 2003 to January 2006; Senior Vice President and Chief Administrative Officer of DRI from January 2002 to December 2002; President of Dominion Resources Services, Inc. (DRS) from October 2002 to January 2003.
David A. Christian (52)	Senior Vice President—Nuclear Operations and Chief Nuclear Officer from April 2000 to date.
Steven A. Rogers (45)	Senior Vice President and Chief Accounting Officer of VP, DRI and CNG from January 2007 to date; Senior Vice President (Principal Accounting Officer) (PAO) of VP from April 2006 to December 2006; Senior Vice President and Controller of DRI and CNG from April 2006 to December 2006; Vice President, Controller and PAO of DRI and CNG and Vice President and PAO of VP from June 2000 to April 2006.

Any service listed for DRI, DEI, 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.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

We are a wholly-owned subsidiary of Dominion. Our Board is comprised of Messrs. Farrell and Chewning, who are executive officers of the Company and are not independent. 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 has retained the consulting firm of Pearl Meyer & Partners (PMP) to advise them on compensation matters. Our Board approves all compensation paid to VP's executive officers based on Dominion's CGN Committee's recommendations. Neither of our directors, who are officers of the Company and Dominion, receive any compensation for the services they provide as directors. Dominion's CGN Committee effectively administers one compensation program for all of Dominion.

Executive Compensation Philosophy – The Objectives of Dominion's Program

Dominion's executive compensation program is designed to attract, motivate and retain a superior management team, while ensuring that annual and long-term incentive programs align management's financial success with that of Dominion's shareholders. Dominion's management and Board of Directors, through the oversight of the CGN Committee, believe in putting a substantial portion of our senior executives' compensation at risk based on performance goals established by the CGN Committee. While Dominion benchmarks and sets general compensation levels relative to its peer group of companies (detailed below) and market data in general, it administers the program to meet the needs and requirements of Dominion. This takes into consideration internal equity, experience, scope of responsibility and other concerns. Market data is used as a "reality check" in evaluating our compensation decisions for our senior executives.

Our Process

Each year, the executive compensation program is comprehensively assessed and analyzed. The review process includes, but is not limited to, the following steps:

- A peer group of companies is identified and Dominion is compared with these peer companies based on a number of different financial and stock performance metrics for a number of different measurement periods;
- The CGN Committee reviews the performance of the CEO and other senior officers, including the CEO's assessment of the performance of other key officers, and his views on succession and retention issues (our Company and Dominion have the same CEO and CFO);
- The current annual compensation of senior management, and long-term compensation grants made over the past few years are reviewed;
- The appropriate performance metrics and attributes of annual and long-term programs for the next year are considered and discussed;
- The entirety of our compensation program is considered, including periodic reviews of specific benefits and perquisites;
- Base pay, annual incentive pay, long-term pay and total compensation for individual officers are benchmarked against survey data using appropriate job matches and comparable asset and revenue size. The survey data is based on a number of purchased surveys from Mercer HR Consulting, Towers Perrin and other organizations, including industry specific surveys whenever possible. The industry specific surveys provide information on positions at companies of similar size or revenue scope, or general industry data on positions for which we may compete;
- For top officers, if peer group compensation is available for their position, Dominion uses a blend of survey and peer compensation for comparison, as there is competition not only in our own market, but nationally and across industries, for talent;
- The compensation practices of our peer companies are reviewed, including their practices with respect to equity and other grants, benefits and perquisites;
- The compensation of the management team from the standpoint of internal equity, complexity of the job, scope of responsibility and other factors is assessed; and
- Specific market-based conditions and other circumstances for certain executives and competitive business groups are considered.

Dominion's management has the following involvement with the executive compensation process:

- Dominion's Financial Planning group identifies companies for inclusion in the peer group based on our industry and the companies used by Dominion analysts and external analysts for comparison purposes. Both Dominion's CFO and the CGN Committee's independent compensation consultant, a managing director of PMP, review and comment on the proposed group before it is submitted to the CGN Committee for approval;
- Dominion's CEO and CFO are both involved in establishing and recommending to the CGN Committee financial goals for the incentive programs based on management's operational goals and strategic plans; and
- Dominion's CEO reviews recommendations from Dominion's director of executive compensation and PMP regarding salaries, annual and long-term incentive targets, and plan amendments and design before recommendations are made to the CGN Committee. While he reviews and makes recommendations for officers, Dominion's CEO does not make any recommendations or review proposals with regard to his own compensation, with only the CGN Committee having the authority to approve compensation for the senior executives. Also, our independent compensation consultant meets with the CGN Committee, without management present, to review her recommendations. Dominion's CEO and CFO are also involved in making recommendations about the timing and frequency of long-term programs, special arrangements to

address specific concerns and the elimination or modification of certain benefits.

- Our Board reviews information provided by and considers for approval compensation matters recommended by the CGN Committee.

The Peer Group and Peer Group Comparisons

Dominion's peer group is generally consistent from year to year, with merger and acquisition activity being the primary reason for any changes. The 2006 peer group for compensation-setting purposes consisted of a diversified group of ten energy companies: American Electric Power Company, Inc.; Constellation Energy Group, Inc.; Duke Energy Corporation; Entergy Corporation; Exelon Corporation; First Energy Corporation; FPL Group, Inc.; Progress Energy, Inc.; Southern Company and TXU Corp.

The CGN Committee, PMP and Dominion's executive compensation department use the peer company data to (i) compare Dominion's stock and financial performance against these peers using a number of different metrics and time periods; (ii) analyze compensation practices within the industry; and (iii) benchmark other benefits such as Employment Continuity Agreements and the use of long-term equity vehicles.

Elements of Dominion's Compensation Program

Our executive compensation program consists of three basic components:

- Base Salary
- Annual Incentives
- Long-Term Incentives

BASE SALARY

Base salary compensates officers, along with the rest of the workforce, for committing significant time to working on the Company's behalf. In considering annual salary increases, the following factors are assessed: (i) the competitive labor market; (ii) changes in an officer's scope of responsibility, including promotions; and (iii) individual performance, special skills, experience and other relevant considerations.

While the base salary component of the compensation program generally is targeted at or slightly above market median, the primary goal is compensating executives at a level that best achieves Dominion's compensation philosophy and addresses internal equity issues. This results in actual pay for some positions that may be higher or lower than a stated target. Dominion has found that peer group and survey results for particular positions can vary greatly from year to year, and considers market trends for certain positions over a period of years rather than a one-year snapshot in setting compensation for those positions.

For 2006 base compensation, all officers received a base salary adjustment of at least 4%. Some officers received salary adjustments in excess of 4% for one of the following reasons: (i) increase or other change in job responsibility; (ii) specific market-based reasons; (iii) exceptional performance; (iv) unique retention or job competitiveness reasons; and/or (v) internal pay equity. Mr. Farrell received a 29% increase in base salary in 2006, when he assumed the duties of CEO of Dominion. Even with this increase, his base salary and targeted total cash compensation were below the median for his peers. The CGN Committee determined to bring his base salary to the market median over the course of a few years, based on his achievements and performance in office. The remaining named executive officers received the following 2006 base salary increases: Mr. Chewning – 13.6%; Mr. McGettrick – 26.5%; Mr. Johnson – 10%; and Mr. Christian – 12%. Mr. Chewning's increase resulted in his base pay being slightly above market median in recognition of his experience and superior job performance, and the complexity and scope of his responsibilities. Messrs. McGettrick and Johnson's base salaries continued to lag behind the market median based on the increasing size of their business units, the effects of several years with no or below market increases in base salary. Messrs. McGettrick and Johnson's increases were aimed at bringing their base salaries closer to market median. Messrs. McGettrick and Christian's increases were also due to the competitive nature of their positions and to reward excellent performance.

ANNUAL AND LONG-TERM INCENTIVE PROGRAMS

Annual and long-term incentive programs continue to play a critical role in Dominion's compensation practices and our philosophy of aligning the interests of officers with those of Dominion's shareholders while rewarding performance. The annual incentive program is a cash-based program focused on short-term goal accomplishments. The long-term incentive program is weighted equally between a retention component (restricted stock) and a performance component (cash-based performance grant).

Performance-Based Compensation. The performance-based components of Dominion's incentive program (annual incentive plan and the cash performance grants of our long-term program) motivate and encourage officers and employees to achieve operational excellence that will benefit Dominion's shareholders. Dominion uses a blend of goals focused on Dominion's financial achievements overall, specific business unit goals and individual goals. These components allow Dominion to encourage and reward officers and employees for achieving financial goals, as well as operating and stewardship goals such as safety and individual power plant performance.

Annual and long-term incentives are an industry standard and a best practice to motivate employees to achieve performance goals for a portion of their compensation. Performance-based compensation is a large part of executives' compensation, with senior officers having the most compensation at risk based on performance. This correlates with the influence and responsibility each level of management has for delivering financial results.

For our CEO, Mr. Farrell, just over 50% of his targeted total compensation (annual and long term) is at risk and depends on the achievement of performance goals. For the other named executive officers, targeted compensation at risk ranged from 49% to 44%, and for a typical vice president, the percentage of targeted compensation at risk is approximately 38%. This compares to an average of approximately 11% of total pay at risk for non-officer employees. This structure ensures that if performance goals are not achieved, the officers have compensation that could be significantly lower than market median depending on the extent goals are missed. If performance goals are exceeded, officers will receive compensation that is close to or at the market 75th percentile, depending on the extent that goals are exceeded. Additionally, a substantial portion of each officer's total compensation is tied to the performance of Dominion's stock through their restricted stock grants, ranging from 18% of targeted total compensation for a typical vice president up to 37% for Mr. Farrell. For Mr. Farrell, this results in almost 90% of his total direct compensation having a performance component.

Dominion's Board may seek to recover performance-based compensation paid to officers who are found to be personally responsible for fraud, negligence or intentional misconduct that causes a restatement of financial results filed with the SEC.

Annual Incentive Plan. The Annual Incentive Plan focuses on short-term goals, and for the CEO, comprised more than half of his annual cash compensation for 2006. With the introduction of cash-based performance grants in 2006 as outlined below, the CEO and each eligible officer may receive a higher percentage of their total 2007 compensation (annual and long-term) earned in cash, based on goal accomplishment.

Under the Annual Incentive Plan, the CGN Committee establishes "target awards" for each executive. These target awards are expressed as a percentage of the individual executive's base salary (for example, 50% x base salary). The target award is the amount of cash that will be paid, at year-end, if the plan is fully funded and the executive achieves 100% of the goals established at the beginning of the year. Under the Annual Incentive Plan, if goals are achieved or exceeded, the executive's total cash compensation for the year is targeted to be at or slightly above market median. If the goals are not achieved, the executive's total cash compensation may be significantly lower than market median, depending on the extent to which goals were not achieved. For 2006, Mr. Farrell's annual incentive target was 110% of his base salary, consistent with our intent of having a substantial portion of his compensation at risk. For 2006, Mr. Chewning's target was 90%, Messrs. McGettrick and Johnson's target was 80%, and Mr. Christian's target was 70%.

The 2006 Annual Incentive Plan was funded based on goals established and approved by the CGN Committee at the beginning of 2006. For the 2006 Annual Incentive Plan, the threshold consolidated earnings goal for any payout under the plan was reported operating earnings for Dominion of $5.05 per share, with full funding at reported operating earnings of $5.15 per share. Additionally, if Dominion's reported operating earnings exceeded $5.15 per share, then for every one cent reported over $5.15 per share, 3% in additional funding would be applied to the 2006 Annual Incentive Plan, up to a maximum of 200% funding. This results in the Company and employees sharing equally in earnings above the $5.15 per share goal until the 200% maximum funding level is achieved.

To access the funded bonus pool, each executive must meet certain goals, including consolidated and business unit financial goals as well as operating, stewardship and Six Sigma targets. The consolidated earnings goal is designed to drive employee behavior and performance to ensure that shareholders receive an appropriate return on their investment in Dominion.

The business unit financial goals are set based on the levels necessary to achieve the consolidated earnings goal for Dominion. Also, individual business unit goals provide line-of-sight targets for officers and employees, and facilitate financial and business planning at the business unit level.

The operating and stewardship goals may not be financial, and can be customized for a business unit or individual. The accomplishment of these goals often supports the business unit financial goals. The most common operating and stewardship goals have objectives in the following areas: safety; reliability; expenditures and production; forced outages; and service level requirements.

Finally, Six Sigma goals support Dominion's mission to continue to use Six Sigma to increase productivity, improve service reliability, reduce costs and enhance customer service while bringing the benefits of these improvements to the bottom line.

Each executive's goals are weighted according to his or her responsibilities. Payout under the plan is determined by multiplying the employee's target bonus by the percentage the plan is funded (e.g., 100%) by the percentage that the employee's own personal goal package is achieved (e.g., 90%).

The goal weightings for bonuses under the 2006 Annual Incentive Plan for Dominion's named executive officers (which includes Messrs. Farrell, Chewning, McGettrick and Johnson) and all other officers (which includes Mr. Christian) were as follows:

	Consolidated Financial Goal	Business Unit Financial Goals	Operating/ Stewardship	Six Sigma
Dominion's named executive officers	100%	0%	0%	0%
Other officers	25%	50%	15%	10%

For Messrs. Farrell, Chewning, McGettrick and Johnson, bonuses were based solely on the consolidated earnings goal, with the CGN Committee having discretion to reduce final payouts to the extent appropriate, based on any goal accomplishment that was less than 100% for the corporate-wide Six Sigma goal, and for Messrs. McGettrick, Johnson and Christian, any goal accomplishment that was less than 100% for their business unit financial goals or their own personal operating/stewardship goals. The reductions could be as much as the percentages set forth in the table above for each category for other officers. Due to the broad scope of their duties, Messrs. Farrell and Chewning did not have operating and stewardship goals, as these goals tend to be business-unit specific.

Dominion compared actual financial performance for 2006 with the consolidated and business unit earnings goals. Dominion achieved operating earnings of $5.17 per share in 2006 before any additional funding under our plan. Taking into account the funding formula described above, the 2006 Annual Incentive Plan was funded at the 103% level, with additional 3% funding available to cover any upside from the Six Sigma stretch goals described above. Dominion reported $5.16 per share in operating earnings as a result of funding these additions, with shareholders and employees each receiving one cent each of the operating earnings over $5.15 per share.

The Six Sigma goal for 2006 was a corporate-wide positive financial impact of $100 million, with a stretch goal of $150 million, which would result in an increase of 4% in each employee's payout score if the stretch goal were achieved. Dominion as a whole and each business unit exceeded their Six Sigma stretch goal, with corporate-wide savings of $224 million achieved in 2006. This resulted in all employees, except for Dominion's named executive officers (which includes Messrs. Farrell, Chewning, McGettrick and Johnson), receiving an additional 4% to their pay-out score for determining 2006 payouts, with a total possible payout of 107% of their target bonus. Dominion's named executive officers received 106% plan funding because their bonuses were based on consolidated earnings goals only, including the earnings kicker; however, their goal score was capped at 100%. Actual amounts earned under the 2006 Annual Incentive Plan by each of the Company's named executive officers are set forth in the Summary Compensation Table under the heading "Non-Equity Incentive Plan Compensation".

The Long-Term Incentive Program. For 2006, Dominion transitioned its long-term program from retention-based restricted stock, with alignment to its shareholders, to a long-term program that is both (i) aligned with the long-term interests of its shareholders through restricted stock grants and (ii) designed to put a substantial portion of the long-term compensation at risk based on the achievement of performance measures with the introduction of cash performance grants. Grants are typically made on or before April 1 of each year, and Dominion does not time the grant dates based on the release of material information or expectations of stock price changes. Newly promoted officers receive pro-rated grants for the current year's program based on the fair market value of the stock as of their date of employment or election to office.

Dominion has not issued stock options since 2002, although options remain outstanding from prior programs and are reported in the Outstanding Equity Awards at Fiscal Year End table on page 58, with options exercised in 2006 disclosed in the Option Exercises and Stock Vested table on page 59.

While the CGN Committee reviews prior grants to the CEO before approving new long-term grants, the determination of the appropriate grant for the CEO and other senior executives in any given year is based on the results of the process described above for the executive compensation program. Dominion does not "deduct" prior compensation paid to executives from the compensation being considered for the current year. Similarly, if a newer executive does not have prior grants outstanding due to his or her short tenure, Dominion does not increase the compensation paid to the executive due to a lack of outstanding grants from prior years.

Performance Grants. For 2006, Dominion transitioned to a long-term incentive program that is 50% performance-contingent, payable in cash rather than stock. These grants were made on April 1, 2006 and are "at-risk" based on the achievement of the two goals discussed below. The reasons for shifting a portion of the program to cash were (i) the significant ownership of Dominion stock by executives and the high rate of compliance with our share ownership requirements; (ii) to provide a more immediate award following achievement of goals and (iii) improve the tax efficiency of awards as no shares need to be sold to pay taxes, and any net cash award could be used to pay taxes on vesting restricted stock awards. Officers who have not achieved their ownership targets are expected to hold vested restricted stock, net of shares used to cover taxes.

The 2006 cash-based performance grants have a two-year term, with two equally weighted goals: i) Dominion's total shareholder return (TSR) for the 21 month period ended December 31, 2007 relative to the TSR of a group of industry peers selected by the CGN Committee; and ii) return on invested capital (ROIC) for the two-year period ended December 31, 2007. For the performance grants which were awarded in April 2006, the 2006 peer group was adjusted and NiSource, Inc. and PPL Corporation added to the peer group, and Constellation Energy Group was excluded for this grant as it was a merger candidate at that time. The grants are 100% performance-based with payouts ranging from 0-200% of target. The goals for the 2006 grant, scoring for such goals and possible payouts for the named executive officers are set forth in the Grants of Plan-Based Awards table on page 57.

*Restricted Stock Grants.*Officers also received restricted stock grants on April 1, 2006. The grants have cliff vesting at the end of the three-year restricted period. Restricted stock grants serve as a retention tool as they are forfeited upon voluntary termination and align the interests of officers with the interests of our shareholders.

The CGN Committee approved the 2006 long-term grants based on a stated dollar value for the award based on its earlier compensation review. Restricted stock was issued for 50% of the total long-term grant value, with ~~the number of shares issued~~ determined by using the fair value of Dominion's common stock the day before the date of grant (average of high and low stock price). Officers receive dividends on the restricted shares. The full grant date fair value of each named executive officer's 2006 restricted stock grant is disclosed in the Grants of Plan-Based Awards table on page 57.

*Vesting Terms for the 2006 Restricted Stock Grants and Performance Grants.*Both grants are forfeited in their entirety if the 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 the company. For the performance grants, the pro-rated payout is based on actual goal performance at the end of the performance cycle.

In the event of a Change in Control* at Dominion, the restricted shares have pro-rated vesting up to the change in control date, rewarding officers only for prior service. If the officers subsequently are terminated, or constructively terminate their employment, under the terms of the grant, any remaining unvested shares will vest at that point. For the cash performance grants, as any goals would likely be materially changed as a result of any Change in Control at Dominion, payout of these grants will accelerate and will be equal to the greater of the target grant amount or the payout that would be made based on the assumptions used for goal performance in Dominion's latest financial statements as of the day before the Change in Control occurred.

EMPLOYEE AND EXECUTIVE BENEFITS

Officers participate in many of the same employee benefit programs as other employees. The core benefit programs include two tax-qualified retirement plans, vacation program, medical coverage, dental coverage, vision coverage, life insurance, disability coverage, travel accident coverage, company-paid short-term disability and long-term disability coverage. There are other miscellaneous employee benefit programs, such as flexible spending accounts, health savings accounts, employee assistance programs, employee leave policies and other incidental programs available to employees generally. Tax-qualified retirement plans are a 401(k) plan and a defined benefit pension plan (Pension Plan). A matching contribution to each employee's 401(k) plan account of 50 cents for each dollar is made on the first 6% of compensation (up to IRS limits) if less than 20 years of service, and 67 cents for each dollar contributed on the first 6% of compensation (up to IRS limits) if the employee has at least 20 years of service. The amount of the company matching contributions under the 401(k) for the named executive officers ranged from $1,980 to $4,400. Amounts forgone due to IRS limits were paid to executives in cash and ranged from $3,312 to $8,192. All of these matching contribution amounts are shown in the All Other Compensation footnote to the Summary Compensation Table following this section. The defined benefit pension plan pays benefits under a formula that is explained in *Pension Benefits* and the change in pension value for 2006 is included in the Summary Compensation table on page 56.

* A Change in Control occurs 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.

Dominion also has two supplemental retirement plans for executives. The Benefit Restoration Plan makes up for certain limits related to Pension Plan benefits imposed by the Internal Revenue Code as more fully explained in *Pension Benefits* beginning on page 59. The Pension Plan and Benefit Restoration Plan pay benefits calculated on base salary. To accommodate changes in tax law, the Dominion Benefit Restoration Plan was frozen as of December 31, 2004 (Frozen BRP) and a New Benefit Restoration Plan was implemented effective January 1, 2005 (New BRP). There is no change in the total benefit provided as a result of this new plan.

The Executive Supplemental Retirement Plan provides an annual retirement benefit equal to 25% of a participant's final cash compensation (base salary plus target annual bonus) for a period of ten years or life as more fully explained in *Pension Benefits*. To accommodate changes in the tax law, the Executive Supplemental Retirement Plan was frozen as of December 31, 2004 (Frozen ESRP) and a New Executive Supplemental Retirement Plan was implemented effective January 1, 2005 (New ESRP). There is no change in the benefit provided as a result of this new plan.

Dominion maintains the Benefit Restoration Plan and the Supplemental Retirement Plan to provide a competitive level of retirement benefits to our executives. The Pension Plan and its related Benefit Restoration Plan provide a benefit that is calculated on base salary, credited age, credited service and a social security off-set. Because a more substantial portion of our executives' total compensation is paid as incentive compensation than for rank and file employees, the Pension Plan and Benefit Restoration Plan alone would not produce the same percentage of replacement income in retirement for executives as for rank and file employees. The Supplemental Retirement Plan is intended to partially make up for the limitation of these two plans due to their use of base salary only. The Supplemental Retirement Plan includes bonuses in its calculations, but does not include long- term incentive compensation. As a result, a significant portion of the potential compensation for our executives are excluded from calculation in any retirement plan benefit. The present value of accumulated benefits under these plans are disclosed in the Pension Benefits table on page 59.

Dominion also maintains a voluntary Executive Life Insurance Program for our executives. The plan provides for whole-life insurance policies to executives with a death benefit that is a multiple (one to three times) of each executive's base salary. This insurance is in addition to the term insurance that is provided as an employee benefit. The executive is the owner of the policy and the company will make premium payments to the later of 10 years or age 64. Executives are taxed on the value of the insurance provided by the company. The premiums for these policies are included in the All Other Compensation footnote to the Summary Compensation Table.

Perquisites. Dominion provides perquisites for executives that are considered reasonable by the CGN Committee and in line with market practice. In addition to incidental perquisites associated with maintaining an office, the following limited number of perquisites are offered to executives:

(1) An allowance of up to $9,500 a year for financial, estate and tax planning as well as for health and physical well being services. Dominion wants executives to be proactive with preventative healthcare and financial and estate planning and to ensure proper tax reporting of company-provided compensation.

(2) A company-leased vehicle, including the cost of insurance, gas and maintenance, up to an established lease-payment allowance (if the lease payment exceeds the allowance, the officer pays for excess amounts on the vehicle personally). Dominion offers this perquisite to be competitive with other comparable employers.

(3) Luncheon or other club memberships to provide a venue for business entertainment purposes. In 2007, Dominion is eliminating this perquisite.

(4) In limited circumstances, use of company aircraft for personal travel. Dominion's Board has required Mr. Farrell to use the aircraft for personal travel for reasons of security. Other executives' use of the aircraft is very limited, and usually related to (i) travel with the CEO or (ii) personal travel to accommodate business demands on the executives' schedule. Executives are taxed on all personal use of aircraft under IRS guidelines. Other than Mr. Farrell, the personal use of aircraft is not allowed when there is a company need for the aircraft. Use of the corporate aircraft saves our executives substantial time and allows better access to the executives for company purposes. Over 96% of the use of Dominion's company planes is for business purposes.

Tax Gross-Up. While these perquisites are generally taxable, the company provides a tax gross-up for the limited personal use of the company plane that does occur, spousal travel or expenses for business entertainment purposes and in a limited number of cases, clubs. As mentioned above, we will no longer pay for any clubs and therefore there will no longer be associated taxes or gross-ups on those clubs.

Other Agreements. In order to secure and retain the services and focus of key executives, Dominion has entered into agreements with each of our named executive officers to provide certain retirement benefits or other protections in certain circumstances, including Employment Continuity Agreements with each executive. The specific terms of these agreements are discussed in *Pension Benefits* and the tables under *Potential Payments upon Termination or Change in Control.*

Deductibility of Compensation

Under Section 162(m) of the Internal Revenue Code, Dominion may not deduct certain forms of compensation in excess of $1 million paid to its CEO or any of the four other most highly compensated executive officers. However, certain performance-based compensation is specifically exempt from the deduction limit.

It is Dominion's intent to provide competitive executive compensation while maximizing its tax deduction to the extent reasonable. The CGN Committee considers the Section 162(m) implications when approving certain plans and payouts. However, the CGN Committee reserves the right to approve, and in some cases has approved, non-deductible compensation if they believe it is in Dominion's best interest.

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SUMMARY COMPENSATION TABLE [1]

Name and Principal Position	Year	Salary	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 *Chief Executive Officer*	2006	$ 350,000	$ 686,742	$ 408,100	$ 915,719	$ 196,025	$ 2,556,586
Thomas N. Chewning *Executive Vice President and Chief Financial Officer*	2006	180,000	311,604	171,720	88,263	112,317	863,904
Mark F. McGettrick *President & COO—Generation*	2006	262,500	214,537	214,364	441,558	77,724	1,210,683
Jay L. Johnson *President & COO—Delivery*	2006	222,615	199,705	188,778	204,537	98,883	914,518
David A. Christian *Senior Vice President—Nuclear Operations and Chief Nuclear Officer*	2006	206,055	126,428	149,606	146,186	52,538	680,813

(1) 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 reflects only that portion which is allocated to the Company for the year presented.

(2) The amounts in this column reflect the compensation expense recognized in 2006 on all outstanding stock awards 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. The grant date fair value of each named executive officer's 2006 restricted stock grant is disclosed in the Grants of Plan-Based Awards table on page 57. See also the Outstanding Equity Awards at Fiscal Year-End table on page 58 for a listing of all outstanding equity awards as of December 31, 2006.

(3) The amounts in this column reflect the payout under Dominion's 2006 Annual Incentive Plan. All of the named executive officers except for Messrs. McGettrick and Christian received the full potential payout of their target awards, reflecting 106% funding of the 2006 Annual Incentive Plan and 100% payout for accomplishment of their goals. Messrs. McGettrick and Christian's payouts were reduced to an overall payout of 102% and 104%, respectively, of target due to less than 100% performance on safety and production cost goals. See Compensation Discussion and Analysis (CD&A) for additional information on the 2006 Annual Incentive Plan and the Grants of Plan Based Awards table for the range of each named executive officer's potential award under the 2006 Annual Incentive Plan (with this column reflecting the actual payout for each named executive officer).

(4) All amounts in this column are for the aggregate change in the actuarial present value of the named executive officer's accumulated benefit under our qualified pension plan and nonqualified executive retirement plans. There are no above-market earnings on non-qualified deferred compensation plans. These amounts 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, such as Mr. Farrell's promotion to Dominion's Chief Executive Officer as of January 1, 2006; (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 market factors.

(5) **All Other Compensation** amounts for 2006 are as follows

Name	Executive Perquisites (a)	Life Insurance Premiums	Tax Gross-up	Employee Savings 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	$ 29,352	$ 19,388	$ 15,017	$ 2,310	$ 8,190	$ 6,731	$ 115,037	$ 196,025
Thomas N. Chewning	19,297	25,693	4,320	1,980	4,560	0	56,467	112,317
Mark F. McGettrick	16,545	12,042	1,671	4,400	6,100	0	36,966	77,724
Jay L. Johnson	23,047	25,699	8,031	3,366	3,312	0	35,428	98,883
David A. Christian	13,579	8,976	0	3,960	4,282	0	21,741	52,538

(a) Unless noted, the amounts in this column for all officers are comprised of the following: personal use of a company vehicle; personal use (except for Messrs. McGettrick and Christian) of corporate aircraft; financial planning; health and wellness allowance; club fees (except for Mr. Christian); and home security system (Mr. Christian only). For Messrs. Farrell and Chewning, personal use of the corporate aircraft was $12,923 and $8,191 respectively. 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 96% of the use of the corporate aircraft is for business purposes. For Mr. Farrell, club fees were $9,294 which includes a one-time transfer fee for a corporate membership for his use while serving as CEO.

While some of the club fees are for personal memberships which may be used for business purposes, a majority of the fees reflected are for corporate memberships. Although we consider corporate club fees as a perquisite, a majority of the use of corporate club memberships is for business purposes. The aggregate incremental cost for club fees is based on actual costs incurred. As of January 1, 2007, the Company is eliminating the club perquisite program for executives, and they will be personally responsible for all dues.

In addition to these formal perquisite programs, executives may also receive some perquisites from time to time that have no incremental cost to the company. These would include (i) use of the company's travel department for making travel arrangements that may have a personal component to them; (ii) flights on the company plane when a seat is available for the spouse or other guest of an executive; (iii) an assigned parking spot; and (iv) occasional use of their administrative assistant or other company employees for assistance with charitable, community or personal matters.

(b) Paid under the terms of the Company's 401(k) plan.

(c) Represents payment of "lost" savings plan match due to IRS limits. This lost match was paid in cash to the named executive officers outside of the 401(k) plan.

GRANTS OF PLAN-BASED AWARDS [1]

Name	Grant Approval Date(2)	Grant Date(2)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards: Threshold	Target	Maximum	All Other Stock Awards: Number of Shares of	Grant Date Fair Value of Stock and Options Award(2)
Thomas F. Farrell, II							
2006 Annual Incentive Plan(3)			$ 0	$ 385,000	$ 770,000		
2006 Performance Grant(4)			$ 0	$ 1,050,000	$ 2,100,000		
2006 Restricted Stock Grant(4)	3/31/2006	4/1/2006				15,101	$ 1,050,004
Thomas N. Chewning							
2006 Annual Incentive Plan(3)			$ 0	$ 162,000	$ 324,000		
2006 Performance Grant(4)			$ 0	$ 300,000	$ 600,000		
2006 Restricted Stock Grant(4)	3/31/2006	4/1/2006				4,315	$ 300,015
Mark F. McGettrick							
2006 Annual Incentive Plan(3)			$ 0	$ 210,000	$ 420,000		
2006 Performance Grant(4)			$ 0	$ 300,000	$ 600,000		
2006 Restricted Stock Grant(4)	3/31/2006	4/1/2006				4,315	$ 300,022
Jay L. Johnson							
2006 Annual Incentive Plan(3)			$ 0	$ 178,092	$ 356,184		
2006 Performance Grant(4)			$ 0	$ 229,500	$ 459,000		
2006 Restricted Stock Grant(4)	3/31/2006	4/1/2006				3,301	$ 229,535
David A. Christian							
2006 Annual Incentive Plan(3)			$ 0	$ 144,239	$ 288,477		
2006 Performance Grant(4)			$ 0	$ 146,250	$ 292,500		
2006 Restricted Stock Grant(4)	3/31/2006	4/1/2006				2,104	$ 146,274
2006 Restricted Stock Grant(5)	12/19/2006	12/20/2006				1,089	$ 90,006

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. The amounts listed in the table reflect only that portion allocated to the Company.

(2) On March 31, 2006, the CGN Committee approved the 2006 long-term compensation awards for our officers which consisted of a restricted stock grant and a performance grant. The 2006 restricted stock award was granted on April 1, 2006. Under Dominion's 2005 Incentive Compensation Plan, fair market value is defined as the average of the high and low prices 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, 2006 restricted stock grant was $69.53 per share and was determined by taking the average of the high and low prices of Dominion stock on March 31, 2006 (grant approval date).

(3) These amounts represent potential payouts under the 2006 Annual Incentive Plan. Actual payouts earned are reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table on page 56. Under the annual incentive program, officers are eligible for an annual performance-based award. The CGN Committee establishes target awards for each executive 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. For the 2006 Annual Incentive Plan, funding is based on the achievement of consolidated operating earnings goals with the maximum funding capped at 200%.

For officers that are among Dominion's top most highly compensated group for 2006, which includes all of our named executive officers except for Mr. Christian, pay-out under the 2006 Annual Incentive Plan is based solely on the achievement of the corporate funding goal, with the CGN Committee having the discretion to lower actual pay-outs to ensure that such awards are consistent with those granted to other plan participants. The 2006 target percentages of base salary for our named executive officers are as follows: Thomas F. Farrell, II – 110%; Thomas N. Chewning – 90%; Mark F. McGettrick and Jay L. Johnson – 80%; and David A. Christian – 70%.

(4) On March 31, 2006, the CGN Committee approved a long-term compensation award for our officers, which consists of two components of equal value: a restricted stock grant and a performance grant. The restricted stock fully vests at the end of three years with dividends paid during the restricted period at the same rate declared by Dominion for all shareholders. The restricted stock award 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 performance grant will be paid in cash in 2008 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 two equally weighted metrics: 1) Dominion's total shareholder return (TSR) for the twenty-one month period ended December 31, 2007 relative to the TSR of a group of industry peers selected by the CGN Committee; and 2) Dominion's return on invested capital (ROIC) for the two-year period ended December 31, 2007. The payout for TSR performance can range from 0% to 200% of the target award and will be interpolated between the following levels:

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

Payout for ROIC performance will range from 0% to 200% of the target award and will be interpolated between the ranges established by the CGN Committee. The performance grant also provides for some form of pro-rata payout in the event an officer retires, dies, becomes disabled, or is terminated without cause. In the event of a Change in Control, payout will accelerate and be equal to the greater of the target amount or the payout amount that would be made for Dominion's goal performance based on Dominion's financial statements as of the day before the Change in Control. See CD&A on page 54 for the definition of a Change in Control.

(5) On December 19, 2006, the CGN Committee approved a restricted stock grant to Mr. Christian in order to secure and retain his services. The restricted stock fully vests at the end of three years with dividends paid during the restricted period at the same rate declared by Dominion for all shareholders. The restricted stock award also provides for pro-rata vesting if an officer dies, becomes disabled, or if there is a Change in Control. The fair market value for the December 20, 2006 restricted stock grant was $82.65 per share and was determined by taking the average of the high and low prices of Dominion stock on December 19, 2006 (grant approval date).

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END (1)

	Option Awards			Stock Awards	
Name	Number of Securities Underlying Unexercised Options Exercisable(2)	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(3)
Thomas F. Farrell, II	70,000	$ 59.96	1/1/2008	14,651(4)	$ 1,228,340
	70,000	$ 59.96	1/1/2009	15,703(5)	$ 1,316,548
	70,000	$ 59.96	1/1/2010	15,101(6)	$ 1,266,106
Thomas N. Chewning	30,000	$ 59.96	1/1/2008	9,070(4)	$ 760,420
	45,000	$ 59.96	1/1/2009	8,153(5)	$ 683,556
	45,000	$ 59.96	1/1/2010	4,315(6)	$ 361,761
Mark F. McGettrick	16,667	$ 59.96	1/1/2009	5,349(4)	$ 448,460
	16,667	$ 59.96	1/1/2010	4,808(5)	$ 403,103
				4,315(6)	$ 361,770
Jay L. Johnson	17,000	$ 59.96	1/1/2008	5,456(4)	$ 457,429
	17,000	$ 59.96	1/1/2009	4,904(5)	$ 411,165
	17,000	$ 59.96	1/1/2010	3,301(6)	$ 276,775
David A. Christian				3,349(4)	$ 280,772
				2,951(7)	$ 247,382
				2,104(6)	$ 176,378
				1,089(8)	$ 91,302

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. The amounts listed in the table reflect only that portion allocated to the Company.

(2) All options presented in this table are fully vested and exercisable. There are no unexercisable options outstanding.

(3) Based on closing stock price of $83.84 on December 29, 2006 which was the last day of the fiscal year on which Dominion stock was traded.

(4) Shares vest on February 24, 2008.

(5) 50% of shares vest on May 11, 2007 based on achievement of certain performance criteria; the remaining shares vest on May 11, 2009.

(6) Shares vest on April 1, 2009.

(7) 50% of shares vested on February 18, 2007 based on achievement of certain performance criteria; the remaining shares vest on February 18, 2009.

(8) Shares vest on December 20, 2009.

OPTION EXERCISES AND STOCK VESTED

	Option Awards	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise
Thomas N. Chewning[1]	15,000	$295,007

(1) Mr. Chewning's options were exercised pursuant to a Rule 10b5-1 trading plan. Mr. Chewning performs services for more than one subsidiary of Dominion and the amounts listed in the table reflect only that portion allocated to the Company.

PENSION BENEFITS[1,2]

No payments were made to any of the Named Executive Officers during Fiscal Year 2006 under any of the plans listed in this table.

Name	Plan Name	Number of Years Credited Service(3)	Present Value of Accumulated Benefit(1)
Thomas F. Farrell, II	Qualified Pension Plan	11.00	$ 71,152
	Benefit Restoration Plan Pre-2005	9.00	140,059
	Supplemental Retirement Plan Pre-2005	9.00	1,415,960
	New Benefit Restoration Plan	19.64	651,509
	New Supplemental Retirement Plan	19.64	1,588,116
Thomas N. Chewning	Qualified Pension Plan	19.00	182,829
	Benefit Restoration Plan Pre-2005	25.00	921,026
	Supplemental Retirement Plan Pre-2005	25.00	1,192,530
	New Benefit Restoration Plan	30.00	189,394
	New Supplemental Retirement Plan	30.00	227,659
Mark F. McGettrick	Qualified Pension Plan	22.50	171,449
	Benefit Restoration Plan Pre-2005	20.50	120,404
	Supplemental Retirement Plan Pre-2005	20.50	173,128
	New Benefit Restoration Plan	27.30	813,948
	New Supplemental Retirement Plan	27.30	696,417
Jay L. Johnson	Qualified Pension Plan	6.33	99,885
	Benefit Restoration Plan Pre-2005	4.33	61,303
	Supplemental Retirement Plan Pre-2005	4.33	568,243
	New Benefit Restoration Plan	12.18	284,286
	New Supplemental Retirement Plan	12.18	630,162
David A. Christian	Qualified Pension Plan	22.50	193,240
	Benefit Restoration Plan Pre-2005	20.50	119,943
	Supplemental Retirement Plan Pre-2005	20.50	224,261
	New Benefit Restoration Plan	22.50	173,003
	New Supplemental Retirement Plan	22.50	543,100

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. The amounts listed in the table reflect only that portion allocated to the Company.

(2) 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.

(3) Years of service for the qualified plan is actual years accrued from date of participation. Pre-2005 service is accrued service up to December 31, 2004. Service for the New Benefit Restoration Plan and New Supplemental Retirement Plan is the pro-rata portion of the contractual service from date of participation.

Dominion Pension Plan

The Dominion Pension Plan (Pension Plan) is a tax-qualified defined benefit pension plan. All executives 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 $220,000 for 2006. 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 before 2001:

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 after 2000:

1.80% times Final Average Earnings times Credited Service after 2000	Minus	1.50% times estimated Social Security benefit times Credited Service after 2000

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.

If a vested participant does not start receiving benefit payments at termination, the participant can start receiving benefit payments at any time after age 55. For terminated vested participants (terminate employment before age 55) the early retirement reduction factors for the portion of the benefits earned after 2000 are as follows: 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%; Age 55 - 55%.

Benefit payment options are a (1) single life annuity, (2) 50% joint and survivor annuity, (3) 100% joint and survivor annuity, and (4) Social Security leveling option with any of the other three benefit forms. The normal form of benefit is the single life annuity. All of the options are actuarial equivalent to the single life annuity. The Social Security leveling option pays a larger benefit equal to the estimated Social Security benefits 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 as well as interest based on the 30-year Treasury bond rate. The SRA can be paid in a lump sum or paid as part of an annuity with the other benefits under the Pension Plan.

Dominion Benefit Restoration Plans

Dominion sponsors the New BRP and the Frozen BRP which are also discussed under *Employee and Executive Benefits* in CD & A. 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.

The restoration benefit offers an additional incentive to attract and retain talented executives for Dominion by compensating them for the reduction in their benefits under Dominion's Pension Plan resulting from the application of limitations on compensation and benefits imposed on tax-qualified pension plans by the Internal Revenue Code.

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 and has had his or her benefit under the Dominion Pension Plan reduced or limited by the Internal Revenue Code. Dominion designates an employee to participate 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 2006, the limit was $220,000. The Internal Revenue Code also limits the total annual benefit that may be provided to a participant under a qualified defined benefit plan. For 2006, this limitation was the lesser of (i) $175,000 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. A participant who terminates employment prior to retirement is generally not entitled to a restoration benefit. However, a participant who becomes totally and permanently disabled prior to retirement or who dies prior to reaching retirement eligibility is entitled to the restoration benefit.

Dominion may grant additional months of service and years of age to participants for purposes of these plans and the supplemental retirement plans described below. Extra age and service credit is granted for mid-career recruiting and retention purposes. Mr. Farrell will be credited with 25 years of service at age 55, and will be credited with 30 years of service at age 60. Mr. Chewning has been credited with 30 years of service. Mr. McGettrick will receive 5 years of additional credited age and service at age 50. Also, if Mr. McGettrick is terminated other than for cause, prior to age 50, he will be credited with the number of years credit needed to give him 55 years of credited age and the number of additional years of service credit needed to give him the same number of years of service that would have been earned had he remained employed by the company until age 55. Mr. Johnson will be credited with 20 years of service once he completes 10 years of actual service. Additional age and years of service may be credited in certain situations pursuant to the terms of individual retirement agreements and arrangements for the named executive officers and is described in *Potential Payments Upon Termination or Change in Control*.

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 generally 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. 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.

For purposes of these plans and the supplemental retirement plans described below, 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, 2006 calculations include: discount rate of 6.20%; Frozen BRP and Frozen ESRP lump sum rate of 4.85%; New BRP and New ESRP lump sum rate of 5.45%; Frozen BRP cost-of-living adjustment of 1.625% and the 1994 Group Annuity Mortality table for post retirement only.

Dominion Executive Supplemental Retirement Plans

Dominion sponsors the New ESRP and the Frozen ESRP which are also discussed under *Employee and Executive Benefits* in CD&A. 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.

The supplemental retirement benefit offers an additional incentive to attract and retain talented executives for Dominion. In light of the competitive industry in which it does business, Dominion feels that the normal pension plan benefit (even as increased by the restoration benefit) is insufficient to fulfill this purpose on its own.

Any elected officer of the company is eligible to participate in the New ESRP. Dominion 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, based on his or her compensation and subject to age and years of service as of retirement, 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, based on his or her compensation and subject to age and years of service as of December 31, 2004. The retirement benefit is only payable for ten years unless Dominion 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 the company'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 reaching 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. Current named executive officers who are entitled to a full ESRP retirement benefit are: Messrs. Chewning and Johnson.

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 retirement benefit, calculated by multiplying the full retirement 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, McGettrick and Christian are the only named executive officers who are not entitled to a full retirement benefit. See discussion above regarding additional months of service and years of age.

A participant who separates from service with Dominion with less than 60 months of service is generally not entitled to a retirement benefit. However, a participant who becomes totally and permanently disabled prior to separation from service is entitled to a full retirement 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 retirement benefit.

A participant's accrued retirement benefit is initially calculated as an annual amount payable in monthly installments for a period of 120 months. However, the New ESRP allows Dominion to designate certain participants as eligible for a retirement benefit for their lifetimes. Messrs. Farrell and Chewning will receive this benefit for their lifetime. Messrs. McGettrick and Christian will receive this benefit for lifetime if employed with Dominion at age 60. Mr. Johnson will receive this benefit for his lifetime after he has completed 10 years of actual service with Dominion.

Under the New ESRP, the retirement benefit is generally paid in the form of a single cash lump sum unless a participant (other than a lifetime participant) elects monthly installment payments guaranteed for 120 months or a lifetime participant elects a single life annuity with 120 guaranteed monthly payments. Under the Frozen ESRP, the retirement 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.

NONQUALIFIED DEFERRED COMPENSATION

Name	Aggregate Earnings in Last FY (Year ended of 12/31/06)(1)	Aggregate Balance at Last FYE (as of 12/31/2006)(1)
Thomas F. Farrell, II	$ 1,938	$ 42,555
Thomas N. Chewning	540	4,824
Mark F. McGettrick	45,235	418,934
Jay L. Johnson	30,956	286,887
David A. Christian	430	10,365

Footnote:

(1)The executive officers included in this table may perform services for more than one subsidiary of Dominion. The amounts listed in the table reflect only that portion allocated to the Company. Dominion does not currently offer any nonqualified deferred compensation plans to its officers or other employees. The Aggregate Balance at Last FYE column includes salary and bonus deferrals, lost company savings plan match and vested restricted stock which would have been reported in prior years' Summary Compensation Tables.

The 2006 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 amended and restated as of December 31, 2004 to "freeze" the plan as of that date (the Frozen Deferred Compensation Plan); and The Dominion Resources, Inc. Security Option Plan, which was amended and restated effective December 31, 2004 to "freeze" the plan as of that date (the 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 under the plan 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 lost company savings 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 vesting 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 on page 56.

The named executive officers invested in the following funds which had rates of returns for 2006 as noted below. Except for the Fixed Income Fund, all of the funds have the same rate of returns as corresponding publicly available mutual funds.

Vanguard 500 Index Fund	18.6%
Dominion Resources Stock Fund	12.0%
Dominion Fixed Income Fund	5%

The Fixed Income Fund is an option that provides a fixed return rate set prior to the beginning of the year. The investment management department of Dominion 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 have the ability to change their distribution schedule for benefits under the plan with six months notice to the plan administrator. 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.
- In February of a specific calendar year.

The default Benefit Commencement Date is February 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, ten calendar years after a participant retires or becomes disabled. If a participant retires, 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 1 to 10 years. 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 the company 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 savings 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 26 mutual funds, and there is not a Dominion stock alternative nor 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.
- Options expire on the last day of the 120th month after severance following a Change in Control.

The executives in the Nonqualified Deferred Compensation Table held options on the following publicly available mutual funds which had the rates of returns for 2006 as noted below.

Vanguard Balanced Index Fund	11.0%
Vanguard Short-Term bond Index	4.1%
Vanguard Small Cap Growth Index	12.0%
Vanguard Small Cap Index	15.7%
Vanguard Extended Market Index	14.3%
Vanguard U.S. Value	14.1%
Artisan International Investor	25.6%
Harbor International Instl Fund	32.7%
Janus Growth & Income Fund	7.8%
Janus Mid Cap Value Investor	15.3%

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

Termination Without Cause, Voluntary Termination, Retirement or Termination upon Death or Disability as of 12/31/2006 (Messrs. Chewning and Johnson)(1)

Under terms of Dominion's qualified plan, Messrs. Chewning and Johnson are eligible for retirement as of December 31, 2006. In addition to the benefits outlined below, they would receive the benefits provided above in the Pension Benefits table, with the following reduction in benefit for early retirement versus the assumed retirement ages used in the Pension Benefit table for Mr. Johnson ($515,521). Also, Mr. Chewning would be eligible for retiree medical benefits under the company's plan for all employees, whereas Mr. Johnson would not be eligible as he does not have ten years of service with the company. The following table assumes they retire in connection with any termination without cause, voluntary termination or termination upon death or disability.

Name	Restricted Stock Awards (2)	Performance Grant Awards	Executive Life Insurance	Unused Vacation Benefit	Special Payments (Non-compete)(3)	Total
Thomas N. Chewning	$ 1,534,417	$ 128,639	$ 83,582	$ 22,370	$ 180,000	$ 1,949,008
Jay L. Johnson	937,788	98,409	0	27,399	0	1,063,596

Footnotes:

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. The amounts listed in the table reflect only that portion allocated to the Company.

(2) Grants made prior to 2006 are fully vested upon retirement. Grants made in 2006 and after vest pro-rata upon retirement.

(3) 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 requirement.

Termination Without Cause as of 12/31/2006 (Messrs. Farrell, McGettrick and Christian)(1)

Mr. McGettrick will be credited with the number of years needed to give him 55 years of credited age, and the number of additional years needed to give him the same number of years of service that he would have earned had he remained employed until age 55, if he is terminated other than for cause prior to age 50. At age 50 and above, if he is terminated without cause, he will receive 5 years of additional credited age and service. Mr. McGettrick is currently age 49. Therefore, the table below assumes Mr. McGettrick is credited with 55 years of age, and 28 years of service. This would entitle him to participate in retiree medical coverage and life insurance under the same terms and conditions as retired employees of Dominion, and will entitle him to be treated as a retired executive for purposes of Dominion's Executive Life Insurance Program, stock and incentive grants. Mr. Farrell is not retirement eligible, but under the terms of his letter agreement with Dominion in connection with his election as CEO, his 2003 and 2004 restricted stock grants will vest in their entirety upon termination without cause, and he will be entitled to participate in retiree medical coverage without regard to his age or service to the same extent as retired employees of Dominion.

Name	Nonqualified Retirement Plans(2)	Restricted Stock Awards(3)	Performance Grant Awards	Executive Life Insurance(4)	Retiree Medical(5)	Unused Vacation Benefit	Total
Thomas F. Farrell, II	$ 3,111,462	$2,861,414	$ 450,235	$ 0	$28,840	$ 35,674	$6,487,625
Mark F. McGettrick	2,256,564	942,006	128,639	12,043	47,565	32,435	3,419,252
David A. Christian	619,806	44,095	62,711	0	0	25,312	751,924

Footnotes:

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. The amounts listed in the table reflect on that portion allocated to the Company.

(2) Messrs. Farrell, McGettrick and Christian are also entitled to a qualified pension plan benefit beginning at age 55. The estimated monthly life annuity benefit for Messrs. Farrell, McGettrick and Christian would be $571, $1,835 and $1,635, respectively.

(3) Under Messrs. Farrell and McGettrick's individual agreements, grants made prior to 2006 are fully vested upon termination without cause. Mr. Christian will forfeit any grants prior to 2006 upon termination without cause. Messrs. Farrell, McGettrick and Christian will receive pro-rata vesting on any grants awarded in 2006 and after upon termination without cause.

(4) Amounts reflect annual premiums payable for the later of ten years or age 64.

(5) This represents the present value of the retiree medical benefit that Messrs. Farrell and McGettrick would receive due to their letter agreements.

Voluntary Termination (Messrs. Farrell, McGettrick and Christian)

Mr. Farrell would receive a nonqualified retirement plan benefit of $3,111,462 with all restricted stock and performance grants forfeited. Messrs. McGettrick and Christian would receive a nonqualified retirement plan benefit of $678,922 and $619,806, respectively with all restricted stock and performance grants forfeited. Messrs. Farrell, McGettrick and Christian would be entitled to qualified pension plan benefits at age 55. The estimated monthly life annuity benefit for Messrs. Farrell, McGettrick and Christian would be $571, $1,835 and $1,635, respectively. Messrs. Farrell, McGetrrick and Christian would also be entitled to unused vacation benefits of $35,674, $32,435 and $25,312, respectively.

Termination Due to Death/Disability (Messrs. Farrell, McGettrick and Christian)

Messrs. Farrell, McGettrick and Christian would be treated as if they retired on date of death under the Benefit Restoration Plan. For the Executive Supplemental Retirement Plan, they would receive the benefit they would be entitled to as of the date of death or disability as though they were 55. They would be fully vested in restricted stock grants made prior to 2006 and would be pro-rata vested in grants made in 2006 and forward. Messrs. Farrell, McGettrick and Christian would receive benefits indicated in the Termination without Cause table shown above except that (i) Messrs. Farrell and Christian would receive $3,867,572 and $801,092, respectively under Nonqualified Retirement Plans. Instead of the amounts shown under Nonqualified Retirement Plan column in that table; and (ii) in the event of death, the Executive Life Insurance and Retiree Medical benefits would not be paid.

Termination with Cause

Messrs. Chewning and Johnson are eligible for retirement as of December 31, 2006; therefore, if allowed to retire under all of Dominion's benefit plans in connection with a termination with cause, they would receive the benefits described above under Termination without Cause, Voluntary Termination, Retirement or Termination upon Death or Disability. However, the Board may lower this amount depending on the circumstances: (i) the claw-back policy allows for recovery of any performance-based compensation if it was based on financial results that were subject to any restatement due to the officer's fraud or negligence; and (ii) the CGN Committee can remove the officer as a participant in the nonqualified retirement plans, reducing the final compensation due by the amounts reflected in Pension Benefits table.

For Messrs. Farrell, McGettrick and Christian upon termination with cause, they would receive payments of $3,111,462, $678,922 and $619,806, respectively under the terms of the nonqualified retirement plans, subject to the claw-back and removal from plan remedies discussed above. All shares of restricted stock and performance grants are forfeited upon a termination for cause. Messrs. Farrell, McGettrick and Christian would be entitled to qualified pension plan benefits at age 55. The estimated monthly life annuity benefit for Messrs. Farrell, McGettrick and Christian would be $571, $1,835 and $1,635, respectively. Messrs. Farrell, McGetrrick and Christian would also be entitled to unused vacation benefits of $35,674, $32,435 and $25,312, respectively.

Change in Control

Dominion has entered into an Employment Continuity Agreement with each of its officers, including the named executive officers. 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 the Company in the event of an anticipated or actual Change in Control at Dominion. In a time of transition, it is critical to company performance to retain and continue to motivate the company's core management team. In a change of control situation, workloads typically increase dramatically, outside competitors are more likely to attempt to recruit top performers away from the company, 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.

The Employment Continuity Agreements provide benefits in the event of a Change in Control. Each agreement has a three-year term and is automatically extended annually for an additional year, unless cancelled by Dominion.

The agreements indemnify the executive for excise taxes and fees associated with the enforcement of the agreements. If an executive is terminated for cause, the agreements are not effective.

Dominion's Continuity Agreements require two triggers for the payments of the benefits disclosed in the tables below:

- There must be a Change in Control which is defined in CD&A on page 54 ; 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 (Constructive Termination).

The table below provides the payments that would be earned by each named executive officer if they were terminated, or constructively terminated, as of December 31, 2006 as a result of a Change in Control. For officers that are retirement eligible (Messrs. Chewning and Johnson), these benefits would be in addition to the retirement benefits discussed above. For executives that are not retirement eligible (Messrs. Farrell, McGettrick and Christian), these benefits are in addition to the benefits they would receive for a termination without cause disclosed above. All stock options held by our named executive officers are vested. In 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.

All cash payments disclosed in the table below are payable as a lump sum, unless noted otherwise. Certain lump-sum amounts will be paid six months after termination in order to be in compliance with the Internal Revenue Code.

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Termination, including Constructive Termination, Due to Change in Control as of 12/31/2006 (1)

	3 Times Salary & Bonus	5 Years Extra Age & Service	Vesting of Restricted Stock Awards	Payout of Performance Grant Awards	Outplace-ment Services	Executive Life Insurance (2)	Misc. Benefits (3)	Excise Tax & Tax Gross-Ups	Totals
Thomas F. Farrell, II	$ 2,205,000	$ 1,959,819	$ 949,579	$ 599,765	$ 8,750	$ 19,388	$ 32,501	$ 2,557,657	$ 8,332,459
Thomas N. Chewning	1,026,000	0	271,321	171,362	7,500	0	7,564	0	1,483,747
Mark F. McGettrick	1,417,500	855,609	271,327	171,362	12,500	12,043	21,320	1,289,089	4,050,750
Jay L. Johnson	1,202,121	237,458	207,581	131,091	12,750	25,699	52,808	910,814	2,780,322
David A. Christian	1,050,881	1,526,423	751,740	83,539	11,250	8,976	65,951	1,576,917	5,075,677

Footnotes:

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. The amounts listed in the table reflect only that portion allocated to the Company.

(2) Amounts reflect annual premiums paid under the terms of the Employment Continuity Agreements. For Mr. Chewning, this benefit is disclosed as a retirement benefit in the table on page 63. For Messrs. Farrell, McGettrick, Johnson and Christian, life insurance premium payments would be made for five years if terminated as of December 31, 2006 in connection with a Change in Control.

(3) Miscellaneous benefits include:

- COBRA premiums for dental and vision coverage for 36 months.
- The value of retiree medical coverage for which they are not eligible without a Change in Control.
- Employee Term Life Insurance and Disability Insurance premium payments for 36 months from the date of the Change in Control.
- Unused vacation that is not allowed to be sold under the vacation policy (up to one week), but could be sold under a Change in Control event.

COMPENSATION COMMITTEE REPORT

The Company is a wholly-owned subsidiary of Dominion. Our Board is comprised of Messrs. Farrell and Chewning, who are executive officers of the Company. 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 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 the Dominion CGN Committee's 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
February 28, 2007

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The table below sets forth as of February 9, 2007, the number of shares of Dominion common stock owned by directors and the executive officers named on the Summary Compensation Table.

Name of Beneficial Owner	Shares	Restricted Shares	Exercisable Stock Options	Total	Deferred Compensation(1)
Thomas F. Farrell, II(2)	132,670	129,873	500,000	762,543	—
Thomas N. Chewning(4)	114,352	71,793	400,000	586,145	192
Jay L. Johnson	23,561	26,787	33,334	83,682	4,813
Mark F. McGettrick	25,692	28,944	66,667	121,303	5,799
David A. Christian	20,652	21,094	—	41,746	—
All directors and executive officers as a group (7 persons)(3)	345,211	313,095	1,140,001	1,798,307	20,293

(1)Amounts in this column represent share equivalents under a deferred compensation plan and do not have voting rights.

(2)Mr. Farrell disclaims ownership for 399 shares.

(3)All directors and executive officers as a group own less than one percent of the number of Dominion common shares outstanding as of February 9, 2007. No individual executive officer or director owns more than one percent of the shares outstanding.

(4)Mr. Chewning pledged 96,960 shares as collateral for a Wachovia Bank loan to a nonprofit organization. Based on the February 9, 2007 closing price of $87.46, if the loan for which these shares are pledged defaults, Wachovia Bank has the right to approximately 36,800 shares.

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 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. The term related person includes not only our directors and executive officers, but others related to them by certain family or business ties. The guidelines spell out in greater detail the practices outlined in our Code of Ethics and procedures already being followed.

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. Potential related party transactions are first reviewed by the Corporate Secretary and the General Counsel to consider the materiality of the transaction and then reported to Dominion's CGN Committee. Dominion's CGN Committee reviews and considers relevant facts and circumstances and determines whether to ratify, approve or deny the related party transactions identified. Since January 1, 2006 there have been no related party transactions 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. Our Board of Directors is comprised entirely of executive officers of the Company. The Board has determined that Thomas F. Farrell, II and Thomas N. Chewing, as executive officers of the Company, are not independent.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table presents fees paid to Deloitte & Touche LLP for the fiscal years ended December 31, 2006 and 2005.

Type of Fees	**2006**	2005
(millions)		
Audit fees	**$0.77**	$1.04
Audit-related	**0.04**	0.27
Tax fees	—	0.61
All other fees	—	—
	$0.81	$1.92

Audit Fees are for the audit and review of our financial statements in accordance with generally accepted auditing standards, including comfort letters, statutory and regulatory audits, consents and services related to SEC matters.

Audit-Related Fees are for assurance and related services that are related to the audit or review of our financial statements, including employee benefit plan audits, due diligence services and financial accounting and reporting consultation.

Tax Fees reflect the settlement of outstanding arrangements related to tax planning assistance.

Our Board has adopted a pre-approval policy for Deloitte & Touche LLP services and fees. Attached to the policy is a schedule that details the services to be provided and an estimated range of fees to be charged for such services. In December 2006, Dominion's Audit Committee approved the services and fees for 2007.

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 24.

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); 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); and Eighty-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 20, 1997, 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, dated June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 3, 1999, File No.1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K, dated October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); and Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated January 24, 2002, incorporated by reference); Seventh Supplemental Indenture dated September 1, 2002 (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, 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 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).
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	Amended and Restated Interconnection and Operating Agreement, dated as of July 29, 1997 between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(v), Form 10-K for the fiscal year ended December 31, 1997, File No. 1-8489, incorporated by reference).
10.2	Services Agreement between Dominion Resources Services, Inc. and Virginia Electric and Power Company dated January 1, 2000 (Exhibit 10.19, Form 10-K for the fiscal year ended December 31, 1999, File No. 1-2255, incorporated by reference).
10.3	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).

10.4	$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).
10.5*	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).
10.6*	Dominion Resources, Inc. Incentive Compensation Plan, effective April 22, 1997, as amended and restated effective July 20, 2001 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2001, File No. 1-2255, incorporated by reference).
10.7*	Dominion Resources, Inc. 2005 Incentive Compensation Plan (Exhibit 10, Form 8-K filed March 3, 2004, File No. 1-8489, incorporated by reference).
10.8*	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).
10.9*	Form of Performance Grant under 2006 Long-Term Compensation Program approved March 31, 2006 (Exhibit 10.2, Form 8-K filed April 4, 2006, File No. 1-8489, incorporated by reference).
10.10*	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).
10.11*	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).
10.12*	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).
10.13*	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).
10.14*	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 (filed herewith), and further amended January 1, 2007 (filed herewith).
10.15*	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 (filed herewith).
10.16*	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).
10.17*	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).
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).
23.1	Consent of Deloitte & Touche LLP (filed herewith).
23.2	Consent of Jackson & Kelly PLLC (filed herewith).
23.3	Consent of McGuire Woods 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).

* Indicates management contract or compensatory plan or arrangement.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VIRGINIA ELECTRIC AND POWER COMPANY

By: /S/ THOMAS F. FARRELL, II

(Thomas F. Farrell, II,
Chairman of the Board of Directors
and Chief Executive Officer)

Date: February 28, 2007

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 28th day of February, 2007.

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/ STEVEN A. ROGERS **Steven A. Rogers**	Senior Vice President and Chief Accounting Officer

Exhibit 10.14

**AMENDMENT
TO THE DOMINION RESOURCES, INC.
NEW EXECUTIVE SUPPLEMENTAL RETIREMENT PLAN**

AMENDMENT, effective January 1, 2007, to the Dominion Resources, Inc. New Executive Supplemental Retirement Plan (the "Plan").

Dominion Resources, Inc. (the "Company") maintains the Plan, as originally effective as of January 1, 2005. The Board of Directors of the Company or its delegate has the power (pursuant to Section 8.1 of the Plan) to amend the Plan and has delegated certain authority to amend such plan to the Dominion Resources Services, Inc. CEO (the "Services CEO"). Pursuant to such delegation, the Services CEO can authorize amendments that do not materially increase or enhance benefits to be provided under the Plan.

The Administrative Benefit Committee of the Company's Board of Directors (the "Committee") has the authority under the Plan to determine the actuarial and other factors to be used in calculating the lump-sum equivalent value of accrued Plan benefits. In its December 12, 2006 meeting, the Committee recommended that a set rate of 4% be established for the actuarial discount rate for lump-sum distributions under the Plan during calendar years 2007 through 2009.

NOW, THEREFORE, effective January 1, 2007, Section 1.15 of the Plan is hereby amended in its entirety as follows:

1.15 "Lump Sum Equivalent" means a single lump sum payment that is actuarially determined as the amount required to provide an after-tax monthly payment equal to one-twelfth of the after-tax amount of the Annual Benefit. Effective for distributions occurring on or after January 1, 2007 and on or before December 31, 2009, unless otherwise determined by the Administrative Benefit Committee, the actuarial discount rate for determinations of the Lump Sum Equivalent shall be 4 percent (4%). Beginning January 1, 2010, the actuarial discount rate shall be determined by the Administrative Benefit Committee. The actuarial determination shall be computed using any other actuarial or other factors as determined by the Administrative Benefit Committee. The after-tax amounts shall be based on Federal income and FICA tax rates and the state income tax rate for the residence of the Participant at the date of the payment, as determined by the Administrative Benefit Committee.

FIRST AMENDMENT TO
DOMINION RESOURCES, INC.
NEW EXECUTIVE SUPPLEMENTAL RETIREMENT PLAN

FIRST AMENDMENT, effective December 1, 2006, to the Dominion Resources, Inc. New Executive Supplemental Retirement Plan (the "Plan").

Dominion Resources, Inc. (the "Company") maintains the Plan, as originally effective as of January 1, 2005. The Board of Directors of the Company or its delegate has the power (pursuant to Section 8.1 of the Plan) to amend the Plan and has delegated certain authority to amend such plan to the Dominion Resources Services, Inc. CEO (the "Services CEO"). Pursuant to such delegation, the Services CEO has authorized amendments that do not materially increase or enhance benefits to be provided under the Plan.

NOW, THEREFORE, effective December 1, 2006, the Plan is hereby amended as follows:

1. Section 1.10 of the Plan is hereby amended in its entirety as follows:

1.10 "Eligibility Conditions":

(a) For any Participant who becomes a Participant on or after December 1, 2006, "Eligibility Conditions" means either reaching age fifty-five (55) and completing sixty (60) months of Participant Service, or being deemed to have reached age fifty-five (55) and have completed sixty (60) months of Participant Service due to a Benefit Agreement.

(b) For any Participant who became a Participant on or before November 30, 2006, "Eligibility Conditions" means either reaching age fifty-five (55) and completing sixty (60) months of service, or being deemed to have reached age fifty-five (55) and have completed sixty (60) months of service due to a Benefit Agreement.

2. A new Section 1.17A is hereby added to the Plan immediately following current Section 1.17 of the Plan as follows:

1.17A "Participant Service" means service with the Company while a Participant in the Plan. Service with the Company while an individual is not a Participant in the Plan is disregarded for purposes of calculating Participant Service.

3. Section 1.21 of the Plan is hereby amended in its entirety as follows:

1.21 "Retirement" and "Retire" mean severance from employment with the Company on or after meeting the Eligibility Conditions and which also constitutes a separation from service for purposes of Code Section 409A.

4. Section 3.1(c) is hereby amended in its entirety as follows:

(c) If a Regular Participant or Life Participant subject to the Eligibility Conditions in Section 1.10(a) has completed sixty (60) months of Participant Service (actually or deemed under a Benefits Agreement), or if a Regular Participant or Life Participant subject to the Eligibility Conditions in Section 1.10(b) has completed sixty (60) months of service with the Company (actually or deemed under a Benefits Agreement), then, in either case, upon his severance from employment with the Company before the attainment of fifty-five (55) years of age (actually or deemed under a Benefits Agreement), the Participant shall be entitled to an Annual Benefit equal to the benefit computed under Section 3.1(a) or Section 3.1(b), as applicable, multiplied by the following fraction (not greater than one):

$$\frac{\text{Participant's completed months of Participant Service (if subject to Section 1.10(a)) or service with the Company (if subject to Section 1.10(b))}}{\text{Total months from the date on which the individual became a Participant to the Participant's attainment of fifty-five (55) years of age (actually or deemed under a Benefits Agreement).}}$$

For purposes of the above calculation, partial months shall be disregarded. The actuarial equivalent of the benefit under this Section 3.2(c) shall be paid in the form of the Lump Sum Equivalent.

5. The first sentence of Section 7.2 of the Plan is hereby amended in its entirety as follows:

Except as otherwise provided in Section 7.3, a Participant (a) who is removed or not reelected as an officer or (b) whose employment with the Company terminates for any reason other than death or Total and Permanent Disability before the Participant has completed sixty (60) months of either (i) Participant Service (actually or deemed under a Benefits Agreement) if the Participant is subject to the Eligibility Conditions in Section 1.10(a), or (ii) service with the Company (actually or deemed under a Benefits Agreement) if the Participant is subject to the Eligibility Conditions in Section 1.10(b), shall in either case immediately cease to be a Participant under this Plan and shall forfeit all rights under this Plan.

6. In all respects not amended, the Plan is hereby ratified and confirmed.

Exhibit 10.15

AMENDMENT
TO THE DOMINION RESOURCES, INC.
NEW BENEFIT RESTORATION PLAN

AMENDMENT, effective January 1, 2007, to the Dominion Resources, Inc. New Benefit Restoration Plan (the "Plan").

Dominion Resources, Inc. (the "Company") maintains the Plan, as originally effective as of January 1, 2005. The Board of Directors of the Company or its delegate has the power (pursuant to Section 8.1 of the Plan) to amend the Plan and has delegated certain authority to amend such plan to the Dominion Resources Services, Inc. CEO (the "Services CEO"). Pursuant to such delegation, the Services CEO can authorize amendments that do not materially increase or enhance benefits to be provided under the Plan.

The Administrative Benefit Committee of the Company's Board of Directors (the "Committee") has the authority under the Plan to determine the actuarial and other factors to be used in calculating the lump-sum equivalent value of accrued Plan benefits. In its December 12, 2006 meeting, the Committee recommended that a set rate of 4% be established for the actuarial discount rate for lump-sum distributions under the Plan during calendar years 2007 through 2009.

NOW, THEREFORE, effective January 1, 2007, Section 1.12 of the Plan is hereby amended in its entirety as follows:

1.12 "Lump Sum Equivalent" means a single lump sum payment that is actuarially determined as the amount required to provide an after-tax monthly payment equal to the after-tax amount of the Monthly Benefit payable for the period determined under Section 3.1(b). Effective for distributions occurring on or after January 1, 2007 and on or before December 31, 2009, unless otherwise determined by the Administrative Benefit Committee, the actuarial discount rate for determinations of the Lump Sum Equivalent shall be 4 percent (4%). Beginning January 1, 2010, the actuarial discount rate shall be determined by the Administrative Benefit Committee. The actuarial determination shall be computed using any other actuarial or other factors as determined by the Administrative Benefit Committee. The after-tax amounts shall be based on Federal income and FICA tax rates and the state income tax rate for the residence of the Participant at the date of the payment, as determined by the Administrative Benefit Committee.

Exhibit 12.1

Virginia Electric and Power Company
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

	Years Ended				
	2006	2005	2004	2003	2002
Earnings, as defined:					
Earnings from continuing operations before income taxes and minority interests in consolidated subsidiaries	$ 762	$ 754	$ 929	$ 875	$1,248
Fixed charges included in the determination of net income	313	333	258	309	301
Total earnings, as defined	$1,075	$1,087	$1,187	$1,184	$1,549
Fixed charges, as defined:					
Interest charges	$ 311	$ 329	$ 256	$ 318	$ 308
Rental interest factor	11	10	9	10	10
Total fixed charges, as defined	$ 322	$ 339	$ 265	$ 328	$ 318
Ratio of Earnings to Fixed Charges	3.34	3.21	4.48	3.61	4.87

Exhibit 12.2

Virginia Electric and Power Company
Computation of Ratio of Earnings to Fixed Charges and Preferred Dividends
(millions of dollars)

	Years Ended				
	2006	**2005**	**2004**	**2003**	**2002**
Earnings, as defined:					
Earnings from continuing operations before income taxes and minority interests in consolidated subsidiaries	$ 762	$ 754	$ 929	$ 875	$1,248
Fixed charges included in the determination of net income	313	333	258	309	301
Total earnings, as defined	$1,075	$1,087	$1,187	$1,184	$1,549
Fixed charges, as defined:					
Interest charges	$ 311	$ 329	$ 256	$ 318	$ 308
Preference security dividend requirements of consolidated subsidiaries	25	25	25	25	25
Rental interest factor	11	10	9	10	10
Total fixed charges, as defined	$ 347	$ 364	$ 290	$ 353	$ 343
Ratio of Earnings to Fixed Charges and Preferred Dividends	**3.10**	**2.99**	**4.09**	**3.35**	**4.52**

Virginia Electric and Power Company
Subsidiaries of the Registrant
As of December 31, 2006

Name	Jurisdiction of Incorporation	Name Under Which Business is Conducted
Virginia Electric and Power Company	Virginia	Dominion Virginia Power (in Virginia) Dominion North Carolina Power (in North Carolina)
Virginia Power Capital Trust II	Delaware	Virginia Power Capital Trust II
Virginia Power Fuel Corporation	Virginia	Virginia Power Fuel Corporation
Virginia Power Services, LLC	Virginia	Virginia Power Services, LLC
Dominion Generation Corporation	Virginia	Dominion Generation Corporation
Virginia Power Services Energy Corp., Inc.	Virginia	Virginia Power Services Energy Corp., Inc.
Virginia Power Nuclear Services Company	Virginia	Virginia Power Nuclear Services Company
VP Property, Inc.	Virginia	VP Property, Inc.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-96973 and 333-130932 on Forms S-3 of our report dated February 28, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph as to a change in accounting principle for conditional asset retirement obligations in 2005), relating to the consolidated financial statements of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Resources, Inc.), appearing in this Annual Report on Form 10-K of Virginia Electric and Power Company for the year ended December 31, 2006.

/s/ Deloitte & Touche LLP
Richmond, Virginia
February 28, 2007

February 26, 2007

Virginia Electric and Power Company
One James River Plaza
701 East Cary Street
Richmond, Virginia 23219

Re: Form 10-K for the Fiscal Year Ended December 31, 2006

Ladies and Gentlemen:

We consent to the incorporation by reference into the Registration Statements of Virginia Electric and Power Company on Form S-3 File Nos. 333-38510 and 333-96973 of the statements included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2006, made in regard to our Firm that are governed by the laws of West Virginia which relate solely to legal conclusions regarding title to properties.

Very truly yours,

/s/ Jackson Kelly PLLC

JACKSON KELLY PLLC

McGuireWoods LLP
One James Center
901 East Cary Street
Richmond, Virginia 23219

February 28, 2007

Virginia Electric and Power Company
120 Tredegar Street
Richmond, Virginia 23219

Annual Report on Form 10-K

Ladies and Gentlemen:

We consent to the incorporation by reference into the statements made in regard to our firm in the Registration Statement of Virginia Electric and Power Company on Form S-3 (File No. 333-96973) and related prospectuses of the legal conclusions that relate to the Company's franchises and title to properties included in this Annual Report on Form 10-K.

Sincerely,

/s/ McGuireWoods LLP

Exhibit 31.1

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

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

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

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

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

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

   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2007

/s/ Thomas F. Farrell, II

Thomas F. Farrell, II
Chairman and Chief Executive Officer

I, Thomas N. Chewning, certify that:

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

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

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

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

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

   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2007

/s/ Thomas N. Chewning
Thomas N. Chewning
Executive Vice President and Chief Financial Officer

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of Virginia Electric and Power Company (the Company), certify that:

1. the Annual Report on Form 10-K for the year ended December 31, 2006 (the "Report") of the Company to which this certification is an exhibit fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)).

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of December 31, 2006 and for the period then ended.

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
Chief Executive Officer
February 28, 2007

/s/ Thomas N. Chewning
Thomas N. Chewning
Executive Vice President and
Chief Financial Officer
February 28, 2007

FORM 10-Q

DOMINION RESOURCES INC /VA/ - D

Filed: November 01, 2007 (period: September 30, 2007)

Quarterly report which provides a continuing view of a company's financial position

PART I

PART I.

PART II.

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

FORM 10-Q

(Mark one)

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

For the quarterly period ended September 30, 2007

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 001-08489

Dominion®

DOMINION RESOURCES, INC.
(Exact name of registrant as specified in its charter)

VIRGINIA *(State or other jurisdiction of incorporation or organization)*	**54-1229715** *(I.R.S. Employer Identification No.)*
120 TREDEGAR STREET RICHMOND, VIRGINIA *(Address of principal executive offices)*	**23219** *(Zip Code)*

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

At September 30, 2007, the latest practicable date for determination, 287,724,069 shares of common stock, without par value, of the registrant were outstanding.

DOMINION RESOURCES, INC.

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DOMINION RESOURCES, INC.
PART I. FINANCIAL INFORMATION
ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(millions, except per share amounts)				
Operating Revenue	$ 3,589	$3,973	$11,980	$12,375
Operating Expenses				
Electric fuel and energy purchases	914	1,057	2,742	2,580
Purchased electric capacity	111	122	339	361
Purchased gas	346	343	2,024	2,153
Other energy-related commodity purchases	64	144	184	862
Other operations and maintenance	1,159	502	3,906	2,123
Gain on sale of U.S. non-Appalachian E&P business	(3,617)	—	(3,602)	—
Depreciation, depletion and amortization	284	389	1,116	1,146
Other taxes	113	122	436	430
Total operating expenses	(626)	2,679	7,145	9,655
Income from operations	4,215	1,294	4,835	2,720
Other income	33	43	125	134
Interest and related charges:				
Interest expense	403	218	862	658
Interest expense – junior subordinated notes payable[(1)]	30	34	100	94
Subsidiary preferred dividends	4	4	12	12
Total interest and related charges	437	256	974	764
Income from continuing operations before income taxes, minority interest and extraordinary item	3,811	1,081	3,986	2,090
Income tax expense	1,498	421	1,576	750
Minority interest expense (income)	(7)	5	7	5
Income from continuing operations before extraordinary item	2,320	655	2,403	1,335
Extraordinary item[(2)]	—	—	(158)	—
Income (loss) from discontinued operations[(3)]	(3)	(1)	(5)	14
Net Income	$ 2,317	$ 654	$ 2,240	$ 1,349
Earnings Per Common Share – Basic[(4)]				
Income from continuing operations before extraordinary item	$ 7.30	$ 1.86	$ 7.10	$ 3.82
Extraordinary item	—	—	(0.47)	—
Income (loss) from discontinued operations	(0.01)	—	(0.01)	0.04
Net income	$ 7.29	$ 1.86	$ 6.62	$ 3.86
Earnings Per Common Share – Diluted[(4)]				
Income from continuing operations before extraordinary item	$ 7.25	$ 1.85	$ 7.05	$ 3.80
Extraordinary item	—	—	(0.46)	—
Income (loss) from discontinued operations	(0.01)	—	(0.01)	0.04
Net income	$ 7.24	$ 1.85	$ 6.58	$ 3.84
Dividends paid per common share[(4)]	$ 0.71	$ 0.69	$ 2.13	$ 2.07

(1) Includes affiliated interest expense of $17 million and $29 million for the three months ended September 30, 2007 and 2006, respectively, and $61 million and $86 million for the nine months ended September 30, 2007 and 2006, respectively.

(2) Net of income tax benefit of $101 million.

(3) Includes income tax expense of $3 million and $116 million for the three and nine months ended September 30, 2007, respectively. Net of income tax benefit of $1 million for the three months ended September 30, 2006. Includes income tax benefit of $17 million for the nine months ended September 30, 2006.

(4) Per share figures do not reflect the effects of a two-for-one stock split approved by our board of directors on October 26, 2007. Dominion shareholders of record on November 9, 2007 will receive one additional share of common stock for each share held at the close of business on that date. See Note 10 for further details.

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

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DOMINION RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(millions)	September 30, 2007	December 31, 2006(1)
ASSETS		
Current Assets		
Cash and cash equivalents	$ 469	$ 138
Customer receivables (less allowance for doubtful accounts of $29 and $26)	1,687	2,395
Other receivables (less allowance for doubtful accounts of $13 and $13)	256	358
Inventories	1,072	1,101
Derivative assets	1,244	1,593
Assets held for sale	1,096	1,391
Prepayments	115	254
Other	864	868
Total current assets	6,803	8,098
Investments		
Nuclear decommissioning trust funds	2,942	2,791
Other	1,051	1,034
Total investments	3,993	3,825
Property, Plant and Equipment		
Property, plant and equipment	32,915	43,575
Accumulated depreciation, depletion and amortization	(12,054)	(14,193)
Total property, plant and equipment, net	20,861	29,382
Deferred Charges and Other Assets		
Goodwill	3,496	4,298
Pension and other postretirement benefit assets	1,312	1,246
Other	2,061	2,420
Total deferred charges and other assets	6,869	7,964
Total assets	$ 38,526	$ 49,269

(1) Our Consolidated Balance Sheet at December 31, 2006 has been derived from the audited Consolidated Financial Statements at that date.

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

DOMINION RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(millions)	September 30, 2007	December 31, 2006(1)
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Securities due within one year	$ 799	$ 2,478
Short-term debt	—	2,332
Accounts payable	1,330	2,142
Derivative liabilities	1,787	2,276
Liabilities held for sale	414	497
Accrued taxes	3,075	185
Other	955	1,319
Total current liabilities	8,360	11,229
Long-Term Debt		
Long-term debt	11,002	12,842
Junior subordinated notes payable:		
Affiliates	678	1,151
Other	798	798
Total long-term debt	12,478	14,791
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	4,097	5,858
Asset retirement obligations	1,715	1,930
Regulatory liabilities	1,190	614
Other	1,152	1,654
Total deferred credits and other liabilities	8,154	10,056
Total liabilities	28,992	36,076
Commitments and Contingencies (see Note 19)		
Minority Interest	29	23
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	257	257
Common Shareholders' Equity		
Common stock – no par(2)	5,694	11,250
Other paid-in capital	165	128
Retained earnings	3,438	1,960
Accumulated other comprehensive loss	(49)	(425)
Total common shareholders' equity	9,248	12,913
Total liabilities and shareholders' equity	$38,526	$ 49,269

(1) Our Consolidated Balance Sheet at December 31, 2006 has been derived from the audited Consolidated Financial Statements at that date.
(2) 500 million shares authorized; 288 million shares outstanding at September 30, 2007 and 349 million shares outstanding at December 31, 2006.

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

DOMINION RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

Nine Months Ended September 30,	2007	2006
(millions)		
Operating Activities		
Net income	$ 2,240	$ 1,349
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale of non-Appalachian E&P business	(3,796)	—
Impairment of merchant generation assets	387	—
Costs associated with early retirement of debt	242	—
Extraordinary item, net of income taxes	158	—
Charges related to termination of volumetric production payment agreements	139	—
Dominion Capital, Inc. impairment losses	86	89
Charges related to pending sale of gas distribution subsidiaries	—	185
Net realized and unrealized derivative (gains) losses	373	(318)
Depreciation, depletion and amortization	1,244	1,296
Deferred income taxes and investment tax credits, net	(1,670)	417
Other adjustments to income, net	10	(87)
Changes in:		
Accounts receivable	766	1,042
Inventories	(15)	(143)
Deferred fuel and purchased gas costs, net	(164)	231
Accounts payable	(631)	(656)
Accrued taxes	2,880	249
Deferred revenues	(71)	(203)
Margin deposit assets and liabilities	(79)	(26)
Other operating assets and liabilities	184	61
Net cash provided by operating activities	2,283	3,486
Investing Activities		
Plant construction and other property additions	(1,449)	(1,365)
Additions to gas and oil properties, including acquisitions	(1,788)	(1,509)
Net proceeds from sale of merchant generation facilities	339	—
Net proceeds from sale of non-Appalachian E&P business[1]	13,706	—
Proceeds from sale of securities and loan receivable collections and payoffs	968	750
Purchases of securities and loan receivable originations	(1,030)	(808)
Other	68	152
Net cash provided by (used in) investing activities	10,814	(2,780)
Financing Activities		
Repayment of short-term debt, net	(2,332)	(1,386)
Issuance of long-term debt	1,235	1,800
Repayment of long-term debt, including redemption premiums	(4,984)	(835)
Repayment of affiliated notes payable	(440)	—
Issuance of common stock	193	435
Repurchase of common stock	(5,763)	—
Common dividend payments	(704)	(727)
Other	27	(11)
Net cash used in financing activities	(12,768)	(724)
Increase (decrease) in cash and cash equivalents	329	(18)
Cash and cash equivalents at beginning of period[2]	142	146
Cash and cash equivalents at end of period[3]	$ 471	$ 128
Noncash Investing and Financing Activities:		
Accrued capital expenditures	$ 56	$ 218
Proceeds held in escrow from sale of Canadian E&P operations	156	—
Issuance of long-term debt and establishment of trust	—	47

(1) Excludes $156 million of proceeds held in escrow from the sale of our Canadian E&P operations.
(2) 2007 amount includes $4 million of cash classified as held for sale in our Consolidated Balance Sheet.
(3) 2007 and 2006 amounts include $2 million of cash classified as held for sale in our Consolidated Balance Sheets.

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

DOMINION RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1. Nature of Operations

Dominion Resources, Inc. (Dominion), headquartered in Richmond, Virginia, is one of the nation's largest producers and transporters of energy, with a portfolio of more than 26,500 megawatts (Mw) of generation, 7,800 miles of natural gas transmission pipeline and 1 trillion cubic feet equivalent (Tcfe) of natural gas and oil reserves. Dominion also owns and operates the nation's largest underground natural gas storage system with about 960 billion cubic feet (bcf) of storage capacity and serves retail energy customers in 11 states. On June 30, 2007, we merged our wholly-owned subsidiary, Consolidated Natural Gas Company (CNG), with our holding company, Dominion. As a result of the merger, all of CNG's subsidiaries became direct subsidiaries of Dominion.

As of September 30, 2007, we have sold all of our non-Appalachian natural gas and oil exploration and production (E&P) operations. We chose to retain our Appalachian assets due to their strategic fit with our natural gas transmission and storage assets. These transactions are discussed in Note 6.

Following the sale of our non-Appalachian E&P operations, our principal subsidiaries are Virginia Electric and Power Company (Virginia Power), Dominion Energy, Inc. (DEI), Dominion Transmission, Inc. (DTI) and Virginia Power Energy Marketing, Inc. (VPEM).

Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. As of September 30, 2007, Virginia Power served approximately 2.4 million retail customer accounts, including governmental agencies, as well as wholesale customers such as rural electric cooperatives and municipalities. Virginia Power is a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), and its electric transmission facilities are integrated into the PJM wholesale electricity markets.

DEI is involved in merchant generation, energy marketing and price risk management activities and natural gas exploration and production in the Appalachian basin of the United States (U.S.).

DTI operates a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, Mid-Atlantic and Midwest states and is engaged in the production, gathering and extraction of natural gas in the Appalachian basin.

VPEM provides fuel, gas supply management and price risk management services to other Dominion affiliates and engages in energy trading activities.

We have additional subsidiaries that operate in the natural gas business, including a variety of energy marketing services. As of September 30, 2007, our regulated gas distribution subsidiaries served approximately 1.7 million residential, commercial and industrial gas sales and transportation customer accounts in Ohio, Pennsylvania and West Virginia and our nonregulated retail energy marketing businesses served approximately 1.6 million residential and commercial customer accounts in the Northeast, Mid-Atlantic and Midwest regions of the U.S. We also operate a liquefied natural gas (LNG) import and storage facility in Maryland. Our producer services operations involve the aggregation of natural gas supply and related wholesale activities.

We have substantially exited the core operating businesses of Dominion Capital, Inc. (DCI) whose primary business was financial services, including loan administration, commercial lending and residential mortgage lending. Refer to Note 16 for information on a third-party collateralized debt obligation (CDO) entity that we consolidate in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R).

We manage our daily operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion E&P. In addition, we report a Corporate segment that includes our corporate, service company and other functions. Our assets remain wholly owned by us and our legal subsidiaries.

In the fourth quarter of 2007, we will realign our business units to reflect our strategic refocusing and begin managing our daily operations through three primary operating segments: Dominion Virginia Power (DVP), Dominion Generation and Dominion Energy. DVP will include our regulated electric distribution and electric transmission operations in

Virginia and North Carolina, as well as our nonregulated retail energy marketing and customer service operations. Dominion Generation will continue to include our regulated and merchant power generation. Dominion Energy will include our regulated natural gas distribution, transmission, storage and LNG operations, Appalachian-based natural gas and oil E&P operations and producer services.

The terms "Dominion," "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, Dominion Resources, Inc., one of Dominion Resources, Inc.'s consolidated subsidiaries or operating segments, or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries.

Note 2. Significant Accounting Policies

As permitted by the rules and regulations of the Securities and Exchange Commission (SEC), our accompanying unaudited Consolidated Financial Statements contain certain condensed financial information and exclude certain footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). These unaudited Consolidated Financial Statements should be read in conjunction with our Consolidated Financial Statements and Notes in our Annual Report on Form 10-K for the year ended December 31, 2006 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007.

In our opinion, the accompanying unaudited Consolidated Financial Statements contain all adjustments, including normal recurring accruals, necessary to present fairly our financial position as of September 30, 2007, our results of operations for the three and nine months ended September 30, 2007 and 2006, and our cash flows for the nine months ended September 30, 2007 and 2006.

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 revenues and expenses for the periods presented. Actual results may differ from those estimates.

Our accompanying unaudited Consolidated Financial Statements include, after eliminating intercompany transactions and balances, our accounts and those of our majority-owned subsidiaries and those variable interest entities (VIEs) where we have been determined to be the primary beneficiary.

In accordance with GAAP, we report certain contracts and instruments at fair value. Market pricing and indicative price information from external sources are used to measure fair value when available. In the absence of this information, we estimate fair value based on near-term and historical price information and statistical methods. For individual contracts, the use of differing assumptions could have a material effect on the contract's estimated fair value. See Note 2 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006 for a more detailed discussion of our estimation techniques.

The results of operations for interim periods are not necessarily indicative of the results expected for the full year. Information for quarterly periods is affected by seasonal variations in sales, rate changes, electric fuel and energy purchases, purchased gas expenses and other factors.

Certain amounts in our 2006 Consolidated Financial Statements and Notes have been recast to conform to the 2007 presentation.

As discussed further in Note 5, we reapplied the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71), to the Virginia jurisdiction of our utility generation operations upon enactment of reregulation legislation in Virginia on April 4, 2007. In connection with the reapplication of SFAS No. 71 to these operations, we prospectively changed certain of our accounting policies to those used by cost-of-service rate-regulated entities.

Under amendments to the Virginia fuel cost recovery statute passed in 2004, the fuel factor provisions for our electric utility were frozen until July 1, 2007. 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 instituted beginning July 1, 2007.

Note 3. Newly Adopted Accounting Standards

FIN 48

We adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), on January 1, 2007. As a result of the implementation of FIN 48, we recorded a $58 million charge to beginning retained earnings, representing the cumulative effect of the change in accounting principle.

Unrecognized tax benefits represent those tax benefits related to tax positions that have been taken or are expected to be taken in tax returns, including refund claims, that are not recognized in the financial statements because, in accordance with FIN 48, management has either measured the tax benefit at an amount less than the benefit claimed, or expected to be claimed, or concluded that it is not more-likely-than-not that the tax position will be ultimately sustained. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of an income tax refund receivable, an increase in deferred tax liabilities, or a decrease in deferred tax assets. Noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities; current payables are included in other current liabilities, except when such amounts are presented net with amounts receivable from or amounts prepaid to taxing authorities in other current assets.

In May 2007, the FASB issued FASB Staff Position No. FIN 48-1, *Definition of Settlement in FASB Interpretation No. 48* (FSP FIN 48-1), to provide guidance on how to determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. In light of its delayed issuance, if an enterprise did not implement FIN 48 in a manner consistent with the provisions of FSP FIN 48-1, it is required to retrospectively apply its provisions to the date of its initial adoption of FIN 48. In our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, we reported that our unrecognized tax benefits totaled $642 million as of January 1, 2007. In accordance with FSP FIN 48-1, we have reduced our January 1, 2007 balance of unrecognized benefits to $625 million to adjust for effectively settled tax positions.

For the nine months ended September 30, 2007, the activity for unrecognized tax benefits for tax positions taken in prior years included gross increases of $60 million and reductions of $51 million due to settlements with taxing authorities. The activity for unrecognized tax benefits for tax positions taken in the current year included gross increases of $47 million and gross decreases of $26 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. Unrecognized tax benefits also include amounts, for which uncertainty exists as to whether such amounts are deductible as ordinary deductions or capital losses. As discussed further in Note 6, we have sold all of our non-Appalachian E&P operations and assets. With the realization of gains from the non-Appalachian E&P sales, these prior year losses, if ultimately determined to be capital losses, would be deductible in 2007. 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 could otherwise be taken. Pending resolution of these timing uncertainties, interest is being accrued from the due date of prior years' returns until the period in which the amounts would be deductible, if not deducted in prior years. Through the nine months ended September 30, 2007, unrecognized tax benefits for prior periods have been reduced by $248 million to recognize amounts that, if not deducted in prior years, would be deductible in 2007. Over the next twelve months, unrecognized tax benefits could be reduced by an additional $16 million to recognize prior period amounts becoming otherwise deductible in the current period.

Unrecognized tax benefits as of January 1, 2007, included $76 million that, if recognized, would lower the effective tax rate. For the nine months ended September 30, 2007, the activity for such unrecognized tax benefits related to tax positions taken in the current year included gross decreases of $17 million and gross increases of $31 million.

Consistent with our existing policies, we continue to recognize estimated interest payable on underpayments of income taxes in interest expense and estimated penalties that may result from the settlement of some uncertain tax positions in other income. As of January 1, 2007, we had accrued approximately $9 million for interest and penalties.

We file a consolidated U.S. federal income tax return for Dominion and its subsidiaries. In addition, where applicable, we file combined income tax returns for Dominion and its subsidiaries in various states; otherwise, we file separate income tax returns for our subsidiaries in various states. We also filed federal and provincial income tax returns for certain former subsidiaries in Canada.

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 claim certain 1998 tax credits and also have reserved the right to pursue a refund of amounts related to interest costs capitalized on plant and equipment during the years 1995 through 1998. For CNG and its former subsidiaries, tax years prior to Dominion's acquisition of CNG in January 2000 are no longer subject to examination, except for amended returns filed in June 2007 for tax years 1996, 1997 and 1998, claiming refunds for certain tax credits.

The U.S. Congressional Joint Committee on Taxation has recently completed its review of our settlement for tax years 1993 through 1998 with the Appellate Division of the Internal Revenue Service (IRS). As a result, we will receive a tax refund of approximately $42 million. Receipt of this refund will not impact our results of operations. We are also currently engaged in settlement negotiations with the Appellate Division of the IRS regarding certain adjustments proposed during the examination of tax years 1999 through 2001. Settlement negotiations could possibly conclude later this year. In addition, the IRS recently completed its examination of our 2002 and 2003 consolidated returns and the 2002 and 2003 returns of certain affiliate partnerships. We filed protests for certain proposed adjustments with the Appellate Division of the IRS in July and October 2007.

We have filed appeals of assessments received from taxing authorities, and we believe that it is reasonably possible that, based on settlement negotiations, unrecognized tax benefits could decrease by up to $77 million over the next twelve months.

For major states in which we operate, the earliest tax year remaining open for examination is as follows:

State	Earliest Open Tax Year
Pennsylvania	2000
Connecticut	2001
Virginia	2003
Massachusetts	2003

We are also obligated to report adjustments resulting from IRS settlements to state taxing authorities. In addition, if we utilize state net operating losses or tax credits generated in years for which the statute of limitations has expired, the determination of such amounts is subject to examination.

EITF 04-13

Prior to the sale of our non-Appalachian E&P business, we entered into buy/sell and related agreements primarily as a means to reposition our offshore Gulf of Mexico crude oil production to more liquid marketing locations onshore and to facilitate gas transportation. In September 2005, the FASB ratified the Emerging Issues Task Force's (EITF) consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (EITF 04-13), that requires buy/sell and related agreements to be presented on a net basis in the Consolidated Statements of Income if they are entered into in contemplation of one another. We adopted the provisions of EITF 04-13 on April 1, 2006 for new arrangements entered into, and modifications or renewals of existing arrangements after that date. As a result, a significant portion of our activity related to buy/sell arrangements is presented on a net basis in our Consolidated Statement of Income for the three months and nine months ended September 30, 2007; however, there was no impact on our results of operations or cash flows. Pursuant to the transition provisions of EITF 04-13, activity related to buy/sell arrangements that were entered into prior to April 1, 2006 and have not been modified or renewed after that date continue to be reported on a gross basis and are included in the activity summarized below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(millions)				
Sale activity included in operating revenue	$8	$ 37	$ 67	$ 543
Purchase activity included in operating expenses[(1)]	8	39	70	539

(1) Included in other energy-related commodity purchases expense and purchased gas expense on our Consolidated Statements of Income.

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 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. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157), which defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability and establishes a fair value hierarchy of three levels that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data. SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy. The provisions of SFAS No. 157 will become effective for us beginning January 1, 2008. Generally, the provisions of this statement are to be 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 is required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses under EITF Issue 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*. We are currently evaluating the impact that SFAS No. 157 will have on our results of operations and financial condition.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159). 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. The provisions of SFAS No. 159 will become effective for us beginning January 1, 2008. We are currently evaluating the impact that SFAS No. 159 may have on our results of operations and financial condition.

EITF 06-4

In September 2006, the FASB ratified the consensus reached by the EITF on Issue No. 06-4, *Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements* (EITF 06-4). EITF 06-4 specifies that if an employer provides a benefit to an employee under an endorsement split-dollar life insurance arrangement that extends to postretirement periods, it should recognize a liability for future benefits in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (if, in substance, a postretirement benefit plan exists) or Accounting Principles Board Opinion No. 12, *Deferred Compensation Contracts* (if the arrangement is, in substance, an individual deferred compensation contract) based on the substantive agreement with the employee. We have certain insurance policies subject to the provisions of EITF 06-4 and are currently evaluating the impact that EITF 06-4 may have on our results of operations and financial condition. The provisions of EITF 06-4 will become effective for us beginning January 1, 2008.

EITF 06-11

In June 2007, the FASB ratified the consensus reached by the EITF on Issue No. 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards* (EITF 06-11). EITF 06-11 addresses the recognition of income tax benefits realized from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for nonvested equity-classified share-based payment awards. Effective January 1, 2008, we will recognize such income tax benefits as an increase to additional paid-in capital rather than as a reduction to income tax expense. We do not expect EITF 06-11 to have a material impact on our results of operations or financial condition.

FSP FIN 39-1

In April 2007, the FASB issued FASB Staff Position No. FIN 39-1, *Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts* (FSP FIN 39-1). 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 that have been offset. FSP FIN 39-1 will become effective for us beginning January 1, 2008 and must be applied retroactively to all financial statements presented, unless it is impracticable to do so. We are currently evaluating the impact that FSP FIN 39-1 may have on our financial condition. We do not expect FSP FIN 39-1 to have an impact on our results of operations or cash flows.

Note 5. Reapplication of SFAS No. 71

In March 1999, we discontinued the application of SFAS No. 71 to the majority of our utility generation operations upon the enactment of deregulation legislation in Virginia. Our utility 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 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 accounting impacts of the reapplication of SFAS No. 71 are described below.

Extraordinary Item

The reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility 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 accumulated other comprehensive income (AOCI). This was done in order to establish a \$454 million long-term regulatory liability for amounts 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* (SFAS No. 143).

Pension and Other Postretirement Benefits

Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, we reclassified \$110 million (\$67 million after tax) of pension and other postretirement benefit costs attributable to those operations previously recorded in AOCI to a regulatory asset. These costs represent net unrecognized actuarial (gains) losses, unrecognized prior service cost (credit) and unrecognized transition obligation remaining from our initial adoption of SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, that will be recognized as a component of future net periodic benefit cost based on our historical accounting policy for amortizing such amounts and are expected to be recovered through future rates.

Accounting Policy Changes

In connection with the reapplication of SFAS No. 71, we prospectively changed certain of our accounting policies for the Virginia jurisdiction of our utility generation operations to those used by cost-of-service rate-regulated entities. Other than the extraordinary item discussed above, the overall impact of these changes, summarized below, was not material to our results of operations or financial condition.

Utility Nuclear Decommissioning Trust Funds

Net realized and unrealized gains and losses are now recorded to the regulatory liability established upon reapplication of SFAS No. 71 as described above. Previously, realized gains and losses and any other-than-temporary declines in fair value were included in other income and unrealized gains were reported as a component of AOCI, net of tax.

Property, Plant and Equipment

Early retirements of generation-related utility property are now recorded to accumulated depreciation rather than recognizing gains and losses upon retirement. Cost of removal incurred or salvage proceeds realized in connection with a retirement of utility generation property, plant and equipment is now recorded to accumulated depreciation rather than being charged to expense as incurred. We discontinued capitalizing interest on all utility generation construction projects since the Virginia State Corporation Commission (Virginia Commission) previously allowed for current recovery of construction financing costs.

Asset Retirement Obligations (ARO)

Accretion and depreciation associated with utility nuclear decommissioning AROs, previously charged to expense, are now recorded as a reduction to the regulatory liability for nuclear decommissioning trust funds discussed above, in order to match the recognition for rate-making purposes.

Derivative Instruments

Previously, unrealized gains and losses resulting from changes in the fair value of derivative instruments designated as cash flow or fair value hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), were recorded in AOCI, or long-term debt, respectively. Also, ineffectiveness and gains and losses excluded from the measurement of ineffectiveness, were recorded through earnings as incurred. Following the reapplication of SFAS No. 71, for jurisdictions subject to cost-based regulation, changes in the fair value of these derivative instruments will be classified as regulatory assets or regulatory liabilities as these instruments now receive regulatory treatment. Gains or losses on the derivative instruments will generally be recognized when the related transactions impact net income.

Note 6. Dispositions

Sale of Non-Appalachian Natural Gas and Oil E&P Operations and Assets

We have completed the sale of our non-Appalachian natural gas and oil E&P operations and assets for approximately $13.9 billion. At December 31, 2006, our non-Appalachian natural gas and oil assets included about 5.5 Tcfe of proved reserves. The Appalachian assets that we have retained included about 1 Tcfe of proved reserves at December 31, 2006.

Due to the sale of our entire Canadian cost pool, the results of operations for our Canadian E&P business are reported as discontinued operations in our Consolidated Statements of Income. The results of operations for our U.S. non-Appalachian E&P business are not reported as discontinued operations in our Consolidated Statements of Income since we did not sell our entire U.S. cost pool, which includes the retained Appalachian assets.

We used most of the after-tax proceeds from these dispositions to reduce our outstanding debt and repurchase shares of our common stock. See Note 17 for a discussion of significant financing transactions.

The E&P operations we have sold are as follows:

Canadian Operations

On June 26, 2007, we completed the sale of our Canadian E&P operations to Paramount Energy Trust and Baytex Energy Trust for approximately $624 million, subject to post-closing adjustments. These operations included approximately 267 billion cubic feet equivalent (bcfe) of proved reserves in western Canada as of December 31, 2006. The sale resulted in an after-tax gain of $61 million ($0.17 per share). As required by the sale agreement, $156 million of the proceeds were held in escrow to ensure the payment of our Canadian tax obligation, resulting from the gain recognized on the sale. The funds were released from escrow in the fourth quarter of 2007 in exchange for a letter of credit. We expect to pay the tax related to the gain on the sale by the end of the second quarter of 2008.

The following table presents selected information regarding the results of operations of our Canadian E&P operations, which are reported as discontinued operations in our Consolidated Statements of Income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2007	2006	2007	2006
Operating revenue	$ —	$ 33	$ 82	$109
Income before income taxes	—	3	149(1)	18

(1) Amount includes pre-tax gain of $194 million recognized on the sale.

Offshore Operations

On July 2, 2007, we completed the sale of substantially all of our offshore E&P operations to Eni Petroleum Co. Inc. (Eni) for approximately $4.73 billion, subject to post-closing adjustments. Our offshore operations included approximately 967 bcfe of proved natural gas and oil reserves in the outer continental shelf and deepwater areas of the Gulf of Mexico at December 31, 2006. Of this total, approximately 961 bcfe were sold to Eni. Remaining offshore E&P operations were disposed of in a separate transaction in June 2007.

Certain Onshore Operations

On July 31, 2007, we completed the sale to HighMount Exploration & Production LLC, a newly formed subsidiary of Loews Corporation, of our E&P operations in the Alabama, Michigan and Permian basins for approximately $4.0 billion, subject to post-closing adjustments. These operations included approximately 2.5 Tcfe of proved natural gas and oil reserves at December 31, 2006.

Also on July 31, 2007, we completed the sale to XTO Energy Inc., of our E&P operations in the Gulf Coast, Rocky Mountains, South Louisiana and San Juan Basin of New Mexico for approximately $2.5 billion, subject to post-closing adjustments. These operations included approximately 1 Tcfe of proved natural gas and oil reserves at December 31, 2006.

On August 31, 2007, we completed the sale to Linn Energy, LLC, of our E&P operations in the Mid-Continent Basin for approximately $2.0 billion, subject to post-closing adjustments. These operations, located primarily in Oklahoma, included approximately 780 bcfe of proved natural gas and oil reserves at December 31, 2006.

Costs Associated with Disposal of Non-Appalachian E&P Operations

The sales of our U.S. non-Appalachian E&P operations resulted in the discontinuance of hedge accounting for certain cash flow hedges since it became probable that the forecasted sales of gas and oil will not occur. In connection with the discontinuance of hedge accounting for these contracts, we recognized charges, recorded in other operations and maintenance expense in our Consolidated Statement of Income, predominantly reflecting the reclassification of losses from AOCI to earnings and subsequent changes in fair value of these contracts of $544 million ($347 million after-tax) for the nine months ended September 30, 2007. We retained these gas and oil derivatives, but have entered into offsetting derivative contracts that will minimize the future volatility in earnings that may result from these contracts being marked to market. We recognized a similar charge of $15 million ($9 million after-tax) for the nine months ended September 30, 2007 related to our Canadian operations, which is reflected in discontinued operations in our Consolidated Statement of Income.

During the nine months ended September 30, 2007, we also recorded a charge of approximately $171 million ($108 million after-tax) for the recognition of certain forward gas contracts that previously qualified for the normal purchase and sales exemption under SFAS No. 133. The $171 million charge includes $139 million associated with volumetric production payment (VPP) agreements to which we were a party. We paid $250 million to terminate the VPP agreements and are retaining the repurchased fixed-term overriding royalty interests formerly associated with these agreements.

Additionally, we recognized expenses for employee severance, retention and other costs of $77 million ($48 million after-tax) for the nine months ended September 30, 2007, related to the sale of our U.S. non-Appalachian E&P business, which are reflected in other operations and maintenance expense in our Consolidated Statement of Income. We also recognized expenses for employee severance, retention, legal, investment banking and other costs of $30 million ($18 million after-tax) for the nine months ended September 30, 2007 related to the sale of our Canadian E&P operations, which are reflected in discontinued operations in our Consolidated Statement of Income.

We recognized a gain of approximately $3.6 billion ($2.1 billion after-tax) from the disposition of our U.S. non-Appalachian E&P operations. This gain is net of expenses related to the disposition plan for transaction costs, including audit, legal, investment banking and other costs of $47 million ($29 million after-tax), but excludes severance and retention costs and costs associated with the discontinuance of hedge accounting and recognition of forward gas contracts. We expect to pay the federal income taxes related to the gain on the sale in the fourth quarter of 2007 and the related state income taxes by the end of the second quarter of 2008.

The total impact on net income from the sale of our Canadian and U.S. non-Appalachian E&P operations was $1.9 billion and $1.5 billion, respectively, for the three and nine months ended September 30, 2007. This benefit is net of expenses for transaction costs, severance and retention costs, costs associated with the discontinuance of hedge accounting and recognition of forward gas contracts, and costs associated with our debt tender offer completed in July 2007 using a portion of the proceeds received from the sale, as discussed in Note 17.

Disposition of Partially Completed Generation Facility

In September 2007, we completed the sale of the Dresden Energy merchant generation facility (Dresden) to AEP Generating Company (AEP) for $85 million. During the second quarter 2007, we recorded a $387 million ($252 million after-tax) impairment charge in other operations and maintenance expense to reduce Dresden's carrying amount to its estimated fair value based on AEP's purchase price.

Sale of Certain DCI Operations

In May 2007, we committed to a plan to dispose of certain DCI operations for $30 million. The sale includes substantially all of the assets of Gichner LLC (Gichner), all of the issued and outstanding shares of the capital stock of Gichner, Inc. (an affiliate of Gichner), as well as all of the membership interests in Dallastown Realty (Dallastown). Gichner designs, manufactures, integrates, markets, distributes, sells and services tactical and logistic shelters and related products for military commercial applications. Dallastown owns the land and buildings in which Gichner conducts its principal operations in the U.S.

The consideration to be received indicated that the goodwill associated with these operations was impaired and in June 2007, we recorded a goodwill impairment charge in other operations and maintenance expense in our Consolidated Statement of Income of $8 million related to the DCI reporting unit. In August 2007, we completed the sale of Gichner and Dallastown for approximately $30 million. The sale resulted in an after-tax loss of $4 million ($0.01 per share), which included the allocation of $10 million of Corporate reporting unit goodwill to the bases of the investments sold.

The following table presents selected information regarding the results of operations of Gichner and Dallastown, which are reported as discontinued operations in our Consolidated Statements of Income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(millions)				
Operating revenue	$ 7	$ 9	$ 29	$ 31
Income (loss) before income taxes	(1)	—	(7)	2

Sale of Merchant Generation Facilities

In March 2007, we sold three of our natural gas-fired merchant generation peaking facilities (Peaker facilities) for net cash proceeds of $254 million. The sale resulted in a $24 million after-tax loss ($0.07 per share). The Peaker facilities are:

- Armstrong, a 625 Mw station in Shelocta, Pennsylvania;
- Troy, a 600 Mw station in Luckey, Ohio; and
- Pleasants, a 313 Mw station in St. Mary's, West Virginia.

The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheet at December 31, 2006 were comprised of property, plant and equipment, net ($245 million), inventory ($13 million) and accounts payable ($3 million).

The following table presents selected information regarding the results of operations of the Peaker facilities, which are reported as discontinued operations in our Consolidated Statements of Income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(millions)				
Operating revenue	$ —	$ 19	$ 5	$ 33
Loss before income taxes	—	(6)	(31) [(1)]	(23)

(1) Amount includes pre-tax loss of $25 million recognized on the sale, resulting largely from the allocation of $24 million of Generation reporting unit goodwill to the bases of the investments sold.

Sale of Regulated Gas Distribution Subsidiaries

On March 1, 2006, we entered into an agreement with Equitable Resources, Inc., to sell two of our wholly-owned regulated gas distribution subsidiaries, The Peoples Natural Gas Company (Peoples) and Hope Gas, Inc. (Hope), for approximately $970 million plus adjustments to reflect capital expenditures and changes in working capital. Peoples and Hope serve approximately 500,000 customer accounts in Pennsylvania and West Virginia. The transaction is subject to regulatory approval, as discussed in *Future Issues and Other Matters* in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations. The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheets are as follows:

(millions)	September 30, 2007	December 31, 2006
ASSETS		
Current Assets		
Customer receivables	$ 69	$ 144
Other	137	125
Total current assets	206	269
Property, Plant and Equipment		
Property, plant and equipment	1,150	1,129
Accumulated depreciation, depletion and amortization	(370)	(375)
Total property, plant and equipment, net	780	754
Deferred Charges and Other Assets		
Regulatory assets	108	106
Other	2	4
Total deferred charges and other assets	110	110
Assets held for sale	$ 1,096	$ 1,133
LIABILITIES		
Current Liabilities	$ 151	$ 236
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	190	187
Other	73	71
Total deferred credits and other liabilities	263	258
Liabilities held for sale	$ 414	$ 494

The following table presents selected information regarding the results of operations of Peoples and Hope:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2007	2006	2007	2006
Operating revenue	$ 62	$ 63	$479	$ 512
Income (loss) before income taxes	(6)	(6)	49	(134)

In the nine months ended September 30, 2006, we recognized a $167 million ($103 million after-tax) charge, recorded in other operations and maintenance expense in our Consolidated Statement of Income, resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, since the recovery of those assets is no longer probable. At September 30, 2007, our Consolidated Balance Sheet reflects $134 million of deferred tax liabilities, which were recorded in accordance with EITF Issue No. 93-17, *Recognition of Deferred Tax Assets for a Parent Company's Excess Tax Basis in the Stock of a Subsidiary that is Accounted for as a Discontinued Operation* (EITF 93-17). Although these subsidiaries are not classified as discontinued operations, EITF 93-17 requires that the deferred tax impact of the excess of the financial reporting basis over the tax basis of a parent's investment in a subsidiary be recognized when it is apparent that this difference will reverse in the foreseeable future. We recorded these deferred tax liabilities, since the financial reporting basis of our investment in Peoples and Hope exceeded our tax basis. This difference and related deferred taxes will reverse and will partially offset current tax expense recognized upon closing of the sale.

Note 7.Pro Forma Financial Statements

The accompanying unaudited Pro Forma Condensed Consolidated Statements of Income for the nine months ended September 30, 2007 and for the year ended December 31, 2006, reflect the disposition of our non-Appalachian E&P operations as if it had occurred on January 1, 2007 and 2006, respectively.

The pro forma adjustments have been based on the operations of our non-Appalachian E&P operations during the periods presented, the impact of the disposition of these operations and other transactions resulting from the disposition. The pro forma adjustments have been made to illustrate the anticipated financial impact of the disposition upon Dominion and are based upon available information and assumptions that we believe to be reasonable at the date of this filing. Consequently, the pro forma financial information presented is not necessarily indicative of the consolidated results of operations that would have been reported had the transaction actually occurred on the dates presented. Moreover, the pro forma financial information does not purport to indicate the future results that Dominion will experience.

PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME
Nine Months Ended September 30, 2007
(Unaudited)

(millions, except per share amounts)	As Reported	Less: E&P Dispositions	Pro Forma Adjustments	Pro Forma Results
Operating Revenue	$ 11,980	$ 1,351	$ —	$ 10,629
Operating Expenses				
Electric fuel and energy purchases	2,742	—	—	2,742
Purchased electric capacity	339	—	—	339
Purchased gas	2,024	50	—	1,974
Other energy-related commodity purchases	184	—	—	184
Other operations and maintenance	3,906	1,312	(8)[1]	2,586
Gain on sale of U.S. non-Appalachian E&P business	(3,602)	(3,602)	—	—
Depreciation, depletion and amortization	1,116	427	—	689
Other taxes	436	87	—	349
Total operating expenses	7,145	(1,726)	(8)	8,863
Income from operations	4,835	3,077	8	1,766
Other income	125	—	—	125
Interest and related charges	974	—	(153)[2]	
			(234)[1]	587
Income from continuing operations before income tax expense and minority interest	3,986	3,077	395	1,304
Income tax expense	1,576	1,481	153 [3]	248
Minority interest	7	—	—	7
Income from continuing operations	$ 2,403	$ 1,596	$ 242	$ 1,049
Earnings Per Share				
Income from continuing operations – Basic	$ 7.10			$ 3.61
Income from continuing operations – Diluted	$ 7.05			$ 3.58
Weighted average shares outstanding – Basic	338.4	—	(47.9)[4]	290.5
Weighted average shares outstanding – Diluted	340.6	—	(47.9)[4]	292.7

(1) Represents the removal of non-recurring expenses associated with the completion of our debt tender offer on July 12, 2007, using a portion of the proceeds from the disposition of our non-Appalachian E&P operations.

(2) Represents the prorated decrease in interest expense resulting from the repayment of $3.4 billion in debt with a portion of the proceeds from the disposition of our non-Appalachian E&P operations (disposition). This amount is comprised of $2.5 billion in long term debt retired in connection with our debt tender offer completed on July 12, 2007; $500 million of bank debt incurred at our CNG subsidiary which was repaid prior to the merger of that subsidiary with and into Dominion, effective June 30, 2007; $200 million of senior notes originally issued by our and CNG's subsidiary Dominion Oklahoma Texas Exploration & Production, Inc., which were redeemed on June 29, 2007 and $200 million of trust preferred securities originally issued by CNG, which were redeemed on July 17, 2007.

(3) Reflects the income tax effects of the pro forma adjustments associated with the disposition of our non-Appalachian E&P operations based on the weighted-average statutory rates for all jurisdictions that would have applied during the period.

(4) Reflects the prorated impact of our equity tender offer discussed in Note 17. We purchased approximately 57.8 million shares at a price of $91 per share, with a portion of the proceeds received from the disposition.

PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME

Year Ended December 31, 2006
(Unaudited)

(millions, except per share amounts)	As Reported(1)	Less: E&P Dispositions	Pro Forma Adjustments	Pro Forma Results
Operating Revenue	$ 16,296	$ 2,838	$ —	$ 13,458
Operating Expenses				
Electric fuel and energy purchases	3,236	—	—	3,236
Purchased electric capacity	481	—	—	481
Purchased gas	2,937	165	—	2,772
Other energy-related commodity purchases	1,022	409	—	613
Other operations and maintenance	3,177	352	—	2,825
Depreciation, depletion and amortization	1,557	695	—	862
Other taxes	568	125	—	443
Total operating expenses	12,978	1,746	—	11,232
Income from operations	3,318	1,092	—	2,226
Other income	173	—	—	173
Interest and related charges	1,028	—	(254)(2)	774
Income from continuing operations before income tax expense and minority interest	2,463	1,092	254	1,625
Income tax expense	927	417	99 (3)	609
Minority interest	6	—	—	6
Income from continuing operations	$ 1,530	$ 675	$ 155	$ 1,010
Earnings Per Share				
Income from continuing operations – Basic	$ 4.38			$ 3.46
Income from continuing operations – Diluted	$ 4.35			$ 3.44
Weighted average shares outstanding – Basic	349.7	—	(57.8)(4)	291.9
Weighted average shares outstanding – Diluted	351.6	—	(57.8)(4)	293.8

(1) Reflects the reclassification of Gichner, Dallastown and our Canadian E&P operations to discontinued operations.

(2) Represents the decrease in interest expense expected to result from the repayment of $3.4 billion in debt with a portion of the proceeds from the disposition of our non-Appalachian E&P operations. This amount is comprised of $2.5 billion in long term debt retired in connection with our debt tender offer completed on July 12, 2007; $500 million of bank debt incurred at our CNG subsidiary which was repaid prior to the merger of that subsidiary with and into Dominion, effective June 30, 2007; $200 million of senior notes originally issued by our and CNG's subsidiary Dominion Oklahoma Texas Exploration & Production, Inc., which were redeemed on June 29, 2007 and $200 million of trust preferred securities originally issued by CNG, which were redeemed on July 17, 2007.

(3) Reflects the income tax effects of the pro forma adjustments associated with the disposition of our non-Appalachian E&P operations based on the weighted-average statutory rates for all jurisdictions that would have applied during the period.

(4) Reflects the final results of our equity tender offer discussed in Note 17. We purchased approximately 57.8 million shares at a price of $91 per share, with a portion of the proceeds received from the disposition.

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NOTES TO CONDENSED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Nonrecurring items related to the dispositions

Certain nonrecurring items resulting from the disposition of our non-Appalachian E&P operations have not been reflected in the accompanying Condensed Pro Forma Consolidated Statements of Income. See *Costs Associated with Disposal of Non-Appalachian E&P Operations* in Note 6.

Note 8. Operating Revenue

Our operating revenue consists of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(millions)				
Operating Revenue				
Electric sales:				
Regulated	**$1,796**	$1,650	**$ 4,593**	$ 4,231
Nonregulated	**839**	623	**2,299**	1,760
Gas sales:				
Regulated	**86**	96	**829**	1,071
Nonregulated	**338**	382	**1,681**	1,638
Other energy-related commodity sales	**128**	253	**434**	1,156
Gas transportation and storage	**181**	190	**742**	676
Gas and oil production	**147**	446	**1,191**	1,401
Other	**74**	333	**211**	442
Total operating revenue	**$3,589**	$3,973	**$11,980**	$12,375

Note 9. Income Taxes

A reconciliation of income taxes at the U.S. statutory federal rate as compared to the income tax expense recorded for continuing operations in our Consolidated Statements of Income is presented below:

	Nine Months Ended September 30,	
	2007	2006
U.S. statutory rate	**35.0%**	35.0%
Increases (reductions) resulting from:		
Amortization of investment tax credits	**(0.2)**	(0.4)
Qualified production activities	**(0.5)**	—
Employee pension and other benefits	**(0.2)**	(0.3)
Employee stock ownership plan and restricted stock dividends	**(0.3)**	(0.5)
State taxes, net of federal benefit	**3.4**	5.1
Changes in valuation allowances	**(2.6)**	(9.1)
Goodwill	**5.2**	—
Recognition of deferred taxes – stock of subsidiaries held for sale	**(0.2)**	6.5
Other, net	**(0.1)**	(0.4)
Effective tax rate	**39.5%**	35.9%

Our estimated 2007 annual effective tax rate reflects the effects of the sale of our non-Appalachian E&P operations, including the impact of goodwill, not deductible for tax purposes, that reduced the book gain on sale. A tax benefit has been recognized from the elimination of $126 million of valuation allowances on deferred tax assets that relate to federal and state loss carryforwards, since these carryforwards will be utilized to offset gains from the sale. As the result of changes in state apportionment following the sale, our future effective state tax rate is expected to be higher for ongoing operations.

In 2006, the effective tax rate reflected the net tax benefit from changes in valuation allowances on deferred tax assets, including a $222 million reduction related to federal and state tax loss carryforwards then expected to be utilized to offset capital gain income anticipated from the pending sale of Peoples and Hope, offset by a $38 million increase in the second quarter related to the impairment of certain DCI investments. The net benefit was partially offset by the establishment of $136 million of deferred tax liabilities, in 2006, associated with the excess of our financial reporting basis over our tax basis in the stock of Peoples and Hope, in accordance with EITF 93-17.

Note 10. Earnings Per Share

The following table presents the calculation of our basic and diluted EPS:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
(millions, except EPS)				
Income from continuing operations before extraordinary item	**$2,320**	$ 655	**$2,403**	$1,335
Extraordinary item	**—**	—	**(158)**	—
Income (loss) from discontinued operations	**(3)**	(1)	**(5)**	14
Net income	**$2,317**	$ 654	**$2,240**	$1,349
Basic EPS				
Average shares of common stock outstanding – basic	**317.8**	351.9	**338.4**	349.1
Income from continuing operations before extraordinary item	**$ 7.30**	$ 1.86	**$ 7.10**	$ 3.82
Extraordinary item	**—**	—	**(0.47)**	—
Income (loss) from discontinued operations	**(0.01)**	—	**(0.01)**	0.04
Net income	**$ 7.29**	$ 1.86	**$ 6.62**	$ 3.86
Diluted EPS				
Average shares of common stock outstanding	**317.8**	351.9	**338.4**	349.1
Net effect of potentially dilutive securities[1]	**2.0**	2.0	**2.2**	1.8
Average shares of common stock outstanding – diluted	**319.8**	353.9	**340.6**	350.9
Income from continuing operations before extraordinary item	**$ 7.25**	$ 1.85	**$ 7.05**	$ 3.80
Extraordinary item	**—**	—	**(0.46)**	—
Income (loss) from discontinued operations	**(0.01)**	—	**(0.01)**	0.04
Net income	**$ 7.24**	$ 1.85	**$ 6.58**	$ 3.84

(1) Potentially dilutive securities consist of options, restricted stock, equity-linked securities and contingently convertible senior notes.

Potentially dilutive securities with the right to acquire approximately 1 million common shares for the nine months ended September 30, 2006 were not included in the respective period's calculation of diluted EPS because the exercise or purchase prices of those instruments were greater than the average market price of our common shares. There were no such anti-dilutive securities outstanding during the three months ended September 30, 2006 or the three or nine months ended September 30, 2007.

Common Stock Split

On October 26, 2007, our board of directors approved a two-for-one stock split and an increase in the number of shares of common stock the Company is authorized to issue from 500 million to 1 billion. Shareholders of record on November 9, 2007, will receive one additional share of common stock for each share held at the close of business on that date; however, the proportionate interest that a shareholder owns in the Company will not change as a result of the stock split. The additional shares will be distributed on or after November 19, 2007. Based on shares outstanding at September 30, 2007, upon the completion of the stock split Dominion will have approximately 575 million shares of common stock outstanding. The stock split will require us to recast all of our historical shares and per share data in the fourth quarter of 2007.

Note 11. Goodwill

The changes in the carrying amount of goodwill during the nine months ended September 30, 2007 are presented below:

(millions)	Dominion Generation	Dominion Energy	Dominion Delivery	Dominion E&P	Corporate	Total
Balance at December 31, 2006	$ 1,479	$ 740	$ 1,184	$ 877	$ 18	$4,298
Sale of non-Appalachian E&P business	—	—	—	(760)		(760)
Sale of Peaker facilities	(24)	—	—	—	—	(24)
Sale of Gichner and Dallastown	—	—	—	—	(18)	(18)
Balance at September 30, 2007	$ 1,455	$ 740	$ 1,184	$ 117	$ —	$3,496

Note 12. Comprehensive Income

The following table presents total comprehensive income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2007	2006	2007	2006
Net income	$2,317	$ 654	$2,240	$ 1,349
Other comprehensive income (loss):				
Net other comprehensive income associated with effective portion of changes in fair value of derivatives designated as cash flow hedges, net of taxes and amounts reclassified to earnings	104	888 (1)	428 (2)	2,011 (1)
Other	18 (3)	70 (4)	(52) (5)	59 (4)
Other comprehensive income	122	958	376	2,070
Total comprehensive income	$2,439	$1,612	$2,616	$ 3,419

(1) Largely due to the settlement of certain commodity derivative contracts and favorable changes in fair value, primarily resulting from a decrease in electricity and gas prices.
(2) Principally due to the de-designation of certain E&P cash flow hedges, in connection with the sales of our non-Appalachian E&P operations.
(3) Primarily reflects the recognition of certain pension-related amounts as a component of net periodic benefit cost that were previously deferred in AOCI.
(4) Primarily represents the impact of net unrealized gains on investments held in nuclear decommissioning trusts and foreign currency translation adjustments.
(5) Primarily reflects the impact of foreign currency translation adjustments due to the sale of our Canadian E&P operations and the reclassification of pension-related amounts and unrealized gains on investments held in nuclear decommissioning trusts, both associated with the Virginia jurisdiction of our utility generation operations, previously recorded in AOCI to regulatory assets and regulatory liabilities, respectively, as a result of the reapplication of SFAS No. 71 to those operations.

Note 13. Hedge Accounting Activities

We are exposed to the impact of market fluctuations in the price of electricity, natural gas, oil and other energy-related products marketed and purchased, as well as currency exchange and interest rate risks of our business operations. We use derivative instruments to manage our exposure to these risks and designate certain derivative instruments as fair value or cash flow hedges for accounting purposes as allowed by SFAS No. 133. Selected information about our hedge accounting activities follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(millions)				
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:				
Fair value hedges	$3	$(15)	$ 5	$ (23)
Cash flow hedges	4	9	47	33
Net ineffectiveness	$7	$ (6)	$ 52	$ 10

For the three months and nine months ended September 30, 2007 and 2006, amounts excluded from the measurement of effectiveness did not have a significant impact on net income.

See Note 6 for a discussion of the discontinuance of hedge accounting for gas and oil hedges during the nine months ended September 30, 2007.

In the third quarter of 2007, we determined that, as a result of the expected termination of the long-term power sales agreement associated with our 515 Mw State Line power station (State Line), this agreement no longer qualifies for the normal purchase and normal sale exception allowed under SFAS No. 133. As part of the termination transaction, we will pay approximately $233 million primarily in exchange for the termination of the power sales agreement, acquisition of coal inventory and assignment of certain coal supply, transportation and railcar lease contracts. The normal purchase and normal sale exception must be discontinued if it is no longer probable that physical delivery of power will continue to occur throughout the term of the power sales agreement. As a result of the discontinuance of the normal purchase and normal sale exception, we recorded a $236 million ($140 million after-tax) charge included in other operations and maintenance expense in our Consolidated Statement of Income. The transaction closed in October 2007.

The following table presents selected information related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at September 30, 2007:

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
(millions)			
Commodities:			
Gas	$ 19	$ 6	41 months
Electricity	12	6	65 months
Other	(2)	(4)	32 months
Interest rate	(27)	(4)	225 months
Foreign currency	4	2	44 months
Total	$ 6	$ 6	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) 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 14. Ceiling Test

We follow the full cost method of accounting for gas and oil E&P activities prescribed by the SEC. Under the full cost method, capitalized costs are subject to a quarterly ceiling test. Under the ceiling test, amounts capitalized are limited to the present value of estimated future net revenues to be derived from the anticipated production of proved gas and oil reserves, assuming period-end hedge-adjusted prices.

Approximately 7% of the anticipated production from our Appalachian operations and fixed-term overriding royalty interests formerly associated with the VPP agreements is hedged by qualifying cash flow hedges, for which hedge-adjusted prices were used to calculate estimated future net revenue. Whether period-end market prices or hedge-adjusted prices were used for the portion of production that is hedged, there was no ceiling test impairment as of September 30, 2007.

Note 15. Asset Retirement Obligations

The following table describes the changes to our AROs during the nine months ended September 30, 2007:

(millions)	Amount
Asset retirement obligations at December 31, 2006[1]	$ 1,932
Obligations incurred during the period	17
Obligations settled during the period	(30)
Obligations relieved due to sale of non-Appalachian E&P business	(275)
Accretion	74
Revisions in estimated cash flows	(2)
Asset retirement obligations at September 30, 2007[1]	$1,716

(1) Includes $2 million and $1 million reported in other current liabilities at December 31, 2006 and September 30, 2007, respectively.

Note 16. Variable Interest Entities

Certain variable pricing terms in some of our long-term power and capacity contracts cause them to be considered potential variable interests in the counterparties. As discussed in Note 16 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, two potential VIEs, with which we have existing power purchase agreements (signed prior to December 31, 2003), had not provided sufficient information for us to perform our evaluation under FIN 46R.

As of September 30, 2007, limited information has been received from the two remaining potential VIEs. We will continue our efforts to obtain information and will complete an evaluation of our relationship with each of these potential VIEs if sufficient information is ultimately obtained. We have remaining purchase commitments with these two potential VIE supplier entities of $1.2 billion at September 30, 2007. We are not subject to any risk of loss from these potential VIEs, other than the remaining purchase commitments. We paid $24 million for electric generation capacity from these entities in the three months ended September 30, 2007 and 2006. We paid $34 million and $31 million for electric energy from these entities in the three months ended September 30, 2007 and 2006, respectively. We paid $74 million and $72 million for electric generation capacity and $84 million and $68 million for electric energy from these entities in the nine months ended September 30, 2007 and 2006, respectively.

In 2006, we restructured three long-term power purchase contracts with two VIEs, of which we are not the primary beneficiary. The restructured contracts expire between 2015 and 2017. We have remaining purchase commitments with these two VIE supplier entities of $1 billion at September 30, 2007. We are not subject to any risk of loss from these VIEs, other than the remaining purchase commitments. We paid $27 million and $29 million for electric generation capacity and $16 million and $14 million for electric energy from these entities in the three months ended September 30, 2007 and 2006, respectively. We paid $86 million and $87 million for electric generation capacity and $44 million and $42 million for electric energy from these entities in the nine months ended September 30, 2007 and 2006, respectively.

During 2005, we entered into four long-term contracts with unrelated limited liability companies (LLCs) to purchase synthetic fuel produced from coal. Certain variable pricing terms in the contracts protect the equity holders from variability in the cost of their coal purchases, and therefore, the LLCs were determined to be VIEs. After completing our FIN 46R analysis, we concluded that although our interests in the contracts, as a result of their pricing terms, represent variable interests in the LLCs, we are not the primary beneficiary. We paid $120 million and $36 million to the LLCs for coal and synthetic fuel produced from coal in the three months ended September 30, 2007 and 2006, respectively, and $333 million and $243 million to the LLCs for coal and synthetic fuel produced from coal in the nine months ended September 30, 2007 and 2006, respectively. We are not subject to any risk of loss from the contractual arrangements, as our only obligation to the VIEs is to purchase the synthetic fuel that the VIEs produce according to the terms of the applicable purchase contracts. These contracts will terminate on December 31, 2007.

Our Consolidated Balance Sheet as of December 31, 2006, reflected net property, plant and equipment of $337 million and $370 million of debt, related to the consolidation, in accordance with FIN 46R, of a variable interest lessor entity through which we had financed and leased a power generation plant for our utility operations. The debt was non-recourse to us and was secured by the entity's property, plant and equipment. The lease under which we operated the power generation facility terminated in August 2007 and we took legal title to the facility through the repayment of the lessor's related debt.

As discussed in Note 27 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, DCI held an investment in the subordinated notes of a third-party CDO entity. The CDO entity's primary focus is the purchase and origination of middle market senior secured first and second lien commercial and industrial loans in both the primary and secondary loan markets. We concluded that the CDO entity is a VIE and that DCI is the primary beneficiary of the CDO entity, which we have consolidated in accordance with FIN 46R. At September 30, 2007, the CDO entity had $420 million of notes payable that mature in January 2017 and are nonrecourse to us. The CDO entity held the following assets that serve as collateral for its obligations at September 30, 2007:

(millions)	Amount
Other current assets	$ 199
Loans held for sale	394
Other investments	33
Total assets	$ 626

Dominion reports loans held for sale at the lower of cost or market (LOCOM). We determine any LOCOM adjustment to the loans held for sale on a pool basis by aggregating those loans based on similar risks and characteristics. The fair value of the loans are calculated by discounting scheduled cash flows through the estimated maturity using estimated market discount rates that reflect the credit and interest rate risk inherent in the loan, current economic conditions, and lending conditions. The estimates of maturity are based on historical experience with repayments for each loan classification. During the third quarter of 2007, the fair value of the loans was determined to be less than the cost of the loans and we recognized an impairment loss on the loans of $54 million ($35 million after-tax).

Note 17. Significant Financing Transactions

Credit Facilities and Short-Term Debt

As a result of the merger of CNG with Dominion, all of CNG's former credit facilities have been assumed by Dominion. We use short-term debt, primarily commercial paper, to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, we utilize cash and letters of credit to fund collateral requirements under our commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels and the credit quality of our companies and their counterparties. At September 30, 2007, we had committed lines of credit totaling $4.9 billion. These lines of credit support commercial paper borrowings and letter of credit issuances. At September 30, 2007, we had the following commercial paper and letters of credit outstanding and capacity available under credit facilities:

(millions)	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
Five-year joint revolving credit facility[1]	$3,000	$ —	$ 155	$ 2,845
Five-year Dominion credit facility[2]	1,700	—	247	1,453
Five-year Dominion bilateral facility[3]	200	—	—	200
Totals	$4,900	$ —	$ 402	$ 4,498

(1) The $3.0 billion five-year credit facility was entered into in February 2006 and terminates in February 2011. This credit facility can also be used to support up to $1.5 billion of letters of credit.

(2) The $1.7 billion five-year credit facility is used to support the issuance of letters of credit and commercial paper. The facility was entered into in February 2006 and terminates in August 2010.

(3) The $200 million five-year facility was entered into in December 2005 and terminates in December 2010. This credit facility can be used to support commercial paper and letter of credit issuances.

In addition to the facilities above, we also entered into a $100 million bilateral credit facility in August 2004 that terminates in August 2009. At September 30, 2007, there were no letters of credit outstanding under this facility.

Long-Term Debt

In May 2007, Virginia Power issued $600 million of 6.0% senior notes that mature in 2037. In September 2007, Virginia Power issued $600 million of 5.95% senior notes that mature in 2017. The proceeds were used for general corporate purposes, including the repayment of short-term debt.

We repaid $5.4 billion of long-term debt and notes payable during the nine months ended September 30, 2007, which includes the completion of a debt tender offer repurchasing $2.5 billion of our debt securities in July 2007. We recognized charges of $242 million ($148 million after-tax) primarily in connection with the early redemption of this debt. Of this amount, $234 million ($143 million after-tax) was recorded in interest and related charges in our Consolidated Statement of Income.

Included in the debt repayments above is the redemption of all 8 million units of the $200 million 7.8% Dominion CNG Capital Trust I debentures due October 31, 2041. These securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions. Also included is the redemption of approximately 240 thousand units of the $250 million 8.4% Dominion Capital Trust III debentures due January 15, 2031. These securities were redeemed at a price of $1,000 per preferred security plus accrued and unpaid distributions.

Convertible Securities

In December 2003, we issued $220 million of contingent convertible senior notes that are convertible by holders into a combination of cash and shares of our common stock under certain circumstances. At September 30, 2007, since none of these conditions had been met, these senior notes are not yet subject to conversion. In 2004 and 2005, we entered into exchange transactions with respect to these contingent convertible senior notes in contemplation of EITF Issue No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share*. We exchanged the outstanding notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. At issuance, the notes were valued at a conversion rate of 13.5865 shares of common stock per $1,000 principal amount of senior notes, which represented a conversion price of $73.60. Amounts payable in excess of the principal amount will be paid in common stock. The conversion rate is subject to adjustment upon certain events such as subdivisions, splits, combinations of common stock or the issuance to all common stock holders of certain common stock rights, warrants or options and certain dividend increases. As of September 30, 2007, the conversion rate has been adjusted to 13.7425 primarily due to individual dividend payments above the level paid at issuance.

The new notes have been included in the diluted EPS calculation using the method described in EITF 04-8 when appropriate. Under this method, the number of shares included in the denominator of the diluted EPS calculation is calculated as the net shares issuable for the reporting period based upon the average market price for the period. This results in an increase in the average shares outstanding used in the calculation of our diluted EPS when the conversion price of $73.60 is lower than the average market price of our common stock over the period, and no adjustment when the conversion price exceeds the average market price.

Issuance of Common Stock

During the nine months ended September 30, 2007, we issued 3.2 million shares and received cash proceeds of $193 million, in connection with the exercise of employee stock options.

Repurchases of Common Stock

During the nine months ended September 30, 2007, we repurchased 64.5 million shares of common stock for approximately $5.8 billion. This amount includes the completion of our equity tender offer in August 2007, in which we purchased approximately 57.8 million shares at a price of $91 per share for a total cost of approximately $5.3 billion, excluding fees and expenses related to the tender.

At September 30, 2007, our remaining repurchase authorization is the lesser of 27.0 million shares or $2.7 billion of our outstanding common stock.

Note 18. Stock-Based Awards

In April 2005, our shareholders approved the 2005 Incentive Compensation Plan (2005 Incentive Plan) for employees and the Non-Employee Directors Compensation Plan (Non-Employee Directors Plan). The 2005 Incentive Plan permits stock-based awards that include restricted stock, performance grants, goal-based stock and stock options and the Non-Employee Directors Plan permits restricted stock and stock options. Under provisions of both plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms are set at the discretion of the Compensation, Governance and Nominating (CGN) Committee of the Board of Directors or the Board of Directors itself, as provided under each individual plan. Prior to April 2005, we had an incentive compensation plan that provided stock options and restricted stock awards to directors, executives and other key employees with vesting periods from one to five years. Stock options generally had contractual terms from six and one half to ten years in length.

Our results for the three months ended September 30, 2007 and 2006 include $14 million and $8 million, respectively, of compensation costs and $5 million and $3 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Our results for the nine months ended September 30, 2007 and 2006 include $38 million and $23 million, respectively, of compensation costs and $14 million and $9 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in our Consolidated Statements of Income.

Stock Options

The following table provides a summary of changes in amounts of stock options outstanding as of and for the nine months ended September 30, 2007:

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life	Aggregated intrinsic value(1)
	(thousands)		(years)	(millions)
Outstanding and exercisable at January 1, 2007	7,246	$ 60.51		
Exercised	(3,167)	60.03		$ 90
Outstanding and exercisable at September 30, 2007	4,079	$ 60.88	2.96	$ 96

(1) Intrinsic value represents the difference between the exercise price of the option and the market value of our stock.

We issue new shares to satisfy stock option exercises. We received cash proceeds from the exercise of stock options of approximately $193 million and $23 million in the nine months ended September 30, 2007 and 2006, respectively.

SFAS No. 123R, *Share-Based Payment*, requires the benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation (excess tax benefits) to be classified as a financing cash flow. Approximately $35 million and $2 million of excess tax benefits were realized for the nine months ended September 30, 2007 and 2006, respectively.

Restricted Stock

The fair value of our restricted stock awards is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of restricted stock activity for the nine months ended September 30, 2007:

	Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2007	1,246	$ 65.43
Granted	243	89.03
Vested	(342)	65.62
Cancelled and forfeited	(35)	75.65
Nonvested at September 30, 2007	1,112	$ 70.21

As of September 30, 2007, unrecognized compensation cost related to nonvested restricted stock awards totaled approximately $31 million and is expected to be recognized over a weighted-average period of 1.5 years. Restricted stock awards granted prior to January 1, 2006 contain terms that accelerate vesting upon retirement. We continue to recognize compensation cost over the stated vesting term for existing restricted stock awards, but are now required to recognize compensation cost over the shorter of the stated vesting term or period from the date of grant to the date of retirement eligibility for newly issued or modified restricted stock awards with similar terms. We recognized compensation cost related to awards previously granted to retirement-eligible employees of approximately $1 million for the three months ended September 30, 2007 and 2006, and approximately $3 million and $4 million in the nine months ended September 30, 2007 and 2006, respectively. At September 30, 2007, unrecognized compensation cost for restricted stock awards held by retirement-eligible employees totaled approximately $2 million.

Goal-Based Stock

Goal-based stock awards are generally granted to key non-officer employees on an annual basis. The issuance of awards is based on the achievement of multiple performance metrics during a two-year period, including return on invested capital and total shareholder return relative to that of a peer group of companies. Goal-based stock awards were also granted in lieu of cash-based performance grants to certain officers who had not achieved a certain level of share ownership. At September 30, 2007, the targeted number of shares to be issued is approximately 148 thousand, but the actual number of shares issued will vary between zero and 200% of targeted shares depending on the level of performance metrics achieved. The fair value of goal-based stock is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of goal-based stock activity:

	Targeted Number of Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2007	97	$ 69.53
Granted	77	88.53
Vested	(11)	69.53
Cancelled and forfeited	(15)	69.97
Nonvested at September 30, 2007	148	$ 79.48

At September 30, 2007, unrecognized compensation cost related to nonvested goal-based stock awards totaled approximately $8 million and is expected to be recognized over a weighted-average period of 1.6 years.

Cash-Based Performance Grant

In April 2006, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2008 and is based on the achievement of two performance metrics during 2006 and 2007: return on invested capital and total shareholder return relative to that of a peer group of companies. At September 30, 2007, the targeted amount of the grant is $13 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved.

In April 2007, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2009 and is based on the achievement of two performance metrics during 2007 and 2008: return on invested capital and total shareholder return relative to that of a peer group of companies. At September 30, 2007, the targeted amount of the grant is $12 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved.

At September 30, 2007, a liability of $15 million has been accrued for these awards.

Note 19. Commitments and Contingencies

Other than the following matters, there have been no significant developments regarding the commitments and contingencies disclosed in Note 23 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, Note 15 to the Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, or Note 18 to the Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2007, nor have any significant new matters arisen during the three months ended September 30, 2007.

Long-Term Purchase Agreements

In connection with the sale of our offshore E&P operations, Eni has indemnified us and assumed the post-closing unconditional purchase obligations associated with these operations. As a result, the following long-term commitments at December 31, 2006 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, are now the responsibility of Eni:

(millions)	2007	2008	2009	2010	2011	Thereafter	Total
Production handling for gas and oil production operations	$ 54	$ 43	$ 26	$ 15	$ 11	$ 5	$ 154

Lease Commitments

In connection with the sale of our non-Appalachian E&P business, the purchasers indemnified us and assumed the post-closing obligations associated with non-Appalachian lease commitments. Following the completion of the sale of our non-Appalachian E&P business, our lease commitments, as shown in our Annual Report on Form 10-K for the year ended December 31, 2006, were reduced as follows:

(millions)	2007	2008	2009	2010	2011	Thereafter	Total
Total lease commitments	$209	$182	$163	$131	$119	$ 294	$1,098
Less: non-Appalachian E&P business	(81)	(62)	(55)	(33)	(26)	(40)	(297)
Total lease commitments as adjusted at December 31, 2006	$128	$120	$108	$ 98	$ 93	$ 254	$ 801

Litigation

In 2006, Gary P. Jones and others filed suit against DTI, Dominion Exploration and Production, Inc. (DEPI) and Dominion Resources Services, Inc. (DRS). The plaintiffs are royalty owners, seeking to recover damages as a result of the Dominion defendants allegedly underpaying royalties by improperly deducting post-production costs and not paying fair market value for the gas produced from their leases. The plaintiffs seek class action status on behalf of all West Virginia residents and others who are parties to or beneficiaries of oil and gas leases with the Dominion defendants. DRS is erroneously named as a defendant as the parent company of DTI and DEPI. In the first quarter of 2007, we established a litigation reserve representing our best estimate of the probable loss related to this matter. In the third quarter of 2007, we increased the litigation reserve to reflect our revised estimate of the probable loss related to this matter. We do not believe that the final resolution of this matter will have a material adverse effect on our results of operations or financial condition.

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Guarantees

At September 30, 2007, we had issued $41 million of guarantees to support third parties, equity method investees and employees affected by Hurricane Katrina. We also enter into guarantee arrangements on behalf of our consolidated subsidiaries primarily to facilitate their commercial transactions with third parties. To the extent that a liability subject to a guarantee has been incurred by one of our consolidated subsidiaries, that liability is included in our Consolidated Financial Statements. We are not required to recognize liabilities for guarantees issued on behalf of our subsidiaries unless it becomes probable that we will have to perform under the guarantees. We believe it is unlikely that we would be required to perform or otherwise incur any losses associated with guarantees of our subsidiaries' obligations. At September 30, 2007, we had issued the following subsidiary guarantees:

(millions)	Stated Limit	Value[1]
Subsidiary debt[2]	$ 47	$ 47
Commodity transactions[3]	3,097	495
Lease obligation for power generation facility[4]	935	935
Nuclear obligations[5]	383	302
Other	275	148
Total	$ 4,737	$ 1,927

(1) Represents the estimated portion of the guarantee's stated limit that is utilized as of September 30, 2007, based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by our subsidiaries, the value includes the recorded amount.

(2) Guarantees of debt of a DEI subsidiary. In the event of default by the subsidiary, we would be obligated to repay such amount.

(3) Guarantees related to energy trading and marketing activities and other commodity commitments of certain subsidiaries, including subsidiaries of Virginia Power and DEI. These guarantees were provided to counterparties in order to facilitate physical and financial transactions in gas, oil, electricity, pipeline capacity, transportation and related commodities and services. If these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, we would be obligated to satisfy such obligation. We and our subsidiaries receive similar guarantees as collateral for credit extended to others. The value provided includes certain guarantees that do not have stated limits.

(4) Guarantee of a DEI subsidiary's leasing obligation for the Fairless Energy Power Station.

(5) Guarantees related to certain DEI subsidiaries' potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and guarantees for a DEI subsidiary's and Virginia Power's commitment to buy nuclear fuel. In addition to the guarantees listed above, we have also agreed to provide up to $150 million and $60 million to two DEI subsidiaries, to pay operating expenses of Millstone and Kewaunee power stations, respectively, in the event of a prolonged outage as part of satisfying certain Nuclear Regulatory Commission requirements concerned with ensuring adequate funding for the operations of nuclear power stations.

Surety Bonds and Letters of Credit

As of September 30, 2007, we had also purchased $88 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $402 million. We enter into these arrangements to facilitate commercial transactions by our subsidiaries with third parties.

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 September 30, 2007, 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.

We have entered into other types of contracts that require indemnifications, such as purchase and sale agreements and financing agreements. These agreements may include, but are not limited to, indemnifications around certain title, tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price and is typically limited in duration depending on the nature of the indemnified matter. Since January 1, 2004, we have entered into sale agreements with maximum exposure related to the collective purchase prices of approximately $16 billion, for breach of certain corporate representations (e.g. title to shares, due authorization), with maximum indemnity exposure for other general business representations (e.g. environmental, contracts, employee matters, etc.) being generally limited to approximately 10% or less of the purchase price for a set period of time after closing. We believe that it is unlikely that we would be required to perform under these indemnifications and have not recognized any significant liabilities related to these arrangements.

Note 20. Credit Risk

Credit risk is our risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. 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 September 30, 2007 provision for credit losses, 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.

As a diversified energy company, we transact with major companies in the energy industry and with commercial and residential energy consumers. These transactions principally occur in the Northeast, Mid-Atlantic and Midwest regions of the U.S. We do not believe that this geographic concentration contributes significantly to our overall exposure to credit risk. In addition, as a result of our large and diverse customer base, we are not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations, including transmission services and retail energy sales.

Our exposure to credit risk is concentrated primarily within our energy marketing and price risk management activities, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include trading of energy-related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. 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. Gross credit exposure is calculated prior to the application of collateral. At September 30, 2007, our gross credit exposure totaled $764 million. After the application of collateral, our credit exposure was reduced to $758 million. Of this amount, investment grade counterparties, including those internally rated, represented 88% and no single counterparty exceeded 9%.

Note 21. Employee Benefit Plans

The components of the provision for net periodic benefit cost were as follows:

(millions)	Pension Benefits 2007	Pension Benefits 2006	Other Postretirement Benefits 2007	Other Postretirement Benefits 2006
Three Months Ended September 30,				
Service cost	**$ 36**	$ 30	**$ 13**	$ 15
Interest cost	**70**	50	**20**	17
Expected return on plan assets	**(124)**	(86)	**(17)**	(12)
Amortization of prior service cost (credit)	**—**	1	**(1)**	(1)
Amortization of transition obligation	**—**	—	**—**	1
Amortization of net loss	**12**	22	**2**	5
Settlements and curtailments[1]	**—**	—	**(1)**	—
Net periodic benefit cost (credit)[2]	**$ (6)**	$ 17	**$ 16**	$ 25
Nine Months Ended September 30,				
Service cost	**$ 89**	$ 95	**$ 41**	$ 55
Interest cost	**172**	158	**58**	61
Expected return on plan assets	**(305)**	(271)	**(53)**	(44)
Amortization of prior service cost (credit)	**2**	3	**(4)**	(3)
Amortization of transition obligation	**—**	—	**2**	3
Amortization of net loss	**30**	69	**5**	20
Benefit enhancement[3]	**3**	—	**9**	—
Settlements and curtailments[1]	**7**	6	**(1)**	—
Net periodic benefit cost (credit)[2]	**$ (2)**	$ 60	**$ 57**	$ 92

(1) Relates to the pending sale of Peoples and Hope and sale of our non-Appalachian E&P business.
(2) Reduction in pension and other postretirement benefit costs, primarily reflecting an increase in the associated discount rate.
(3) Represents a one-time benefit enhancement for certain employees in connection with the disposition of our non-Appalachian E&P business.

Employer Contributions

Under our funding policies, we evaluate pension and other postretirement benefit plan funding requirements annually, usually in the second half of the year after receiving updated plan information from our actuary. Based on the funded status of each plan and other factors, the amount of additional contributions to be made each year is determined at that time. We made no contributions to our defined benefit pension plans or other postretirement benefit plans during the nine months ended September 30, 2007. We do not expect to make any contributions to our pension plans during the remainder of the year. We expect to contribute approximately $23 million to our other postretirement benefit plans during the fourth quarter of 2007.

Note 22. Operating Segments

Our Company is organized primarily on the basis of products and services sold in the U.S. We manage our operations through the following segments.

Dominion Delivery includes our regulated electric and gas distribution and customer service businesses, as well as nonregulated retail energy marketing operations.

Dominion Energy includes our regulated electric transmission, natural gas transmission pipeline and underground natural gas storage businesses and the Cove Point LNG facility. It also includes gathering and extraction activities, certain Appalachian natural gas production and producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage and associated gas trading.

Dominion Generation includes the generation operations of our merchant fleet and regulated electric utility, as well as energy marketing and price risk management activities associated with our generation assets.

Dominion E&P includes our gas and oil exploration, development and production operations. These operations were located in several major producing basins in the lower 48 states, including the outer continental shelf and deepwater areas of the Gulf of Mexico, West Texas, Mid-Continent, the Rockies and Appalachia. We have sold all of our non-Appalachian natural gas and oil E&P operations.

Corporate includes our corporate, service company and other functions (including unallocated debt), corporate-wide enterprise commodity risk management, the remaining assets of DCI and the net impact of the discontinued operations of the Peaker facilities and the Canadian E&P business. In addition, the contribution to net income by our primary operating segments is determined based on a measure of profit that executive 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 in assessing the segment's performance or allocating resources among the segments and are instead reported in the Corporate segment. In the nine months ended September 30, 2007 and 2006, we reported a net benefit of $939 million and net expenses of $111 million, respectively, in the Corporate segment attributable to our operating segments.

The net benefit in 2007 largely resulted from:

- A $3.6 billion ($2.1 billion after-tax) net gain resulting from the completion of the sale of our U.S. non-Appalachian E&P business, attributable to Dominion E&P; partially offset by
- A $544 million ($347 million after-tax) charge predominantly due to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges, attributable to Dominion E&P. As a result of the sale of our U.S. non-Appalachian E&P business, it became probable that the forecasted sales of gas and oil would not occur;
- A $387 million ($252 million after-tax) charge related to the impairment of Dresden, attributable to Dominion Generation;
- A $259 million ($158 million after-tax) extraordinary charge due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, attributable to Dominion Generation;
- A $236 million ($140 million after-tax) charge for the recognition of a long-term power sales agreement at State Line, that no longer qualifies for the normal purchase and sales exemption due to the expected termination of the agreement in the fourth quarter 2007, attributable to Dominion Generation; and
- A $171 million ($108 million after-tax) charge for the recognition of certain forward gas contracts that no longer qualify for the normal purchase and sales exemption as a result of the sale of our U.S. non-Appalachian E&P business, attributable to Dominion E&P.

The net expenses in 2006 primarily related to the impact of a $167 million ($103 million after-tax) charge resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, attributable to Dominion Delivery.

Intersegment sales and transfers are based on contractual arrangements and may result in intersegment profit or loss that is eliminated in consolidation.

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The following table presents segment information pertaining to our operations:

(millions)	Dominion Delivery	Dominion Energy	Dominion Generation	Dominion E&P	Corporate	Adjustments/ Eliminations	Consolidated Total
Three Months Ended September 30,							
2007							
Total revenue from external customers	$ 673	$ 134	$ 2,229	$ 178	$ 23	$ 352	$ 3,589
Intersegment revenue	3	453	31	51	160	(698)	—
Total operating revenue	676	587	2,260	229	183	(346)	3,589
Loss from discontinued operations, net of tax	—	—	—	—	(3)	—	(3)
Net income	74	61	403	38	1,741	—	2,317
2006							
Total revenue from external customers	$ 650	$ 198	$ 1,996	$ 829	$ (25)	$ 325	$ 3,973
Intersegment revenue	2	382	29	50	186	(649)	—
Total operating revenue	652	580	2,025	879	161	(324)	3,973
Loss from discontinued operations, net of tax	—	—	—	—	(1)	—	(1)
Net income (loss)	78	102	253	297	(76)	—	654
Nine Months Ended September 30,							
2007							
Total revenue from external customers	$ 3,100	$ 737	$ 5,745	$ 1,411	$ 54	$ 933	$ 11,980
Intersegment revenue	19	1,156	98	164	475	(1,912)	—
Total operating revenue	3,119	1,893	5,843	1,575	529	(979)	11,980
Extraordinary item	—	—	—	—	(158)	—	(158)
Loss from discontinued operations, net of tax	—	—	—	—	(5)	—	(5)
Net income	356	232	623	314	715	—	2,240
2006							
Total revenue from external customers	$ 3,059	$ 1,043	$ 5,218	$ 2,406	$ (102)	$ 751	$ 12,375
Intersegment revenue	8	945	110	168	567	(1,798)	—
Total operating revenue	3,067	1,988	5,328	2,574	465	(1,047)	12,375
Income from discontinued operations, net of tax	—	—	—	—	14	—	14
Net income (loss)	314	277	456	615	(313)	—	1,349

In the fourth quarter of 2007, we will realign our business units to reflect our strategic refocusing and begin managing our daily operations through three primary operating segments: DVP, Dominion Generation and Dominion Energy. DVP will include our regulated electric distribution and electric transmission operations in Virginia and North Carolina, as well as our nonregulated retail energy marketing and customer service operations. Dominion Generation will continue to include our regulated and merchant power generation. Dominion Energy will include our regulated natural gas distribution, transmission, storage and LNG operations, Appalachian-based natural gas and oil E&P operations and producer services.

DOMINION RESOURCES, INC.
ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) discusses the results of operations and general financial condition of Dominion. MD&A should be read in conjunction with our Consolidated Financial Statements. The terms "Dominion," "Company," "we," "our" and "us" are used throughout MD&A and, depending on the context of their use, may represent any of the following: the legal entity, Dominion Resources, Inc., one of Dominion Resources, Inc.'s consolidated subsidiaries or operating segments, or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries.

Contents of MD&A

Our MD&A consists of the following information:

- Forward-Looking Statements
- Accounting Matters
- Results of Operations
- Segment Results of Operations
- Selected Information — Energy Trading Activities
- Liquidity and Capital Resources
- Future Issues and Other Matters

Forward-Looking Statements

This report contains statements concerning our 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" 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 winter 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, 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;
- Counterparty credit risk;
- Capital market conditions, including price risk due to marketable securities held as investments in nuclear decommissioning and benefit plan trusts;
- Fluctuations in interest rates;
- 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;
- Receipt of approvals for and timing of closing dates for acquisitions and divestitures, including our divestiture of Peoples and Hope;
- Risks associated with the realignment of our operating assets, including the potential dilutive effect on earnings in the near term;
- Political and economic conditions, including the threat of domestic terrorism, inflation and deflation;
- Completing the divestiture of investments held by our financial services subsidiary, DCI; and

- Changes in rules for RTOs in which we participate, including changes in rate designs and new and evolving capacity models.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors in this report, in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007 and in our Annual Report on Form 10-K for the year ended December 31, 2006.

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

As of September 30, 2007, there have been no significant changes with regard to the critical accounting policies and estimates disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006. The policies disclosed included the accounting for derivative contracts at fair value, goodwill and long-lived asset impairment testing, asset retirement obligations, employee benefit plans, regulated operations, gas and oil operations, and income taxes.

Other

See Notes 3 and 4 to our Consolidated Financial Statements for a discussion of newly adopted and recently issued accounting standards. See Note 5 to our Consolidated Financial Statements for a discussion of the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations.

Results of Operations

Presented below is a summary of our consolidated results for the quarter and year-to-date periods ended September 30, 2007 and 2006:

(millions, except EPS)	2007	2006	$ Change
Third Quarter			
Net income	**$2,317**	$ 654	$ 1,663
Diluted EPS	**7.24**	1.85	5.39
Year-To-Date			
Net income	**$2,240**	$1,349	$ 891
Diluted EPS	**6.58**	3.84	2.74

Overview

Third Quarter 2007 vs. 2006

Net income increased by 254% to $2.3 billion. Diluted EPS increased to $7.24 and includes $0.15 of share accretion resulting from the repurchase of shares with proceeds received from the sale of our non-Appalachian E&P business. Favorable drivers include the gain on the sale of our U.S. non-Appalachian E&P business, higher realized prices for our gas and oil production and the reapplication of deferral accounting effective July 1, 2007, for Virginia jurisdiction fuel costs at our utility generation operations. Unfavorable drivers include a decrease in gas and oil production due to the sale of our U.S. non-Appalachian E&P business, charges related to the early extinguishment of outstanding debt associated with the completion of our debt tender offer in July 2007, a charge for the expected termination of a long-term power sales agreement at State Line and the absence of business interruption insurance revenue received in 2006, associated with the 2005 hurricanes.

Year-To-Date 2007 vs. 2006

Net income increased by 66% to $2.2 billion. Diluted EPS increased to $6.58 and includes $0.11 of share accretion resulting from the repurchase of shares with proceeds received from the sale of our non-Appalachian E&P business. Favorable drivers include the gain on the sale of our U.S. non-Appalachian E&P business, higher realized prices for our gas and oil production, higher margins at our merchant generation business and the reapplication of deferral accounting effective July 1, 2007, for Virginia jurisdiction fuel costs at our utility generation operations. Unfavorable drivers include a decrease in gas and oil production due to the sale of our U.S. non-Appalachian E&P business, an impairment charge related to the sale of Dresden, an extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, charges related to the early extinguishment of outstanding debt associated with the completion of our debt tender offer in July 2007, a charge due to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges as a result of the sale of our U.S. non-Appalachian E&P business, a charge for the expected termination of a long-term power sales agreement at State Line and the absence of business interruption insurance revenue received in 2006, associated with the 2005 hurricanes.

Analysis of Consolidated Operations

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

	Third Quarter			Year-To-Date		
(millions)	2007	2006	$ Change	2007	2006	$ Change
Operating Revenue	**$ 3,589**	$3,973	$ (384)	**$11,980**	$12,375	$ (395)
Operating Expenses						
Electric fuel and energy purchases	**914**	1,057	(143)	**2,742**	2,580	162
Purchased electric capacity	**111**	122	(11)	**339**	361	(22)
Purchased gas	**346**	343	3	**2,024**	2,153	(129)
Other energy-related commodity purchases	**64**	144	(80)	**184**	862	(678)
Other operations and maintenance	**1,159**	502	657	**3,906**	2,123	1,783
Gain on sale of U.S. non-Appalachian E&P business	**(3,617)**	—	(3,617)	**(3,602)**	—	(3,602)
Depreciation, depletion and amortization	**284**	389	(105)	**1,116**	1,146	(30)
Other taxes	**113**	122	(9)	**436**	430	6
Other income	**33**	43	(10)	**125**	134	(9)
Interest and related charges	**437**	256	181	**974**	764	210
Income tax expense	**1,498**	421	1,077	**1,576**	750	826
Extraordinary item, net of tax	**—**	—	—	**(158)**	—	(158)

An analysis of our results of operations for the third quarter and year-to-date periods of 2007 compared to the third quarter and year-to-date periods of 2006 follows:

Third Quarter 2007 vs. 2006

Operating Revenue decreased 10% to $3.6 billion, primarily reflecting:

- A $299 million decrease in sales of gas and oil production primarily due to lower volumes ($589 million), partially offset by higher realized prices ($290 million);
- A $269 million decrease related to business interruption insurance revenue received in 2006, associated with the 2005 hurricanes;
- An $82 million decrease in nonutility coal sales, primarily from lower sale volumes related to exiting certain sales activities. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*; and
- A $35 million decrease in sales of extracted products due to the sale of our U.S. non-Appalachian E&P business.

These decreases were partially offset by:

- A $147 million increase in revenue from our electric utility operations, largely resulting from:
  - A $70 million increase due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;
  - A $46 million increase in sales to retail customers attributable to variations in rates resulting from changes in sales mix and other factors ($25 million) and new customer connections ($21 million) primarily in our residential and commercial customer classes; and
  - A $22 million increase in sales to wholesale customers.
- An $87 million increase for merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations, increased volumes for fossil operations and higher capacity revenue associated with new capacity markets in New England Power Pool (NEPOOL) and PJM; and
- A $74 million increase associated with hedging activities for our merchant generation assets. The effect of this increase was largely offset by a corresponding increase in *Other operations and maintenance expense*.

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Operating Expenses and Other Items

Electric fuel and energy purchases expense decreased 14% to $914 million, primarily reflecting the combined impact of the following:

- A $212 million decrease for utility generation operations primarily due to the reapplication of deferral accounting for Virginia jurisdiction fuel costs beginning on July 1, 2007. The underlying fuel costs, including those subject to deferral accounting, increased by approximately $26 million due to higher consumption of fossil fuel and purchased power resulting primarily from a change in generation mix. This increase was more than offset by a $238 million reduction in fuel expenses, primarily to defer fuel costs that were in excess of current period fuel rate recovery; partially offset by

- A $38 million increase related to our retail energy marketing operations resulting from an increase in volume ($19 million) and higher prices ($19 million).

Other energy-related commodity purchases expense decreased 56% to $64 million, primarily due to an $80 million decrease in the cost of nonutility coal sales, discussed in *Operating Revenue.*

Other operations and maintenance expense increased to $1.2 billion, primarily reflecting the combined effects of:

- A $236 million charge related to the expected termination of a long-term power sales agreement at State Line;

- $86 million of impairment charges related to DCI investments;

- A $71 million increase primarily related to hedging activities associated with our merchant generation assets. The effect of this increase is more than offset by a corresponding increase in *Operating Revenue;*

- A $62 million increase primarily due to the inclusion of financial transmission rights revenue, which is used to offset congestion costs associated with PJM power purchases incurred by our utility generation operations, in *Electric fuel and energy purchases expense*, beginning July 1, 2007, as a result of the reapplication of deferred fuel accounting for the Virginia jurisdiction;

- A $46 million increase primarily due to the absence of a 2006 benefit from favorable changes in the fair value of certain gas and oil hedges that were dedesignated following the 2005 hurricanes;

- A $45 million decrease in gains from the sales of emissions allowances held for consumption; and

- A $27 million charge resulting from the accrual of litigation reserves.

Gain on sale of U.S. non-Appalachian E&P business reflects the pre-tax gain of $3.6 billion resulting from the completion of the sale of our U.S. non-Appalachian E&P business.

Depreciation, depletion and amortization decreased 27% to $284 million, principally due to decreased oil and gas production resulting from the sale of our U.S. non-Appalachian E&P business.

Other income decreased 23% to $33 million, resulting primarily from lower decommissioning trust earnings due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, since they are deferred as a regulatory liability.

Interest and related charges increased 71% to $437 million, resulting principally from charges related to the early extinguishment of outstanding debt associated with our debt tender offer completed in July 2007, partially offset by a reduction in interest expense resulting from the retirement of this debt.

Income tax expense increased to $1.5 billion, reflecting income tax expense on the gain realized from the sale of our U.S. non-Appalachian E&P business.

Year-To-Date 2007 vs. 2006

Operating Revenue decreased 3% to $12 billion, primarily reflecting:

- A $422 million decrease in revenue from sales of oil purchased by E&P operations, primarily due to the impact of netting sales and purchases of oil under buy/sell arrangements associated with the implementation of EITF 04-13 in 2006. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense;*

- A $269 million decrease related to business interruption insurance revenue received in 2006, associated with the 2005 hurricanes;

- A $242 million decrease in gas sales by our gas distribution operations reflecting the combined effects of:

  - A $200 million decrease reflecting lower gas prices; and

   - A $198 million decrease resulting from the migration of customers to energy choice programs; partially offset by
   - A $156 million increase in volumes due to an increase in the number of heating degree days, primarily in the first quarter of 2007, and changes in customer usage patterns and other factors. This decrease was more than offset by a corresponding decrease in *Purchased gas expense.*

- A $227 million decrease in nonutility coal sales, primarily from lower sale volumes ($210 million) related to exiting certain sales activities and lower prices ($17 million). This decrease was more than offset by a corresponding decrease in *Other energy-related commodity purchases expense*;
- A $210 million decrease in sales of gas and oil production primarily due to lower volumes ($770 million), partially offset by higher realized prices ($560 million);
- A $58 million decrease in our producer services business as the result of lower margins related to price risk management activities;
- A $52 million decrease in revenue from sales of gas purchased by E&P operations to facilitate gas transportation and other contracts primarily due to the implementation of EITF 04-13 and a reduction in quantities of purchased gas. This decrease was more than offset by a corresponding decrease in *Purchased gas expense*; and
- A $40 million decrease in the sales of emissions allowances held for resale. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense.*

These decreases were partially offset by:

- A $362 million increase in revenue from our electric utility operations, largely resulting from:
   - A $125 million increase in sales to retail customers attributable to variations in rates resulting from changes in sales mix and other factors ($71 million) and new customer connections ($54 million) primarily in our residential and commercial customer classes;
   - A $90 million increase in sales to retail customers due to an increase in the number of heating and cooling degree days;
   - A $56 million increase due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;
   - A $50 million increase in sales to wholesale customers; and
   - A $32 million increase resulting primarily from higher ancillary service revenue reflecting higher regulation and operating reserves revenue received from PJM.
- A $288 million increase for merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations, increased volumes for fossil operations and higher capacity revenue associated with new capacity markets in NEPOOL and PJM;
- A $233 million increase associated with hedging activities for our merchant generation assets. The effect of this increase was largely offset by a corresponding increase in *Other operations and maintenance expense*;
- A $135 million increase in gas sales by retail energy marketing activities due to increased customer accounts ($178 million) partially offset by lower contracted sales prices ($43 million). This increase was largely offset by a corresponding increase in *Purchased gas expense*; and
- A $66 million increase in gas transportation and storage revenue primarily attributable to our gas distribution operations due to increased volumes and higher prices.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 6% to $2.7 billion, primarily reflecting:

- An $80 million increase related to our retail energy marketing operations resulting from higher prices;
- A $59 million increase for our merchant generation operations primarily due to higher commodity prices and increased fossil fuel consumption; and
- A $12 million increase for utility generation operations. The underlying fuel costs, including those subject to deferral accounting, increased by approximately $237 million 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 $225 million reduction in fuel expenses, primarily to defer fuel costs that were in excess of current period fuel rate recovery.

Purchased gas expense decreased 6% to $2.0 billion, principally resulting from:

- A $192 million decrease in costs attributable to gas distribution operations, primarily reflecting lower prices as discussed in *Operating Revenue*; and

- A $59 million decrease related to E&P operations, resulting from the impact of netting purchases and sales of gas under buy/sale arrangements due to the implementation of EITF 04-13 and a reduction in purchased gas quantities. The effect of this decrease is largely offset by a corresponding decrease in *Operating Revenue.*

These decreases were partially offset by:

- A $111 million increase associated with retail energy marketing activities, due to higher volumes ($162 million), partially offset by lower prices ($51 million), as discussed in *Operating Revenue*; and
- A $19 million increase associated with our producer services business, due to the net impact of an increase in volumes partially offset by lower prices.

Other energy-related commodity purchases expense decreased 79% to $184 million, primarily attributable to the following factors, all of which are discussed in *Operating Revenue*:

- A $409 million decrease as a result of the implementation of EITF 04-13;
- A $229 million decrease in the cost of nonutility coal sales; and
- A $38 million decrease in the cost of sales of emissions allowances held for resale.

Other operations and maintenance expense increased 84% to $3.9 billion, resulting from:

- A $544 million charge predominantly due to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges as a result of the sale of our U.S. non-Appalachian E&P business;
- A $387 million impairment charge related to the sale of Dresden;
- A $236 million charge related to the expected termination of a long-term power sales agreement at State Line;
- A $211 million increase primarily related to hedging activities associated with our merchant generation assets. The effect of this increase is more than offset by a corresponding increase in *Operating Revenue;*
- A $177 million increase primarily due to the absence of a 2006 benefit from favorable changes in the fair value of certain gas and oil hedges that were dedesignated following the 2005 hurricanes;
- A $171 million charge primarily due to the termination of VPP agreements as a result of the sale of our U.S. non-Appalachian E&P business;
- $86 million of impairment charges related to DCI investments;
- A $63 million increase due to a decrease in gains from the sale of emissions allowances held for consumption;
- A $53 million charge resulting from the accrual of litigation reserves; and
- A $40 million increase primarily due to the inclusion of financial transmission rights revenue, which is used to offset congestion costs associated with PJM power purchases incurred by our utility generation operations, in *Electric fuel and energy purchases expense*, beginning July 1, 2007, as a result of the reapplication of deferred fuel accounting for the Virginia jurisdiction.

These charges were partially offset by the absence of the following 2006 items:

- A $167 million charge related to the write-off of certain regulatory assets in connection with the pending sale of Peoples and Hope; and
- A $60 million charge due to the elimination of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts.

Gain on sale of U.S. non-Appalachian E&P business reflects the pre-tax gain of $3.6 billion resulting from the completion of the sale of our U.S. non-Appalachian E&P business.

Interest and related charges increased 27% to $974 million, resulting principally from charges related to the early extinguishment of outstanding debt associated with our debt tender offer completed in July 2007, partially offset by a reduction in interest expense resulting from the retirement of this debt.

Income tax expense increased to $1.6 billion, reflecting income tax expense on the gain realized from the sale of our U.S. non-Appalachian E&P business.

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

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Segment Results of Operations

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit and loss. Presented below is a summary of contributions by operating segments to net income for the quarter and year-to-date periods ended September 30, 2007 and 2006:

	Net Income			Diluted EPS		
Third Quarter	**2007**	**2006**	**$ Change**	**2007**	**2006**	**$ Change**
(millions, except EPS)						
Dominion Delivery	**$ 74**	$ 78	$ (4)	**$0.23**	$ 0.22	$ 0.01
Dominion Energy	**61**	102	(41)	**0.19**	0.29	(0.10)
Dominion Generation	**403**	253	150	**1.26**	0.71	0.55
Dominion E&P	**38**	297	(259)	**0.12**	0.84	(0.72)
Primary operating segments	**576**	730	(154)	**1.80**	2.06	(0.26)
Corporate	**1,741**	(76)	1,817	**5.44**	(0.21)	5.65
Consolidated	**$2,317**	$ 654	$ 1,663	**$7.24**	$ 1.85	$ 5.39
Year-To-Date						
(millions, except EPS)						
Dominion Delivery	**$ 356**	$ 314	$ 42	**$1.05**	$ 0.89	$ 0.16
Dominion Energy	**232**	277	(45)	**0.68**	0.79	(0.11)
Dominion Generation	**623**	456	167	**1.83**	1.31	0.52
Dominion E&P	**314**	615	(301)	**0.92**	1.75	(0.83)
Primary operating segments	**1,525**	1,662	(137)	**4.48**	4.74	(0.26)
Corporate	**715**	(313)	1,028	**2.10**	(0.90)	3.00
Consolidated	**$2,240**	$1,349	$ 891	**$6.58**	$ 3.84	$ 2.74

Dominion Delivery

Presented below are operating statistics related to our Dominion Delivery operations:

	Third Quarter			Year-To-Date		
	2007	**2006**	**% Change**	**2007**	**2006**	**% Change**
Electricity delivered (million mwhrs)(1)	**23.7**	23.1	3%	**64.7**	61.2	6%
Degree days (electric service area):						
Cooling(2)	**1,150**	1,119	3	**1,643**	1,528	8
Heating(3)	**5**	15	(67)	**2,365**	2,056	15
Average electric delivery customer accounts(4)	**2,364**	2,330	1	**2,357**	2,322	2
Gas throughput (bcf):						
Gas sales	**6**	6	—	**65**	68	(4)
Gas transportation	**33**	37	(11)	**186**	167	11
Heating degree days (gas service area)(3)	**69**	111	(38)	**3,830**	3,347	14
Average gas delivery customer accounts(4):						
Gas sales	**776**	780	(1)	**782**	881	(11)
Gas transportation	**890**	893	—	**901**	807	12
Average retail energy marketing customer accounts(4)	**1,566**	1,398	12	**1,529**	1,308	17

mwhrs = megawatt hours

bcf = billion cubic feet

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

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

(3) Heating degree days (HDDs) are units measuring the extent to which the average daily temperature is less than 65 degrees. HDDs are calculated as the difference between the average temperature for each day and 65 degrees.

(4) Period average, in thousands.

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

	Third Quarter 2007 vs. 2006 Increase (Decrease)		Year-To-Date 2007 vs. 2006 Increase (Decrease)	
	Amount	EPS	Amount	EPS
(millions, except EPS)				
Major storm damage and service restoration[1]	$ 7	$ 0.02	$ 6	$ 0.02
Regulated electric sales:				
Customer growth	3	0.01	7	0.02
Weather	(1)	—	13	0.04
Bad debt expense[2]	(4)	(0.01)	(10)	(0.03)
Regulated gas sales – weather	(1)	—	14	0.04
Retail energy marketing operations[3]	—	—	8	0.03
Other	(8)	(0.03)	4	0.01
Share accretion	—	0.02	—	0.03
Change in net income contribution	$ (4)	$ 0.01	$ 42	$ 0.16

(1) Primarily resulting from the absence in 2007 of costs associated with tropical storm Ernesto in September 2006.
(2) Decrease primarily due to charge-offs associated with our gas distribution operations.
(3) Increase in the year-to-date period reflects higher revenues largely attributable to an increase in the number of gas customers.

Dominion Energy

Presented below are operating statistics related to our Dominion Energy operations:

	Third Quarter			Year-To-Date		
	2007	2006	% Change	2007	2006	% Change
Gas transportation throughput (bcf)	134	128	5%	543	484	12%

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

	Third Quarter 2007 vs. 2006 Increase (Decrease)		Year-To-Date 2007 vs. 2006 Increase (Decrease)	
	Amount	EPS	Amount	EPS
(millions, except EPS)				
Producer services[1]	$ (25)	$(0.07)	$ (39)	$(0.11)
Gas transmission operations[2]	(13)	(0.04)	(10)	(0.03)
Electric transmission operations	(1)	—	3	0.01
Other	(2)	(0.01)	1	—
Share accretion	—	0.02	—	0.02
Change in net income contribution	$ (41)	$(0.10)	$ (45)	$(0.11)

(1) For the quarter, decrease is primarily due to unfavorable price changes on price risk management activities and lower mark-to-market gains on positions economically hedging gas and storage. Decrease in the year-to-date period is primarily related to unfavorable price changes due to reduced market volatility, as compared to the post-2005 hurricane market conditions in 2006.
(2) Decrease is primarily due to a decline in market center services and higher system fuel costs.

Dominion Generation

Presented below are operating statistics related to our Dominion Generation operations:

	Third Quarter			Year-To-Date		
	2007	2006	% Change	2007	2006	% Change
Electricity supplied (million mwhrs)						
Utility	**23.7**	23.0	3%	**64.7**	61.2	6%
Merchant	**12.7**	11.5	10	**34.2**	32.4	6
Degree days (electric utility service area):						
Cooling	**1,150**	1,119	3	**1,643**	1,528	8
Heating	**5**	15	(67)	**2,365**	2,056	15

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

	Third Quarter 2007 vs. 2006 Increase (Decrease)		Year-To-Date 2007 vs. 2006 Increase (Decrease)	
(millions, except EPS)	Amount	EPS	Amount	EPS
Virginia fuel expenses (1)	$165	$ 0.47	$ 75	$ 0.20
Merchant generation margin (2)	48	0.14	106	0.30
Ancillary service revenue	10	0.03	22	0.06
Regulated electric sales:				
Customer growth	7	0.02	16	0.05
Weather	(2)	(0.01)	25	0.07
Sales of emissions allowances	(28)	(0.08)	(39)	(0.11)
Energy supply margin	(8)	(0.02)	—	—
Interest expense	(6)	(0.02)	(15)	(0.04)
Outage costs (3)	(5)	(0.01)	(22)	(0.06)
Salaries, wages and benefits expense	(4)	(0.01)	(5)	(0.01)
Other	(27)	(0.08)	4	0.01
Share accretion	—	0.12	—	0.05
Change in net income contribution	$150	$ 0.55	$167	$ 0.52

(1) For the quarter and year-to-date periods, primarily reflects the reapplication of deferred fuel accounting effective July 1, 2007 for our utility generation operations. For the year-to-date period, the benefit is partially offset by increased consumption of fossil fuel and higher purchased power costs during the first six months of the year.

(2) Primarily reflects higher overall realized prices for our New England nuclear and fossil generating assets and higher volumes and capacity revenue for other fossil generation operations. Higher prices include implementation of new capacity markets in NEPOOL and PJM.

(3) For the quarter, primarily reflects an increase in the number of scheduled outage days for our utility generation operations, partially offset by lower scheduled outage days for merchant nuclear operations. For the year-to-date period, primarily reflects higher scheduled outage days for both utility and merchant generation operations.

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Dominion E&P

Presented below are operating statistics related to our E&P operations:

	Third Quarter 2007	Third Quarter 2006	% Change	Year-To-Date 2007	Year-To-Date 2006	% Change
Gas production (bcf)	**34.4**	75.8	(55)%	**183.1**	218.5	(16)%
Oil production (million bbls)	**0.8**	6.0	(87)	**11.2**	17.9	(37)
Average realized prices without hedging results:						
Gas (per mcf)[1]	**$ 5.89**	$ 6.34	(7)	**$ 6.59**	$ 6.86	(4)
Oil (per bbl)	**48.45**	58.59	(17)	**50.65**	57.27	(12)
Average realized prices with hedging results:						
Gas (per mcf)[1]	**$ 5.71**	$ 4.19	36	**$ 5.76**	$ 4.36	32
Oil (per bbl)	**41.70**	32.78	27	**37.24**	35.31	5
DD&A (unit of production rate per mcfe)	**$ 1.70**	$ 1.66	2	**$ 1.87**	$ 1.64	14

bbl(s) = barrel(s)

mcf = thousand cubic feet

mcfe = thousand cubic feet equivalent

(1) Excludes $60 million for the three months ended September 30, 2006 and $71 million and $203 million for the nine months ended September 30, 2007 and 2006, respectively, of revenue recognized under the VPP agreements, which were terminated in the second quarter of 2007, as described in Note 6 to our Consolidated Financial Statements.

Presented below, on an after-tax basis, are the key factors impacting Dominion E&P's net income contribution:

	Third Quarter 2007 vs. 2006 Increase (Decrease)		Year-To-Date 2007 vs. 2006 Increase (Decrease)	
(millions, except EPS)	Amount	EPS	Amount	EPS
Gas and oil — production[1]	(377)	(1.07)	(453)	(1.29)
Business interruption insurance[2]	(171)	(0.48)	(171)	(0.49)
Gas and oil — prices	$ 159	$ 0.45	$ 291	$ 0.83
DD&A	78	0.22	43	0.12
Operations and maintenance[3]	28	0.08	(39)	(0.11)
Interest expense	10	0.03	(4)	(0.01)
Other	14	0.04	32	0.09
Share accretion	—	0.01	—	0.03
Change in net income contribution	$(259)	$(0.72)	$(301)	$(0.83)

(1) Represents a decrease in gas and oil production related principally to the sale of our U.S. non-Appalachian E&P business.
(2) Decrease is due to the absence of business interruption insurance proceeds received in 2006 associated with the 2005 hurricanes.
(3) Lower operations and maintenance expenses for the quarter reflect overall decreases in lifting and transportation costs associated with the sale of our U.S. non-Appalachian E&P business. Higher operations and maintenance expenses in the year-to-date period, primarily reflecting the absence of a 2006 benefit from favorable changes in the fair value of certain gas and oil hedges that were de-designated following the 2005 hurricanes.

Included below are the volumes and weighted-average prices associated with hedges in place for our Appalachian operations and fixed-term overriding royalty interests formerly associated with the VPP agreements as of September 30, 2007 by applicable time period.

	Natural Gas	
Year	Hedged Production (bcf)	Average Hedge Price (per mcf)
2007	15.4	$ 7.10
2008	51.7	8.57
2009	6.7	8.43

Corporate

Presented below are the Corporate segment's after-tax results:

	Third Quarter			Year-To-Date		
(millions, except EPS)	2007	2006	$ Change	2007	2006	$ Change
Specific items attributable to operating segments	**$1,930**	$ (9)	$ 1,939	**$ 939**	$ (111)	$ 1,050
Peaker discontinued operations	**—**	(3)	3	**(28)**	(15)	(13)
Canadian E&P discontinued operations	**—**	2	(2)	**32**	28	4
Other corporate operations	**(189)**	(66)	(123)	**(228)**	(215)	(13)
Total net (expense) benefit	**$1,741**	$ (76)	$ 1,817	**$ 715**	$ (313)	$ 1,028
Earnings per share impact	**$ 5.44**	$(0.21)	$ 5.65	**$2.10**	$(0.90)	$ 3.00

Specific Items Attributable to Operating Segments

Corporate includes specific items attributable to our operating segments that have been excluded from profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments. See Note 22 to our Consolidated Financial Statements for discussion of these items.

Peaker Discontinued Operations

Year-To-Date 2007 vs. 2006

The increase in the loss from the discontinued operations of the Peaker facilities primarily reflects a $25 million loss on the sale of the Peaker facilities in March 2007, resulting largely from the allocation of $24 million of Generation reporting unit goodwill to the bases of the investments sold.

Other Corporate Operations

Third Quarter 2007 vs. 2006

Net expenses increased $123 million, primarily due to $267 million of charges ($163 million after-tax) related to the early retirement of outstanding debt associated with the completion of our debt tender offer in July 2007. The increase in net expenses also reflects an $86 million ($55 million after-tax) impairment charge related to certain DCI investments. These expenses were partially offset by higher income tax benefits in 2007, primarily reflecting the interim impact of changes to our estimated annual effective tax rate.

Year-To-Date 2007 vs. 2006

Net expenses increased $13 million, primarily reflecting charges related to the completion of our debt tender offer in July 2007, described above. These charges were partially offset by a $119 million tax benefit from the elimination of valuation allowances on deferred tax assets, representing federal and state tax loss carryforwards, since these losses will be utilized to offset taxable income generated from the sale of our non-Appalachian E&P business.

Selected Information—Energy Trading Activities

See *Selected Information-Energy Trading Activities* in MD&A included in our Annual Report on Form 10-K for the year ended December 31, 2006 for a discussion of our energy trading, hedging and marketing activities and related accounting policies. For additional discussion of trading activities, see *Market Risk Sensitive Instruments and Risk Management* in Item 3.

A summary of the changes in the unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes during the nine months ended September 30, 2007 follows:

(millions)	Amount
Net unrealized gain at December 31, 2006	$ 42
Contracts realized or otherwise settled during the period	(43)
Net unrealized gain at inception of contracts initiated during the period	—
Changes in valuation techniques	—
Other changes in fair value	15
Net unrealized gain at September 30, 2007	$ 14

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at September 30, 2007, is summarized in the following table based on the approach used to determine fair value and contract settlement or delivery dates:

	Maturity Based on Contract Settlement or Delivery Date(s)					
Source of Fair Value (millions)	Less than 1 year	1-2 years	2-3 years	3-5 years	In excess of 5 years	Total
Actively quoted[(1)]	$ (1)	$ 5	$ 6	$—	$ —	$ 10
Other external sources[(2)]	—	3	(1)	2	—	4
Total	$ (1)	$ 8	$ 5	$ 2	$ —	$ 14

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

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 sales of securities and additional long-term financing.

At September 30, 2007, we had $4.6 billion of unused capacity under our credit facilities, comprised of approximately $4.5 billion under our core credit facilities and $100 million available under a bilateral credit facility.

A summary of our cash flows for the nine months ended September 30, 2007 and 2006 is presented below:

(millions)	2007	2006
Cash and cash equivalents at January 1,[(1)]	$ 142	$ 146
Cash flows provided by (used in):		
Operating activities	2,283	3,486
Investing activities	10,814	(2,780)
Financing activities	(12,768)	(724)
Net increase (decrease) in cash and cash equivalents	329	(18)
Cash and cash equivalents at September 30,[(2)]	$ 471	$ 128

(1) 2007 amount includes $4 million of cash classified as held for sale in our Consolidated Balance Sheet.
(2) 2007 and 2006 amounts include $2 million of cash classified as held for sale in our Consolidated Balance Sheets.

Operating Cash Flows

For the nine months ended September 30, 2007, net cash provided by operating activities decreased by $1.2 billion as compared to the nine months ended September 30, 2006. The decrease was primarily due to a reduction in cash flow resulting from the sale of our non-Appalachian E&P business, the absence of business interruption insurance proceeds received in 2006, and higher income taxes paid. 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 in this report, our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007 and in our Annual Report on Form 10-K for the year-ended December 31, 2006.

Credit Risk

Our exposure to potential concentrations of credit risk results primarily from our energy marketing and price risk management activities. Presented below is a summary of our gross credit exposure as of September 30, 2007, 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. Gross credit exposure is calculated prior to the application of collateral.

(millions)	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
Investment grade[1]	$ 516	$ 1	$ 515
Non-investment grade[2]	26	—	26
No external ratings:			
Internally rated—investment grade[3]	155	5	150
Internally rated—non-investment grade[4]	67	—	67
Total	$ 764	$ 6	$ 758

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody's Investors Service (Moody's) and Standard & Poor's Ratings Services. The five largest counterparty exposures, combined, for this category represented approximately 35% of the total net credit exposure.
(2) The five largest counterparty exposures, combined, for this category represented approximately 2% of the total net credit exposure.
(3) The five largest counterparty exposures, combined, for this category represented approximately 15% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 2% of the total net credit exposure.

Investing Cash Flows

Significant cash flows provided by investing activities for the nine months ended September 30, 2007, included:

- $13.7 billion of net proceeds from the sale of our non-Appalachian E&P business;
- $696 million of proceeds from sales of securities held as investments in our nuclear decommissioning trusts; and
- $339 million of net proceeds from the sale of merchant generation facilities.

Cash flows provided by investing activities for the nine months ended September 30, 2007, were partially offset by:

- $1.8 billion of capital expenditures for the purchase and development of gas and oil producing properties, drilling and equipment costs and undeveloped lease acquisitions;
- $1.4 billion of capital expenditures, including environmental upgrades, routine capital improvements, purchase of nuclear fuel, and construction and improvements of gas and electric transmission and distribution assets; and
- $763 million for purchases of securities held as investments in our nuclear decommissioning trusts.

Financing Cash Flows and Liquidity

We rely on banks and capital markets as a significant source of funding for capital requirements not satisfied by cash provided by the companies' operations. As discussed further in the *Credit Ratings and Debt Covenants* section, our ability to borrow funds or issue securities and the return demanded by investors are affected by the issuing company's credit ratings. In addition, the raising of external capital is subject to meeting certain regulatory requirements, including registration with the SEC and, in the case of Virginia Power, approval by the Virginia Commission.

Significant financing activities for the nine months ended September 30, 2007 included:

- $5.8 billion for the repurchase of common stock, primarily due to the completion of our equity tender offer in August 2007;
- $5.4 billion for the repayment of long-term debt and notes payable, largely resulting from the completion of our debt tender offer in July 2007;
- $2.3 billion for the repayment of short-term debt; and
- $704 million of dividend payments; partially offset by
- $1.2 billion from the issuance of long-term debt.

See Note 17 to our Consolidated Financial Statements for further information regarding our credit facilities, liquidity and significant financing transactions, including our debt and equity tender offers.

Credit Ratings and Debt Covenants

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. In the *Credit Ratings* and *Debt Covenants* sections of MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006, we discussed the use of capital markets by Virginia Power, CNG and us (the Dominion Companies), as well as the impact of credit ratings on the accessibility and costs of using these markets. In addition, these sections of MD&A discussed various covenants present in the enabling agreements underlying the Dominion Companies' debt. As a result of the merger of CNG with Dominion, all of CNG's former rights and obligations under its indentures have been assumed by Dominion. Subsequent to the merger, Moody's lowered its rating of CNG Senior Unsecured debt from Baa1 to Baa2 to equal their rating of Dominion's Senior Unsecured debt.

In June 2006 and September 2006, we executed Replacement Capital Covenants (RCCs) in connection with our offering of $300 million of 2006 Series A Enhanced Junior Subordinated Notes due 2066 (June hybrids) and $500 million of 2006 Series B Enhanced Junior Subordinated Notes due 2066 (September hybrids), respectively. We initially designated the 8.4% Capital Securities of Dominion Resources Capital Trust III as covered debt for purposes of the RCCs. However, due to our acquisition of most of these securities in our debt tender offer in July 2007, they ceased to be eligible as covered debt for the RCCs. Under the terms of the RCCs, we are required under certain circumstances to change the series of our debt designated as covered debt under the RCCs. In the third quarter of 2007, we designated the September hybrids as covered debt under the June hybrids' RCC and designated the June hybrids as covered debt under the September hybrids' RCC.

We monitor the covenants on a regular basis in order to ensure that events of default will not occur. As of September 30, 2007 there have been no events of default under our debt covenants. Other than the change in covered debt for the RCCs discussed above, as of September 30, 2007, there have been no changes to our debt covenants.

Future Cash Payments for Contractual Obligations

As of September 30, 2007, there have been no material changes outside the ordinary course of business to the contractual obligations disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006, with the exception of the following.

In connection with the sales of our non-Appalachian E&P operations, the purchasers have indemnified us and assumed our contractual obligations associated with these operations. Additionally, we used some of the after-tax proceeds from these dispositions to reduce our outstanding debt. As a result of these transactions, our contractual obligations at December 31, 2006 have been reduced as follows:

(millions)	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Total cash payments	$ 7,017	$6,459	$ 5,418	$ 23,682	$42,576
Less: non-Appalachian E&P operations	(218)	(148)	(79)	(71)	(516)
Less: debt reduction	(309)	(553)	(1,406)	(3,168)	(5,436)
Total cash payments as adjusted	$ 6,490	$5,758	$ 3,933	$ 20,443	$36,624

Planned Capital Expenditures

As of September 30, 2007, our planned capital expenditures for 2008 are expected to total approximately $3.5 billion. The decrease, as compared to the amounts originally forecasted in our Annual Report on Form 10-K for the year ended December 31, 2006, primarily reflects the sale of our non-Appalachian E&P operations, partially offset by an increase in capital spending associated with the need for additional generation in our electric utility service territory. Our planned capital expenditures include capital projects that are subject to board approval. We expect to fund our capital expenditures with cash from operations and a combination of sales of securities and short-term borrowings.

Use of Off-Balance Sheet Arrangements

Following the closing of the sale of our offshore E&P operations in July 2007, we have been released from all obligations under the off-balance sheet arrangements related to the Thunder Hawk facility and an ultra-deepwater drilling rig discussed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006.

With the exception of these items, as of September 30, 2007, there have been no material changes in the off-balance sheet arrangements disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006.

Future Issues and Other Matters

The following discussion of future issues and other information includes current developments of previously disclosed matters and new issues arising during the period covered by and subsequent to our Consolidated Financial Statements. This section should be read in conjunction with *Future Issues and Other Matters* in our Annual Report on Form 10-K for the year ended December 31, 2006 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007.

Common Stock Dividend Increase and Stock Split

On October 26, 2007, our board of directors approved an increase in our quarterly common stock dividend rate. The quarterly dividend rate was increased to 79 cents per share, an 11% increase over our existing quarterly dividend rate of 71 cents per share. Stated as an annual rate, the board's action increases the dividend rate from $2.84 per share to $3.16 per share.

In a separate matter, the board of directors approved a two-for-one stock split and an increase in the number of shares of common stock the Company is authorized to issue from 500 million to 1 billion. Shareholders of record on November 9, 2007, will receive one additional share of common stock for each share held at the close of business on that date; however, the proportionate interest that a shareholder owns in the Company will not change as a result of the stock split. The additional shares will be distributed on or after November 19, 2007. Based on shares outstanding at September 30, 2007, upon the completion of the stock split Dominion will have approximately 575 million shares of common stock outstanding.

Dividends are payable on December 20, 2007, to shareholders of record on November 30, 2007. The dividend payment will be made after the stock split. As a result of the timing, shareholders of record on November 30, 2007, will receive an annual dividend rate on a post-split basis of $1.58 per share or 39.5 cents per share on a quarterly basis.

Regulatory Approval of Sale of Peoples and Hope

In March 2006, Peoples and Equitable Resources, Inc. (Equitable) filed a joint petition with the Pennsylvania Public Utility Commission (Pennsylvania Commission) seeking approval of the purchase by Equitable of all of the stock of Peoples and Hope. In April 2006, Hope and Equitable filed a joint petition seeking West Virginia Public Service Commission (West Virginia Commission) approval of the purchase by Equitable of all of the stock of Hope. In April 2007, the Pennsylvania Commission approved a joint settlement approving the sale in Pennsylvania. Following the approval of the sale of Peoples by the Pennsylvania Commission, the Federal Trade Commission (FTC) filed an action in federal court seeking to block the transaction. Such action was denied and the case is currently on appeal by the FTC in the 3rd U.S. Circuit Court of Appeals. A decision in such case is expected in November 2007. In West Virginia, the regulatory process had been delayed by the West Virginia Commission's decision to include certain gas purchasing practices in its examination of the sale. However, in July 2007, the West Virginia Commission ordered that the matter of the acquisition of Hope by Equitable and the matter related to certain gas purchasing practices of Hope be separated allowing the West Virginia Commission to move forward with its review of the sale. The West Virginia Commission has established a briefing schedule that is expected to result in a final decision regarding the sale in late 2007, unless the parties reach an earlier settlement. After November 1, 2007, either Dominion or Equitable is entitled to terminate the transaction, although at this time neither party has indicated its intention to exercise its termination right.

Transmission Expansion Plan

Each year, as part of PJM's Regional Transmission Expansion Plan (RTEP) process, reliability projects are authorized. In June 2006, PJM, through the RTEP process, authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects. The first project is an approximately 270-mile 500-kilovolt (kV) transmission line from southwestern Pennsylvania to northern Virginia, of which we will construct approximately 65 miles in Virginia and a subsidiary of Allegheny Energy, Inc. (Trans-Allegheny Interstate Line Company) will construct the remainder. The second project is an approximately 60-mile 500-kV transmission line that we will construct in southeastern Virginia. 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 will be subject to applicable state and federal permits and approvals. In April 2007, we, along with Trans-Allegheny Interstate Line Company, filed an application with the Virginia Commission requesting approval of the proposed construction of the

65-mile transmission line in northern Virginia. Evidentiary hearings on this application will be held in February 2008. In May 2007, we filed an application with the Virginia Commission requesting approval of the proposed construction of the 60-mile transmission line in southeastern Virginia. Evidentiary hearings will be held on this application in February 2008.

Generation Expansion

Based on available generation capacity and current estimates of growth in customer demand in our utility service area, we will need additional generation over the next 10 years. As a result, in April 2007, we filed an application with the Virginia Commission requesting approval to add two 150 Mw natural gas-fired electric generating units (Units 3 and 4) to our Ladysmith Power Station to supply electricity during periods of peak demand. The facility is expected to be in operation by August 2008, at an estimated cost of $135 million. The Virginia Commission approved the application on August 24, 2007, and construction has commenced. Approval by the North Carolina Commission for a related affiliate transaction is still pending.

On September 13, 2007, we filed a Petition for Reconsideration requesting that the Virginia Commission modify its order of August 24, 2007 for the limited purpose of continuing the docket generally to provide us with an opportunity to file supplemental information supporting approval of a fifth combustion turbine (Unit 5) at the existing Ladysmith generating facility. The Virginia Commission granted the petition for that limited purpose on September 14, 2007 and we plan to file for approval of Unit 5 in early November 2007.

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 to be located in Wise County, Virginia. We also requested approval to continue to accrue an allowance for funds used during construction until capped rates end and, beginning January 1, 2009, receive current recovery of financing costs including a return on common equity of 11.75% together with a 200 basis point enhancement through a rate adjustment clause. Pending regulatory approval and necessary permits, the facility is expected to be in operation by 2012 at an estimated cost of approximately $1.6 billion, at that time. A public hearing is scheduled for January 8, 2008.

PJM Rate Design

In May 2005, the Federal Energy Regulatory Commission (FERC) issued an order finding that PJM's existing transmission service rate design may not be just and reasonable, and ordered an investigation and hearings into the matter. In April 2007, FERC reaffirmed PJM's existing transmission service rate design. FERC also determined that the costs of new PJM-planned transmission facilities that operate at or above 500 kV will be allocated on a PJM region-wide basis, while the costs of new PJM-planned facilities that operate below 500 kV will be assigned to zones within the PJM region based on a new model to be developed in further proceedings. Rehearing of the FERC order was sought in May 2007. We cannot predict whether the FERC decision with regard to the allocation of costs of facilities operating at or above 500 kV will be modified upon rehearing. In September 2007, a settlement proposal was filed at FERC with regard to the allocation of costs of PJM-planned facilities that operate below 500 kV. Such settlement proposal is still pending.

Ohio Rate Case

In August 2007, The East Ohio Gas Company (East Ohio) filed an application to increase base rates. In this rate case, East Ohio requests approval of an increase in operating revenues of over $73 million to provide a rate of return on rate base of 8.72%. As part of its request, East Ohio is proposing to install automated meter reading devices for all of its 1.2 million customers over a 5-year period and to spend up to an additional $5.5 million per year over a three-year period on demand side management programs if the Public Utilities Commission of Ohio approves a decoupling mechanism that would automatically adjust base rates in order to maintain base rate revenues per customer at the level approved in the rate case. In addition, East Ohio is proposing to expand its gross receipts tax rider to apply to all amounts billed for services, rather than just gas cost recoveries, thereby excluding gross receipts tax from base rates.

Depreciation Study

In October 2007, we revised the depreciation rates for our utility generation assets to reflect the results of a new depreciation study, which incorporates changes in service life estimates and the property, plant and equipment accounting policy changes that were made upon the reapplication of SFAS No. 71, as discussed in Note 5 to our Consolidated Financial Statements. This change is expected to increase annual depreciation expense by approximately $54 million ($33 million after-tax) prospectively.

Environmental Matters

Virginia Energy Plan

The Virginia Energy Plan, released by the Governor of Virginia in September 2007, set a goal of reducing greenhouse gas emissions statewide back to 2000 levels by 2025, and has called for the formation of a Commission on Climate Change to develop a plan to achieve this goal. Until this goal results in legislative or regulatory action, the outcome in terms of specific requirements and timing is uncertain, and we cannot predict the financial impact on our operations at this time.

Clean Air Act Compliance

Illinois has finalized regulations to implement the Clean Air Interstate Rule with requirements more strict than the federal rule. The Indiana Air Pollution Control Board has approved adoption of the federal Clean Air Mercury Rule, with only minor changes. Projected capital expenditures at our affected facilities remain consistent with the estimates provided in our Annual Report on Form 10-K for the year ended December 31, 2006.

Clean Water Act Compliance

In October 2003, the EPA and the Massachusetts Department of Environmental Protection each issued new National Pollutant Discharge Elimination System (NPDES) permits for the Brayton Point Power Station (Brayton Point). The new permits contained identical conditions that in effect require the installation of cooling towers to address concerns over the withdrawal and discharge of cooling water. In November 2003, appeals were filed with the EPA Environmental Appeals Board (EAB) and the Division of Administrative Law Appeals in Massachusetts, and both permits were stayed. In February 2006, the EAB remanded a portion of the EPA's NPDES permit to the EPA for reconsideration. In November 2006, EPA issued its determination on remand regarding four remaining issues appealed by Brayton Point concerning its NPDES permit. In January 2007, Brayton Point appealed three of those issues to the EPA EAB. In September 2007, EAB denied review of those issues, thus concluding the EPA's review process. In October 2007, Brayton Point filed a motion with the Regional Administrator for the U.S. EPA seeking a stay of the effectiveness of the Station's NPDES permit. On October 26, 2007, the Regional Administrator denied the motion. Also on October 26, 2007, Brayton Point filed an appeal of the permit with the U.S. Court of Appeals. On October 30, 2007, Brayton Point filed a motion requesting the U.S. Court of Appeals stay the permit pending resolution of its petition for review. EPA has agreed to a temporary stay until November 16, 2007, to allow for briefing of the motion for stay. Until the appeals process is completed, the outcome of this matter cannot be predicted. However, should the appeals process result in an unfavorable outcome, we would likely be required to install cooling towers, which could result in material capital expenditures in future years.

DOMINION RESOURCES, INC.
ITEM 3. 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 I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-Q. The reader's attention is directed to those paragraphs for discussion of various risks and uncertainties that may affect our future.

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, foreign currency exchange rates and equity security prices as described below. Commodity price risk is present in our electric operations, energy marketing and trading operations, and gas and oil production and procurement operations due to the exposure to market shifts in prices received and paid for electricity, natural gas, oil and other commodities. We use commodity derivative contracts to manage price risk exposures for these operations. Interest rate risk is generally related to our outstanding debt. We are exposed to foreign currency exchange rate risks related to our purchases of fuel and fuel services denominated in foreign currencies. In addition, we are exposed to equity price risk through various portfolios of 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, interest rates and foreign currency exchange rates.

Commodity Price Risk

We manage price risk associated with purchases and sales of electricity, natural gas, oil, and certain other commodities using commodity-based financial derivative instruments held for non-trading purposes. As part of our strategy to market energy and to manage related risks, we also hold commodity-based financial derivative instruments for trading purposes.

The derivatives used to manage risk are executed within established policies and procedures and include instruments such as futures, forwards, swaps and options that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the fair value 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 actively quoted market prices.

A hypothetical 10% unfavorable change in market prices of our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $274 million and $597 million as of September 30, 2007 and December 31, 2006, respectively. The decrease is primarily due to the execution of offsetting derivatives related to the divestiture of our non-Appalachian E&P business. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $5 million and $3 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of September 30, 2007 and December 31, 2006, 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. Net losses from commodity derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction, such as revenue from sales.

Foreign Currency Exchange Risk

We manage our foreign currency exchange risk exposure associated with anticipated future purchases of nuclear fuel processing services denominated in foreign currencies by utilizing currency forward contracts. As a result of holding these contracts as hedges, our exposure to foreign currency risk is minimal. A hypothetical 10% decrease in relevant foreign exchange rates would have resulted in a decrease of approximately $2 million and $3 million in the fair value of currency forward contracts held by us at September 30, 2007 and December 31, 2006, respectively.

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 September 30, 2007, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $7 million. A hypothetical 10% increase in market interest rates, as determined at December 31, 2006, would have resulted in a decrease in annual earnings of approximately $25 million.

In addition, we retain ownership of mortgage investments, including subordinated bonds and interest-only residual assets retained from securitizations of mortgage loans originated and purchased in prior years. Note 27 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006 discusses the impact of changes in value of these investments.

Investment Price Risk

We are subject to investment price risk due to marketable securities held as investments in decommissioning trust funds. These marketable securities are managed by third-party investment managers and are reported in our Consolidated Balance Sheets at fair value. We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $35 million and $59 million for the nine months ended September 30, 2007 and 2006, respectively, and $63 million for the year ended December 31, 2006. We recorded, in AOCI, unrealized gains on these investments of $69 million for the nine months ended September 30, 2007, and net unrealized gains on these investments of $84 million for the nine months ended September 30, 2006. For the year ended December 31, 2006, we recorded, in AOCI, unrealized gains on these investments of $194 million.

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

We also sponsor employee pension and other postretirement benefit plans that hold investments in trusts to fund benefit payments. To the extent that the values of investments held in these trusts decline, the effect will be reflected in our recognition of the periodic cost of such employee benefit plans and the determination of the amount of cash to be contributed to the employee benefit plans.

ITEM 4. CONTROLS AND PROCEDURES

Senior management, including the Chief Executive Officer and Chief Financial Officer, 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, the Chief Executive Officer and Chief Financial Officer have concluded that Dominion's disclosure controls and procedures are effective.

In accordance with the purchase and sale agreements related to the divestiture of certain non-Appalachian E&P operations, Dominion agreed to provide transition services to buyers for a period extending into 2008, including services that affect internal controls over financial reporting. As such, certain transaction processing, financial reporting and information technology controls related to these non-Appalachian E&P operations were temporarily added or modified during the period to help support these services. For further discussion related to the divestiture, see Notes 1 and 6 to our Consolidated Financial Statements. Apart from this, there have been no significant changes in Dominion's internal control over financial reporting during the quarter ended September 30, 2007, that have materially affected, or are reasonably likely to materially affect, Dominion's internal control over financial reporting.

DOMINION RESOURCES, INC.
PART II. OTHER INFORMATION

ITEM 1. 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 *Future Issues and Other Matters* in MD&A for discussions on various environmental and other regulatory proceedings to which we are a party.

In October 2003, the Environmental Protection Agency (EPA) and the Massachusetts Department of Environmental Protection each issued new National Pollutant Discharge Elimination System (NPDES) permits for the Brayton Point Power Station (Brayton Point). The new permits contained identical conditions that in effect require the installation of cooling towers to address concerns over the withdrawal and discharge of cooling water. In November 2003, appeals were filed with the EPA Environmental Appeals Board (EAB) and the Division of Administrative Law Appeals in Massachusetts, and both permits were stayed. In February 2006, the EAB remanded a portion of the EPA's NPDES permit to the EPA for reconsideration. In November 2006, EPA issued its determination on remand regarding four remaining issues appealed by Brayton Point concerning its NPDES permit. In January 2007, Brayton Point appealed three of those issues to the EPA EAB. In September 2007, EAB denied review of those issues, thus concluding the EPA's review process. In October 2007, Brayton Point filed a motion with the Regional Administrator for the U.S. EPA seeking a stay of the effectiveness of the Station's NPDES permit. On October 26, 2007, the Regional Administrator denied the motion. Also on October 26, 2007, Brayton Point filed an appeal of the permit with the U.S. Court of Appeals. On October 30, 2007, Brayton Point filed a motion requesting the U.S. Court of Appeals stay the permit pending resolution of its petition for review. EPA has agreed to a temporary stay until November 16, 2007, to allow for briefing of the motion for stay. Until the appeals process is completed, the outcome of this matter cannot be predicted.

In December 2006 and January 2007, we submitted self-disclosure notifications to EPA Region 8 regarding three E&P facilities in Utah that have potentially violated Clean Air Act permitting requirements. On July 31, 2007, a third party purchased Dominion's E&P assets in Utah including these facilities and under the purchase and sale agreement the third party assumed responsibility for the resolution of any enforcement action or Consent Decree, including penalties.

In March 2006, Peoples and Equitable filed a joint petition with the Pennsylvania Commission seeking approval of the purchase by Equitable of all of the stock of Peoples and Hope. In April 2006, Hope and Equitable filed a joint petition seeking West Virginia Commission approval of the purchase by Equitable of all of the stock of Hope. In April 2007, the Pennsylvania Commission approved a joint settlement approving the sale in Pennsylvania. Following the approval of the sale of Peoples by the Pennsylvania Commission, the FTC filed an action in federal court seeking to block the transaction. Such action was denied and the case is currently on appeal by the FTC in the 3rd U.S. Circuit Court of Appeals. A decision in such case is expected in November 2007. In West Virginia, the regulatory process had been delayed by the West Virginia Commission's decision to include certain gas purchasing practices in its examination of the sale. However, in July 2007, the West Virginia Commission ordered that the matter of the acquisition of Hope by Equitable and the matter related to certain gas purchasing practices of Hope be bifurcated allowing the West Virginia Commission to move forward with its review of the sale. The West Virginia Commission has established a briefing schedule that is expected to result in a final decision regarding the sale in late 2007, unless the parties reach an earlier settlement.

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 risk factors in our Annual Report on Form 10-K for the year ended December 31, 2006 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007, which factors should be taken into consideration when reviewing the information contained in this report. With the exception of the risk factor below, there have been no material changes with regard to the risk factors previously disclosed in our most recent Form 10-K and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007. 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.

The sale of most of our E&P assets is expected to reduce our operating revenues and may not yield the benefits that we expect. Since June 2007 we have sold approximately 5.5 Tcfe equivalent of proved natural oil and gas reserves for approximately $13.9 billion. This sale of most of our E&P assets is expected to reduce our operating revenues in the near-term and may not yield the benefits that we expect.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The table below provides certain information with respect to our purchases of our common stock:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased(1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased under the Plans or Programs
7/1/07-7/31/07	7,445	$ 87.16	N/A	31,525,074 shares/$3.07 billion
8/1/07-8/31/07	2,452,135	86.52	2,434,600	29,090,474 shares/$2.86 billion
9/1/07-9/30/07	2,109,308	85.25	2,104,900	26,985,574 shares/$2.68 billion
Total	4,568,888	$ 85.94	4,539,500	26,985,574 shares/$2.68 billion

(1) Amount includes registered shares tendered by employees to satisfy tax withholding obligations on vested restricted stock.

In addition to the table above, in August 2007, we completed an equity tender offer, approved by our Board of Directors, for the purchase of approximately 57,751,767 shares at a price of $91 per share, for a total cost of approximately $5.3 billion, excluding fees and expenses related to the tender.

ITEM 6. EXHIBITS

(a) Exhibits:

3.1 Articles of Incorporation as in effect August 9, 1999, as amended March 12, 2001 (Exhibit 3.1, Form 10-K for the year ended December 31, 2002, File No. 1-8489, incorporated by reference).

3.2 Amended and Restated Bylaws effective on June 20, 2007 (Exhibit 3.1, Form 8-K filed June 22, 2007, File No. 1-8489, incorporated by reference).

4.1 Dominion Resources, Inc. 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.

4.2 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, dated June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 3, 1999, File No.1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K, dated October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); and Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated January 24, 2002, incorporated by reference); Seventh Supplemental Indenture dated September 1, 2002 (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, 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 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).

12 Ratio of earnings to fixed charges (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 (filed herewith).

99 Condensed consolidated earnings statements (unaudited) (filed herewith).

SIGNATURE

Pursuant to the requirements 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.

DOMINION RESOURCES, INC.
Registrant

November 1, 2007

/s/ Thomas P. Wohlfarth
Thomas P. Wohlfarth
Senior Vice President and Chief Accounting Officer

Exhibit 12

Dominion Resources Inc. and Subsidiaries
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

	Nine Months Ended September 30, 2007 (a)	Twelve Months Ended September 30, 2007 (b)	Years Ended December 31, 2006 (c)	2005 (d)	2004 (e)	2003 (f)	2002
Earnings, as defined:							
Earnings from continuing operations before income taxes and minority interests in consolidated subsidiaries	$ 3,986	$ 4,359	$2,463	$1,606	$1,951	$1,494	$2,008
Distributed income from unconsolidated investees, less equity in earnings	(15)	(23)	(16)	(15)	3	(5)	24
Fixed charges included in the determination of net income	1,033	1,315	1,095	999	951	991	962
Total earnings, as defined	$ 5,004	$ 5,651	$3,542	$2,590	$2,905	$2,480	$2,994
Fixed charges, as defined:							
Interest charges	$ 1,057	$ 1,360	$1,164	$1,052	$ 986	$1,067	$1,036
Rental interest factor	47	62	58	53	40	27	27
Total fixed charges, as defined	$ 1,104	$ 1,422	$1,222	$1,105	$1,026	$1,094	$1,063
Ratio of Earnings to Fixed Charges	**4.53**	**3.97**	**2.90**	**2.34**	**2.83**	**2.27**	**2.82**

(a) Earnings for the nine months ended September 30, 2007 include a $3.6 billion gain from the disposition of our non-Appalachian exploration and production (E&P) business, partially offset by $1 billion of charges related to the disposition which are comprised of $544 million related to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges, $171 million primarily related to the settlement of volumetric production payment agreements, $242 million of charges related to the early retirement of debt, and $77 million of employee-related expenses. Earnings for the period also include $416 million of impairment charges related to our generation assets, including a $387 million impairment of the partially-completed Dresden generation facility; a $236 million charge due to the expected termination of a power sales agreement at our State Line generating facility; $86 million of impairment charges related to Dominion Capital, Inc. (DCI) assets; $53 million of charges related to litigation reserves, and $26 million of charges related to other items. Fixed charges for the nine months ended September 30, 2007 include $234 million of costs related to the early retirement of debt associated with our debt tender offer completed in July 2007. Excluding these items from the calculation would result in a lower ratio of earnings to fixed charges for the nine months ended September 30, 2007.

(b) Earnings for the twelve months ended September 30, 2007 include a $3.6 billion gain from the disposition of our non-Appalachian E&P business, partially offset by $1 billion of charges related to the disposition which are comprised of $544 million related to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges, $171 million primarily related to the settlement of volumetric production payment agreements, $242 million of charges related to the early retirement of debt, and $84 million of employee-related expenses. Earnings for the period also include $416 million of impairment charges related to our generation assets, including a $387 million impairment of the partially-completed Dresden generation facility; a $236 million charge due to the expected termination of a power sales agreement at our State Line generating facility; $86 million of impairment charges related to DCI assets; $53 million of charges related to litigation reserves; $42 million of impairment charges related to securities held in nuclear decommissioning trusts; a $27 million charge resulting from the termination of a pipeline project in West Virginia, and $6 million of net charges related to other items. Fixed charges for the twelve months ended September 30, 2007 include $234 million of costs related to the early retirement of debt associated with our debt tender offer completed in July 2007. Excluding these items from the calculation would result in a lower ratio of earnings to fixed charges for the twelve months ended September 30, 2007.

(c) Earnings for the twelve months ended December 31, 2006 include $189 million of charges related to the pending sale of two natural gas distribution utilities, The Peoples Natural Gas Company and Hope Gas, Inc., including $166 million resulting from the write-off of certain regulatory assets, $90 million of impairment charges related to DCI assets, a $60 million charge due to an adjustment eliminating the application of hedge accounting related to certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts, a $27 million charge resulting from the termination of a pipeline project in West Virginia, a $26 million impairment charge resulting from a change in method of assessing other-than-temporary decline in the fair value of certain securities, $17 million of incremental charges related to the 2005 hurricanes, and $9 million of net charges related to other items. Excluding these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2006.

(d) Earnings for the twelve months ended December 31, 2005 include a $423 million charge reflecting the de-designation of hedge contracts resulting from the delay of natural gas and oil production following Hurricanes Katrina and Rita, $73 million in charges resulting from the termination of certain long-term power purchase contracts, $21 million in net charges related to trading activities discontinued in 2004, including the Batesville long-term power-tolling contract divested in the second quarter of 2005 and other activities, $35 million of impairment charges related to DCI assets, a $76 million charge related to miscellaneous asset impairments, a $28 million charge related to expenses following Hurricanes Katrina and Rita and $5 million of charges related to other items. Excluding these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2005.

(e) Earnings for the twelve months ended December 31, 2004 include $76 million of impairment charges related to Dominion's investment in and planned divestiture of DCI, a $23 million benefit associated with the disposition of certain assets held for sale, an $18 million benefit from the reduction of accrued expenses associated with Hurricane Isabel restoration activities, $96 million of losses related to the discontinuance of hedge accounting for certain oil hedges and subsequent changes in the fair value of those hedges during the third quarter following Hurricane Ivan, $71 million in charges resulting from the termination of certain long-term power purchase contracts, a $184 million charge related to the Batesville long-term power-tolling contract divested in the second quarter of 2005, and $22 million of charges related to net legal settlements and other items. Excluding these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2004.

(f) Earnings for the twelve months ended December 31, 2003 include a $134 million impairment of DCI assets, $28 million for severance costs related to workforce reductions, an $84 million impairment of certain assets held for sale, $197 million for restoration expenses related to Hurricane Isabel, a $105 million charge related to the termination of a power purchase contract, $64 million in charges for the restructuring and termination of certain electric sales contracts and a $144 million charge related to our investment in Dominion Telecom including impairments, the cost of refinancings, and reallocation of equity losses. Excluding these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2003.

Exhibit 31.1

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

1. I have reviewed this report on Form 10-Q of Dominion Resources, Inc.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 1, 2007

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
President and Chief Executive Officer

Exhibit 31.2

I, Thomas N. Chewning, certify that:

1. I have reviewed this report on Form 10-Q of Dominion Resources, Inc.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 1, 2007

/s/ Thomas N. Chewning
Thomas N. Chewning
Executive Vice President and Chief Financial Officer

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of Dominion Resources, Inc. (the Company), certify that:

1. the Quarterly Report on Form 10-Q for the quarter ended September 30, 2007 (the "Report") of the Company to which this certification is an exhibit fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)).

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of September 30, 2007 and for the period then ended.

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
President and Chief Executive Officer
November 1, 2007

/s/ Thomas N. Chewning
Thomas N. Chewning
Executive Vice President and Chief Financial Officer
November 1, 2007

DOMINION RESOURCES, INC.

CONDENSED CONSOLIDATED EARNINGS STATEMENT
(Unaudited)

(millions)	Twelve Months Ended September 30, 2007
Operating Revenue	$ 15,902
Operating Expenses	10,468
Income from operations	5,434
Other income	163
Interest and related charges	1,238
Income before income tax expense	4,359
Income tax expense	1,752
Minority interest	8
Income from continuing operations before extraordinary item	2,599
Extraordinary item (net of income tax benefit of $101)	(158)
Loss from discontinued operations (including income tax expense of $26)	(169)
Net Income	$ 2,272
Earnings Per Common Share—Basic	
Income from continuing operations before extraordinary item	$ 8.18
Extraordinary item	(0.50)
Loss from discontinued operations	(0.53)
Net income	$ 7.15
Earnings Per Common Share—Diluted	
Income from continuing operations before extraordinary item	$ 8.13
Extraordinary item	(0.50)
Loss from discontinued operations	(0.53)
Net income	$ 7.10

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2006

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 000-50039

OLD DOMINION ELECTRIC COOPERATIVE
(Exact name of Registrant as specified in its charter)

VIRGINIA (State or other jurisdiction of incorporation or organization)	**23-7048405** (I.R.S. employer identification no.)
4201 Dominion Boulevard, Glen Allen, Virginia (Address of principal executive offices)	**23060** (Zip code)

(804) 747-0592
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act: NONE

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

6.25% 2001 Series A Bonds due 2011

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act? Yes ☐ No ☒

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

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

Indicate by check mark whether the Registrant is a large accelerated filer, ☐an accelerated filer or a non-accelerated filer (as defined in Exchange Act Rule 12b-2). Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

Indicate by check mark whether the Registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant. NONE

Indicate the number of shares outstanding of each of the Registrant's classes of Common Stock, as of the latest practicable date. The Registrant is a membership corporation and has no authorized or outstanding equity securities.

Documents incorporated by reference: NONE

OLD DOMINION ELECTRIC COOPERATIVE

2006 ANNUAL REPORT ON FORM 10-K

PART I

ITEM 1. BUSINESS

General

Old Dominion Electric Cooperative ("ODEC" or "we" or "our") was incorporated under the laws of the Commonwealth of Virginia in 1948 as a not-for-profit power supply cooperative. We were organized for the purpose of supplying the power our member distribution cooperatives require to serve their customers on a cost-effective basis. Through our member distribution cooperatives, we served more than 535,000 retail electric consumers (meters) representing a total population of approximately 1.3 million people in 2006. We provide this power pursuant to long-term, all-requirements wholesale power contracts. See "—Member Distribution Cooperatives" below.

We supply our member distribution cooperatives' power requirements, consisting of capacity requirements and energy requirements, through a portfolio of resources including generating facilities, power purchase contracts, and forward, short-term and spot market energy purchases. Our generating facilities are fueled by a mix of coal, nuclear, natural gas, and fuel oil. See "—Power Supply Resources" below and "Properties" in Item 2 for a description of these resources.

We are owned entirely by our members, which are the primary purchasers of the power we sell. We have two classes of members. Our Class A members are twelve customer-owned electric distribution cooperatives that sell electric service to their customers in 70 counties throughout Virginia, Delaware, Maryland, and a small portion of West Virginia. Our sole Class B member is TEC Trading, Inc. ("TEC"), a taxable corporation owned by our member distribution cooperatives. TEC was formed for the primary purposes of purchasing power from us to sell in the market, acquiring natural gas to supply our three combustion turbine facilities, and taking advantage of other power-related trading opportunities in the market. TEC does not engage in speculative trading. See "—TEC" below.

Our member distribution cooperatives primarily serve suburban, rural and recreational areas. These areas predominantly reflect stable growth in residential capacity and energy requirements both in terms of power sales and number of customers. See "—Members' Service Territories and Customers" below. Under state restructuring legislation, nearly all customers of our member distribution cooperatives are able to select their power suppliers. The member distribution cooperatives are the exclusive providers of distribution services and, at least initially, the default providers of power to their customers in their service territories. See "Regulation—Competition" below.

As a not-for-profit electric cooperative, we are currently exempt from federal income taxation under Section 501(c)(12) of the Internal Revenue Code of 1986, as amended. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Tax Status" in Item 7 for a further discussion of our tax status.

We are not a party to any collective bargaining agreement. We had 103 employees as of March 1, 2007.

Our principal executive offices are located in the Innsbrook Corporate Center, at 4201 Dominion Boulevard, Glen Allen, Virginia 23060-6721. Our telephone number is (804) 747-0592.

Cooperative Structure

In general, a cooperative is a business organization owned by its members, which are also either the cooperative's wholesale or retail customers. Cooperatives are designed to give their members the opportunity to satisfy their collective needs in a particular area of business more effectively than if the members acted independently. As not-for-profit organizations, cooperatives are intended to provide services to their members on a cost-effective basis, in part by eliminating the need to produce profits or a return on equity in excess of required margins. Margins not distributed to members constitute patronage capital, a cooperative's principal source of equity. Patronage capital is held for the account of the members without interest and returned when the board of directors of the cooperative deems it appropriate to do so.

We are a power supply cooperative. Electric distribution cooperatives form power supply cooperatives to acquire power supply resources, typically through the construction of generating facilities or the development of other power purchase arrangements, at a lower cost than if they were acquiring those resources alone.

Our Class A members are electric distribution cooperatives. Electric distribution cooperatives own and maintain nearly half of the distribution lines in the United States and serve three-quarters of the United States' land mass. There are currently approximately 870 electric distribution cooperatives in the United States. Historically, electric distribution cooperatives have owned and operated distribution systems to supply the power requirements of their retail customers. See also "—Competition and Changing Regulations" below.

Member Distribution Cooperatives

General

Our member distribution cooperatives provide electric services, consisting of power supply, transmission services, and distribution services (including metering and billing) to residential, commercial, and industrial customers in 70 counties in Virginia, Delaware, Maryland, and West Virginia. The member distribution cooperatives' distribution business involves the operation of substations, transformers, and electric lines that deliver power to customers. Three of our member distribution cooperatives provide electric services on the Delmarva Peninsula: A&N Electric Cooperative in Virginia, Choptank Electric Cooperative in Maryland, and Delaware Electric Cooperative in Delaware. Our remaining nine members, which serve the Virginia mainland, are: BARC Electric Cooperative, Community Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Northern Virginia Electric Cooperative ("NOVEC"), Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative, and Southside Electric Cooperative. Shenandoah Valley Electric Cooperative also serves a small portion of West Virginia. The member distribution cooperatives are not our subsidiaries, but rather our owners. We have no interest in their properties, liabilities, equity, revenues, or margins.

Wholesale Power Contracts

We sell power to our member distribution cooperatives under "all-requirements" wholesale power contracts. Each contract obligates us to sell and deliver to the member distribution cooperative, and obligates the member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions, to the extent that we have the power and facilities available to do so. Each of these wholesale power contracts is effective through 2028 and continues in effect beyond 2028 until either party gives the other at least three years notice of termination. See "—Northern Virginia Electric Cooperative" below for a description of negotiations and proceedings related to the wholesale power contract of one of our members.

There are two principal exceptions to the all-requirements obligations of the parties. First, each Virginia mainland member distribution cooperative may purchase power allocated to it from the Southeastern Power Administration ("SEPA"), which operates hydroelectric facilities in Virginia. The total allocation of power from SEPA to the member distribution cooperatives in 2006 was 76 megawatts ("MW") plus associated energy. This power represented approximately 3.0% of our total member distribution cooperatives' peak capacity requirements and approximately 1.3% of our total member distribution cooperatives' energy requirements. In 2006, the energy received by our member distribution cooperatives from SEPA was comparable to that received in 2005. Second, if pursuant to the Public Utility Regulatory Policies Act ("PURPA") or other laws, a member distribution cooperative is required to purchase electric power from a qualifying facility, the member distribution cooperative must make the required purchases. Any required purchases made by the member distribution cooperative will be at a rate no more than our avoided cost, as established by us. At our option, the member distribution cooperative will sell that power to us at a price no more than that rate. The member distribution cooperative may appoint us to act as its agent in all dealings with the owner of any of these qualifying facilities. Purchases of power generated by qualifying facilities constituted less than 1.0% of our member distribution cooperatives' capacity and energy requirements in 2006.

Each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract in accordance with our formulary rate. The formulary rate, which has been filed with and accepted by the Federal Energy Regulatory Commission ("FERC"), is designed to recover our total cost of service and create a firm equity base. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formulary Rate" in Item 7. More specifically, the formulary rate is intended to meet all of our costs, expenses and financial obligations associated with our ownership, operation, maintenance, repair, replacement, improvement, modification, retirement and decommissioning of our generating plants, transmission system or related facilities, as well as all of our costs, expenses and financial obligations relating to the acquisition and sale of power or related services that we provide to our member distribution cooperatives under the wholesale power contracts, including:

- payments of principal and premium, if any, and interest on all indebtedness issued by us (other than payments resulting from the acceleration of the maturity of the indebtedness);

- the cost of any power purchased by us for resale by us under the wholesale power contracts and the costs of transmission, scheduling, dispatching and controlling services for delivery of electric power;

- any additional cost or expense, imposed or permitted by any regulatory agency or which is paid or incurred by us relating to our generating plants, transmission system or related facilities or relating to the services we provide to our member distribution cooperatives that is not otherwise included in any of the costs specified in the wholesale power contracts;

- all amounts we are required to pay under any contract to which we are a party;

- additional amounts required to meet the requirement of any rate covenant with respect to coverage of principal and interest on our indebtedness contained in any indenture or contract with holders of our indebtedness; and

- any additional amounts which our board of directors deems advisable in the marketing of our indebtedness.

The rates established under the wholesale power contracts are designed to enable us to comply with financing, regulatory and governmental requirements, which apply to us from time to time.

We may revise our budget at any time to the extent that our current budget does not accurately reflect our demand (or capacity)-related costs and expenses or estimates of our demand sales of power. Increases or decreases in our budget automatically amend the demand component of our formulary rate. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formulary Rate" in Item 7 for a description of capacity-related costs and the demand component of our formulary rate. Also, the wholesale power contracts permit us to adjust the amounts to be collected from the member distribution cooperatives to equal our actual demand costs. We make these adjustments under our Margin Stabilization Plan. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Margin Stabilization Plan" in Item 7. These adjustments are treated as due, owed, incurred and accrued for the year to which the increase or decrease relates. The member distribution cooperatives pay or receive any amounts owed to or by us as a result of this adjustment in the following year. If at any time our board of directors determines that the formula does not meet all of our costs and expenses, it may adopt a new formula to meet those costs and expenses, subject to any necessary regulatory review and approval.

During the term of each wholesale power contract, each member distribution cooperative will not, without obtaining our written consent, take or permit to be taken any steps for reorganization or dissolution, consolidation with or merger into any corporation, or the sale, lease or transfer of all or a substantial portion of its assets. We will not, however, unreasonably withhold our consent to any reorganization, dissolution, consolidation, merger or sale, lease or transfer of assets. In addition, we will not withhold or condition our consent if the transaction would not (1) increase rates to our other member distribution cooperatives, (2) impair our ability to repay our indebtedness or any other obligation, or (3) affect our system performance in any material way. Despite these restrictions, a member distribution cooperative may reorganize or dissolve, consolidate with or merge into any corporation, or sell, lease or transfer a substantial portion of its assets without our consent if it:

- pays the portion of our indebtedness or other obligations as we determine, and

- complies with reasonable terms and conditions that we may require to eliminate any adverse effects on the rates of our other member distribution cooperatives, or to provide assurance that we will have the ability to repay our indebtedness and abide by our other obligations.

Possible Changes to Power Supply Arrangements with Member Distribution Cooperatives

We strive to supply our member distribution cooperatives' power requirements in an efficient and cost effective manner. We consistently explore new ways to serve our member distribution cooperatives better and respond to the challenges we face. These efforts have taken several forms in recent years. In 2004, we developed a plan to reorganize our ownership and power supply arrangements with our members. In addition, we have evaluated possible modifications to our wholesale power contracts with our member distribution cooperatives to address the desire of some of our member distribution cooperatives for additional flexibility in meeting their power requirements. We also have attempted to resolve outstanding issues with our largest member distribution cooperative, NOVEC, in proceedings relating to the potential reorganization and in discussions regarding possible modifications to our wholesale power contracts.

New Dominion

On July 26, 2004, we entered into a reorganization agreement with our twelve member distribution cooperatives, TEC and a newly formed taxable power supply cooperative, New Dominion Energy Cooperative ("New Dominion"). The purpose of New Dominion is to provide us with additional flexibility to finance future capital expenditures and eliminate some existing operational constraints.

Structurally, the reorganization contemplated by the reorganization agreement would result in all of our member distribution cooperatives exchanging their membership interests in ODEC for a membership interest in New Dominion. All of their equity in ODEC would be transferred to New Dominion in return for an equal amount of equity in New Dominion. As a result, New Dominion would become our sole member.

As part of the reorganization, the reorganization agreement requires that New Dominion enter into a take-or-pay power sales contract with us, pursuant to which New Dominion would agree to purchase and receive 100% of the output and services of our power supply resources and to pay 100% of our costs, including amounts sufficient for us to meet the rate covenant under our Indenture of Mortgage and Deed of Trust, dated as of May 1, 1992, with Crestar Bank (predecessor to SunTrust Bank), as trustee (the "Indenture"). Payments required under this contract would not be excused by any event, including our inability or failure to perform. The reorganization agreement further provides that the wholesale power contracts we have with our member distribution cooperatives would be assigned to and assumed by New Dominion. TEC would withdraw as a member in conjunction with the completion of the reorganization and our power sales relationship with TEC also would be terminated at that time.

The reorganization agreement includes several provisions intended to protect our credit profile. We would not transfer our ownership of any of our tangible assets, including our interest in any of our generation facilities, in connection with the reorganization. We would continue to be responsible for all of our existing indebtedness and the reorganization agreement would require New Dominion to guarantee all of our outstanding obligations under our Indenture at the time of the consummation of the reorganization.

The formation of New Dominion and the consummation of the reorganization will have almost no impact on our consolidated financial statements. We currently do not anticipate transferring ownership of any of our assets as part of the reorganization, with one exception. We will transfer to New Dominion, at the direction of our members, any prepayments for electric service held by us as of the reorganization date. These prepayments totaled approximately $44.2 million at December 31, 2006. As described above, we also will continue to be responsible for all our existing indebtedness following the reorganization. The amount of our members' equity will remain unchanged although the number of members we have will be reduced from thirteen to one.

The only change in our liquidity immediately following the reorganization will be the entry into a mutual credit agreement with New Dominion. The mutual credit agreement will permit either ODEC or New Dominion to request from the other an extension of credit in the form of loans, guarantees, or other credit support. This mutual credit agreement will not be a committed credit facility and neither ODEC nor New Dominion will be required to extend credit to the other thereunder.

If consummated, we anticipate that following the reorganization New Dominion would conduct physical and financial power and gas procurement activities and purchase, in the markets, the power needed to supply our member distribution cooperatives over and above that obtained from us. New Dominion would not engage in speculative marketing or trading activities. We would expect to continue to perform all of our other current operations, including our obligations to operate and maintain our generating facilities. Future generating resources, including purchased power agreements, could be owned by either New Dominion or ODEC, depending upon our analysis of the advantages and disadvantages at the time the resources were acquired. New Dominion would be a taxable cooperative; however, no change would occur in our status as an organization exempt from federal income tax a result of the reorganization. We would continue to be regulated by federal or state governmental authorities in the same manner as we currently are, and we expect that New Dominion would be regulated in a similar manner.

Following the reorganization, both our and New Dominion's board of directors would consist of two representatives of each of our member distribution cooperatives. No changes in our management personnel are contemplated as a result of the reorganization. We would supply all administrative and management services required by New Dominion.

Several conditions must be satisfied before the reorganization will occur, including conditions relating to obtaining all necessary regulatory approvals. NOVEC has intervened in proceedings with FERC relating to approvals required for the consummation of the reorganization. See "Legal Proceedings—FERC Proceedings Relating to Potential Reorganization" in Item 3. Because several of these conditions are beyond our control, we cannot determine when or if the reorganization will occur. Even if all other conditions to the reorganization were satisfied, we would have the right to terminate the reorganization agreement because the conditions to closing were not satisfied prior to a specified date in the reorganization agreement. We currently anticipate, however, that we and our member distribution cooperatives will continue to pursue satisfaction of the conditions to the reorganization.

Possible Extensions and Modifications of Wholesale Power Contracts

Over the past several years, we have evaluated the potential of providing our member distribution cooperatives with greater flexibility in their power supply options in the future. In particular, we have had discussions with NOVEC about changing the nature of its wholesale power contract with us from an all-requirements contract to a partial-requirements contract. We have always approached discussions regarding our wholesale power contracts from the perspective that we would never amend or modify the wholesale power contracts in any way that could adversely affect our financial condition or that of any of our member distribution cooperatives. Similarly, no member distribution cooperative, including NOVEC, has ever sought to be relieved of its obligations relating to our existing generating facilities, including debt service and other costs related or allocable to these facilities.

In February 2007, our member distribution cooperatives other than NOVEC agreed on a framework for the potential extension and modification of their wholesale power contracts. The framework provides that these member distribution cooperatives would extend their contracts for a term that would end approximately 45 years following the date of the effectiveness of the modifications. The framework further provides that the wholesale power contracts would be modified to permit – but not obligate – these member distribution cooperatives to purchase the greater of five percent of their power requirements or five megawatts from other suppliers. These member distribution cooperatives also would be permitted to purchase power from other suppliers in limited circumstances following approval by our board of directors. This framework was agreed upon in principle but is subject to satisfactory resolution of several other matters related to the modifications, including the implementation of amendments to our bylaws to require a supermajority approval of our board of directions before we take action in some circumstances. The possible extensions and modifications of the wholesale power contracts of these member distribution cooperatives are not definitive and any final agreement relating to these matters would be subject to approvals by our board of directors and the boards of directors of the applicable member distribution cooperatives, among others.

NOVEC

Although we have discussed potential changes to its wholesale power contract for several years, NOVEC has not agreed with our other member distribution cooperatives regarding this framework for the potential extension and modification of our wholesale power contract with it. The entry into modified wholesale power contracts with our other member distribution cooperatives would not affect our current wholesale power contract with NOVEC. NOVEC's wholesale power contract would continue in effect in accordance with its current terms and conditions described above.

In 2006, NOVEC filed an action with FERC to reform its wholesale power contract. For some time prior to the filing, NOVEC had made known that it might bring such an action before FERC or the Virginia State Corporation Commission ("VSCC"). FERC denied NOVEC's 2006 complaint and its subsequent request for a rehearing. NOVEC has appealed these orders. See "Legal Proceedings — Northern Virginia Electric Cooperative" in Item 3 for a discussion of these proceedings.

While we cannot predict the ultimate resolution of these proceedings, we do anticipate that we will engage in discussions with NOVEC about the possible termination of its wholesale power contract and its withdrawal as a member of Old Dominion. As in the case of any modification of the wholesale power contracts, we will not consider any termination of the wholesale power contract or take any other action in connection with the resolution of our issues with NOVEC that we believe in any way could adversely affect our financial condition or that of our other member distribution cooperatives.

TEC

TEC was formed for the primary purpose of purchasing from us, to sell in the market, energy that is not needed to meet the actual needs of our member distribution cooperatives, acquiring natural gas and forward purchase contracts to hedge the price of natural gas to supply our combustion turbine facilities, and to take advantage of other power-related trading opportunities in the market which will help lower our member distribution cooperatives' costs. TEC does not engage in speculative trading.

TEC is owned by our member distribution cooperatives, and currently is our only Class B member. As a member, TEC is entitled to receive patronage capital distributions from us based on our allocation of margins to Class B members and the amount of its business with us. We are continuing to evaluate the potential reorganization of our relationships with our members, including TEC. See "—New Dominion" above.

We have a power sales contract with TEC, under which TEC purchases power from us that we do not need to meet the actual needs of our member distribution cooperatives for resale to the market and sells this power to the market under market-based rate authority granted by FERC. To fully participate in power-related markets, TEC must maintain credit support sufficient to meet delivery and payment obligations associated with its power trades. To assist TEC in maintaining this credit support, we have agreed to guarantee up to a maximum of $60.0 million of TEC's delivery and payment obligations associated with its power trades. As of December 31, 2006, we had issued guarantees for up to $11.0 million of TEC's obligations and TEC has liabilities of $0.2 million to vendors related to these guarantees.

In 2006, TEC purchased from us, and subsequently sold to the market, 585,887 megawatt-hours ("MWh") of energy. In 2006, we purchased from TEC $43.4 million of natural gas to fuel our combustion turbine facilities. We charged TEC $12,000 for administrative services we performed for TEC in 2006.

In accordance with Financial Accounting Standards Board Interpretation No. 46R, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51" ("FIN 46"), TEC is considered a variable interest entity for which we are the primary beneficiary. We became the primary beneficiary of TEC in 2001. We first consolidated TEC's financial position as of December 31, 2004, and beginning January 1, 2005, TEC's operations were also consolidated as a result of the adoption of FIN 46. For financial reporting purposes, we have eliminated all intercompany balances and transactions in consolidation. The assets and liabilities and non-controlling interest of TEC are recorded at carrying value and the net assets consolidated were $11.0 million and $25.1 million at December 31, 2006, and December 31, 2005, respectively. The decrease in the carrying value of the net assets consolidated is due to the decrease in the number of TEC's natural gas futures contracts held by TEC, and the fair value of these contracts.

Members' Service Territories and Customers

Historically, our member distribution cooperatives have had the exclusive right to provide electric service to customers within their exclusive service territories certified by their respective state public service commissions. The member distribution cooperatives, like other incumbent utilities, then charged their customers a bundled rate for electric service, which included charges for power, transmission services, and distribution (including metering and billing) services.

Virginia, Delaware, and Maryland each grant retail customers the right to choose their power supplier. The laws of each state maintain the exclusive right of the incumbent electric utilities, including our member distribution cooperatives, to continue to provide transmission and distribution services and, at least initially, to be the default providers of power to their customers in their respective service territories. See "—Regulation—Competition" below.

The territories served by our member distribution cooperatives cover large portions of Virginia, Delaware, and Maryland. One of our member distribution cooperatives also serves a small portion of West Virginia. These service territories range from the suburban metropolitan Washington, D.C. area in northern Virginia, to the Atlantic shore of Virginia, Delaware, and Maryland, to the Appalachian Mountains and the North Carolina border. The service territories of member distribution cooperatives serving the high growth, increasingly suburban area between Washington, D.C. and Richmond, Virginia, account for approximately half of our capacity requirements. While our member distribution cooperatives do not serve any major cities, several portions of their service territories are in close proximity to urban areas. These areas continue to experience growth due to the expansion of suburban communities into neighboring rural areas and the continuing development of resort and vacation communities within their service territories.

Our member distribution cooperatives' service territories are diverse and encompass primarily suburban, rural and recreational areas. These territories predominantly reflect historically stable growth in residential capacity and energy requirements both with respect to power sales and number of customers. These customers' requirements for capacity and energy generally are seasonal and increase in winter and summer as home heating and cooling needs increase and then decline in the spring and fall as the weather becomes milder. Our member distribution cooperatives also serve major industries, which include manufacturing, fisheries, agriculture, forestry and wood products, paper, travel, and trade. Additionally, our member distribution cooperatives can expand their service territories through acquisition.

Our member distribution cooperatives' sales of energy in 2006 totaled approximately 10,562,609 MWh. These sales were divided by type as follows:

Customer Class	Percentage of MWh Sales	Percentage of Customers
Residential	65.0%	92.2%
Commercial and industrial	33.8	7.0
Other	1.2	0.8

From 2001 through 2006, our member distribution cooperatives experienced an average annual compound growth rate of approximately 3.5% in the number of customers and an average annual compound growth rate of 3.9% in energy sales measured in MWh.

Revenues from the following member distribution cooperatives equaled or exceeded 10% of our total revenues in 2006:

Member Distribution Cooperatives	Revenues (in millions)	Percentage of Total Revenues
Northern Virginia Electric Cooperative	$ 214.5	28.7 %
Rappahannock Electric Cooperative	163.7	21.9
Delaware Electric Cooperative	80.0	10.7

The member distribution cooperatives' average number of customers per mile of energized line has increased approximately 5.7% since 2001 to approximately 9.5 customers per mile in 2006. System densities of our member distribution cooperatives in 2006 ranged from 6.2 customers per mile in the service territory of BARC Electric Cooperative to 21.1 customers per mile in the service territory of NOVEC. In 2006, the average service density for all distribution electric cooperatives in the United States was approximately 7.0 customers per mile.

POWER SUPPLY RESOURCES

General

We provide power to our members through a combination of our interests in the Clover Power Station ("Clover"), North Anna Nuclear Power Station ("North Anna"), Louisa generating facility ("Louisa"), Marsh Run generating facility ("Marsh Run"), Rock Springs generating facility ("Rock Springs"), distributed generation facilities, long-term and short-term physically-delivered forward power purchase contracts and spot purchases of power in the open market. Our power supply resources for the past three years have been as follows:

	Year Ended December 31,					
	2006		2005		2004	
Generated:			(in MWh and percentages)			
Clover	3,470,018	27.4 %	3,190,796	24.9 %	3,342,530	29.2 %
North Anna	1,752,349	13.8	1,784,512	14.0	1,718,545	15.0
Louisa	221,400	1.7	200,535	1.6	212,087	1.9
Marsh Run	232,330	1.8	243,864	1.9	25,761	0.2
Rock Springs	55,692	0.5	119,387	0.9	125,244	1.1
Distributed generation	719	-	2,312	-	354	-
Total Generated	5,732,508	45.2	5,541,406	43.3	5,424,521	47.4
Purchased:						
Total Purchased	6,956,454	54.8	7,260,938	56.7	6,005,984	52.6
Total Available Energy	12,688,962	100.0 %	12,802,344	100.0 %	11,430,505	100.0 %

Typically, our member distribution cooperatives' peak demand for energy occurs in the summer. This peak is due in large part to the summer air conditioning requirements of the member distribution cooperatives' customers, which reflects the large residential component of our total capacity requirements. In 2006, the peak demand for the member distribution cooperatives' customers occurred in August.

Clover and North Anna satisfied approximately 26.3% of our capacity requirements and 41.2% of our energy requirements in 2006. Louisa, Marsh Run and Rock Springs provided 18.8%, 19.2%, and 12.9% of our 2006 capacity requirements, respectively, and 1.7%, 1.8%, and 0.5%, respectively, of our 2006 energy requirements. In 2006, we obtained the remainder of our capacity and energy requirements from numerous suppliers under various long-term and short-term physically-delivered forward power purchase contracts and spot market purchases. Most of our long-term power purchase contracts will expire by the end of 2010. See "—Power Purchase Contracts" below.

Power Supply Resources

Generating Facilities

We have ownership interests in five electric generating facilities plus distributed generation facilities. For a description of these facilities see "Properties" in Item 2. In 2006, these facilities provided 45.2% of our energy requirements.

Power Purchase Contracts

In 2006, we purchased approximately 54.8% of our total energy requirements. These energy requirements were provided principally by neighboring utilities and power marketers through long-term and short-term physically-delivered power purchase contracts and purchases of energy in the spot markets.

Our most significant long-term power purchase arrangements are with Virginia Electric & Power Company ("Virginia Power"), the operator and co-owner of Clover and North Anna. We have an agreement with Virginia Power which grants us the right, but not the obligation, to purchase energy at a price determined by reference to a specified natural gas index (the Operating and Power Sales Agreement or "OPSA"). In addition, we have other contractual arrangements with Virginia Power which permit us to purchase reserve capacity and energy. We intend to purchase our reserve capacity requirements for Clover and North Anna from Virginia Power under these arrangements until either the date on which all facilities at North Anna have been retired or decommissioned, or the date we have no interest in North Anna, whichever is earlier. The purchase price we pay for any reserve energy purchased under these arrangements equals the natural gas-indexed price we pay for intermediate energy under our other agreements with Virginia Power. In addition to Virginia Power, we have other power purchase agreements with Mid-Atlantic utilities, which provide a small portion of our capacity and energy requirements.

The remainder of our energy requirements is provided by the market. We purchase significant amounts of power in the market through long-term and short-term physically-delivered forward power purchase contracts. We also purchase power in the spot market. This approach to meeting our member distribution cooperatives' energy requirements is not without risks. See "Risk Factors" in Item 1A. below. To mitigate these risks, we attempt to match our energy purchases with our energy needs to reduce our spot market purchases of energy. Additionally, we utilize policies and procedures to manage the risks in the changing business environment. These procedures, developed in cooperation with ACES Power Marketing LLC ("APM"), are designed to strike the appropriate balance between minimizing costs and reducing energy cost volatility. See also "Management's Discussion and Analysis of Financial Condition and Results of Operations—Future Issues—Reliance on Market Purchases of Energy" in Item 7.

Transmission

We rely on transmission services provided by PJM Interconnections, LLC ("PJM") to serve our member distribution cooperatives. PJM is a regional transmission organization of transmission facilities serving all of Delaware, Maryland, West Virginia and most of Virginia, as well as other areas outside our member distribution cooperatives' service territories.

We transmit power to our twelve member distribution cooperatives through the transmission systems of PJM – South, PJM – West Region, and PJM – Classic Region. We have agreements with PJM, which provide us with access to transmission facilities under their control as necessary to deliver energy to our member distribution cooperatives. We own a small amount of transmission facilities. See "Properties" in Item 2.

PJM continually balances its participants' power requirements with the power resources available to supply those requirements. Based on this evaluation of supply and demand, PJM schedules available resources in a manner intended to meet the demand for power in the most reliable and cost-effective manner. When available resources cannot be dispatched due to transmission constraints, more expensive generating facilities must be dispatched to meet the requested power requirements. PJM participants whose power requirements cause the redispatch are obligated to pay the additional costs to dispatch the more expensive generating facilities. These additional costs are commonly referred to as congestion costs. PJM operates the transmission system in a manner intended to support a competitive generation marketplace. PJM has proposed additional transmission upgrades and these efforts may reduce our congestion costs in the future. Our net congestion costs for 2006 were approximately $13.4 million.

Fuel Supply

Nuclear

Virginia Power, as operating agent, has the sole authority and responsibility to procure nuclear fuel for North Anna. Virginia Power advises they use primarily long-term contracts to support North Anna's nuclear fuel requirements and that worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices which are dependent upon the market environment. We are not a direct party to any of these procurement contracts, and therefore cannot control their terms or duration. Virginia Power reports that current agreements, inventories, and spot market availability are expected to support North Anna's current and planned fuel supply needs and that additional fuel is purchased as required to attempt to ensure optimum cost and inventory levels.

Coal

Virginia Power, as operating agent, has the sole authority and responsibility to procure sufficient coal for the operation of Clover. Historically, Virginia Power has employed both long-term contracts and spot market purchases to acquire the low sulfur bituminous coal used to fuel the facility. Virginia Power advises us that its procurement policy is to secure the bulk of the coal requirements under long-term contracts, with specific contract target percentages fluctuating, based on prevailing market conditions. We are not a direct party to any of these procurement contracts, and therefore cannot control their terms or duration. As of December 31, 2006, and December 31, 2005, there was a 38.5 day and a 26.5 day supply of coal at Clover, respectively. We anticipate that sufficient supplies of coal will be available in the future at reasonable prices, but market prices and price volatility both may be higher than we currently anticipate. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

Natural Gas

Many electric generating facilities are fueled by natural gas, causing an increase in competition for natural gas capacity. Our three operating combustion turbine facilities are powered by natural gas and are located adjacent to natural gas transmission lines. With assistance from APM, we developed and utilize a natural gas supply strategy for providing natural gas to each of the three combustion turbine facilities. We are responsible for procuring the natural gas to be used by all units at Louisa, Marsh Run and Rock Springs. The strategy includes securing transportation contracts and incorporating the ability to use No. 2 distillate fuel oil as a back up fuel for Louisa and Marsh Run, as needed, to minimize transportation costs. We have identified our primary natural gas suppliers and have negotiated the contracts needed for procurement of physical natural gas. We have put in place strategies and mechanisms to financially hedge our natural gas needs. We presently anticipate that sufficient supplies of natural gas will be available in the future at reasonable prices making the operation of the combustion turbine facilities economical or when their operation is required by PJM for system reliability purposes, but significant price volatility may occur. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

REGULATION

General

We are subject to regulation by FERC and to a limited extent, state public service commissions. Some of our operations are also subject to regulation by the Virginia Department of Environmental Quality ("DEQ"), the Department of Energy ("DOE"), the Nuclear Regulatory Commission ("NRC"), and other federal, state, and local authorities. Compliance with future laws or regulations may increase our operating and capital costs by requiring, among other things, changes in the design or operation of our generating facilities.

Rates

FERC regulates our rates for transmission services and wholesale sales of power in interstate commerce. We establish our rates for power furnished to our member distribution cooperatives pursuant to our formulary rate, which has been accepted by FERC. The formulary rate is intended to permit us to collect revenues, which, together with revenues from all other sources, are equal to all of our costs and expenses, plus an additional amount up to 20% of our total interest charges, plus additional equity contributions as approved by our board of directors. The formula has three main components: a demand rate, a base energy rate, and a fuel factor adjustment rate. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results – Formulary Rate" in Item 7.

FERC may review our rates upon its own initiative or upon complaint and order a reduction of any rates determined to be unjust, unreasonable, or otherwise unlawful and order a refund for amounts collected during such proceedings in excess of the just, reasonable, and lawful rates. Our charges to TEC are established under our market-based sales tariff filed with FERC.

Because our rates and services are regulated by FERC, the VSCC, the Delaware Public Service Commission ("Delaware PSC"), and the Maryland Public Service Commission ("Maryland PSC") do not have jurisdiction over our rates and services. The state commissions, however, do oversee the siting of our utility facilities in their respective jurisdictions. They also regulate the rates and services offered by our Virginia and Maryland member distribution cooperatives. Effective August 2006, one of our member distribution cooperatives, Delaware Electric Cooperative, is no longer regulated by the Delaware PSC.

Other FERC Regulation

In addition to its jurisdiction over rates, FERC regulates the issuance of securities and assumption of liabilities by us, as well as mergers, consolidations, the acquisition of securities of other utilities, and the disposition of property other than generating facilities. Under FERC regulations, we are prohibited from selling, leasing, or otherwise disposing of the whole of our facilities subject to FERC jurisdiction (other than generating facilities), or any part of such facilities having a value in excess of $10.0 million without FERC approval.

Competition

Virginia, Delaware and Maryland each have laws unbundling the power component (also known as generation) of electric service to retail customers, while maintaining regulation of transmission and distribution services. All retail customers in Virginia, Delaware and Maryland, including retail customers of our member distribution cooperatives, are currently permitted to purchase power from the registered supplier of their choice. At March 1, 2007, no entity had registered to be an alternative power supplier in any of the service territories of our member distribution cooperatives and, as a result, none of their retail customers have switched to alternative providers. If customers of our member distribution cooperatives choose alternative power suppliers in the future, this could result in a reduction in our revenues and cash flows. If the resulting decrease in our member revenues is significant enough, we could lose our tax-exempt status. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Tax Status" in Item 7.

To address the difference between what an electric utility would have recovered under regulated cost-of-service rates and what that electric utility would have recovered under competitive market rates, sometimes referred to as "stranded costs," and to facilitate the implementation of retail competition, legislation was passed in Virginia, Delaware and Maryland requiring each incumbent utility to cap the rates that it charges its retail customers in its certificated service territory during a specified transition period. The transition periods for our Delaware member distribution cooperative and our Maryland member distribution cooperative expired in 2005. Capped rates extend until December 31, 2010, for our Virginia member distribution cooperatives. These capped rates are unbundled, or itemized, into power, transmission and distribution components and a competitive transition charge. Our member distribution cooperatives located in Virginia have the ability to pass through to their customers, changes in energy costs even while under capped rates. Additionally, they may request one change in their capped rates prior to July 1, 2007, and one additional change between July 1, 2007 and December 31, 2010. Currently, there is legislation pending approval in Virginia that would change the termination of the capped rates from December 31, 2010 to December 31, 2007. Beginning January 1, 2008, this legislation would allow our Virginia member distribution cooperatives to adjust their rates on a cumulative basis by a maximum net increase or decrease of 5% in any three year period without presenting a rate case to the VSCC. This new legislation would not affect our Virginia member distribution cooperatives ability to pass through to their customers, changes in energy costs. This legislation is subject to approval by the Governor of Virginia in early April 2007.

Environmental

We are subject to federal, state, and local laws and regulations and permits designed to protect human health and the environment and regulate the emission, discharge, or release of pollutants into the environment. We believe we are in material compliance with all current requirements of such environmental laws and regulations and permits. As with all electric utilities, the operation of our generating units could, however, be affected by future environmental regulations. Capital expenditures and increased operating costs required to comply with any future regulations could be significant. See "Risk Factors" in Item 1A. below.

Our direct capital expenditures for environmental control facilities at Clover and North Anna, excluding capitalized interest, were immaterial in 2006. Based upon information provided by Virginia Power, we anticipate that beginning in 2011, we will have an increase in our direct capital expenditures for environmental control facilities at Clover. In 2006, we did not have any direct capital expenditures for environmental control facilities at our Louisa, Marsh Run or Rock Springs combustion turbine facilities and there are currently no projected capital expenditures for environmental control facilities in 2007, 2008, or 2009. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Expenditures" in Item 7.

The most important environmental law affecting our operations is the Clean Air Act. The Clean Air Act requires, among other things, that owners and operators of fossil fuel-fired power stations limit emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x"). In addition, regulations have been issued to limit emissions of mercury, and programs are being proposed to limit emissions of carbon dioxide ("CO_2") and other greenhouse gases.

With respect to SO_2, under the Clean Air Act's Acid Rain Program, each of our fossil fuel-fired plants must obtain SO_2 allowances equal to the number of tons of SO_2 they emit into the atmosphere annually. The total number of allowances is capped, and allowances can be traded. As a facility that was built before the Acid Rain Program, Clover receives an annual allocation of SO_2 allowances at no cost based upon its baseline operations. Newer facilities, including Louisa, Marsh Run and Rock Springs, need to obtain allowances, but because they are primarily gas-fired, the number of SO_2 allowances they must obtain are expected to be minimal and will be supplied from excess SO_2 allowances allocated to Clover. On March 10, 2005, the EPA issued the Clean Air Interstate Rule ("CAIR"), requiring significant reductions of SO_2 and NO_x in the eastern United States, including Virginia and Maryland. During its 2006 session, the Virginia General Assembly adopted legislation setting the framework for the implementation of CAIR in Virginia. The DEQ adopted the final CAIR regulation and it is expected to be published in the Virginia Register in the spring. With respect to SO_2, emissions it is expected that Virginia will participate in the federal SO_2 cap and trade program established by CAIR. That program is similar, but is in addition to the Acid Rain Program and would require all of our facilities in Virginia (including Clover) to acquire additional allowances for each ton of SO_2 they emit beginning in 2009, and additional allowances per ton starting in 2015. We are entitled to sufficient SO_2 allowances because of our interest in Clover so that we do not anticipate needing to purchase additional SO_2 allowances for the Louisa, Marsh Run and Rock Springs generating facilities through both phases of CAIR.

Pursuant to the Clean Air Act, both Virginia and Maryland have enacted regulations to reduce the emissions of NO_x by establishing NO_x cap and trade programs similar to the federal SO_2 allowance programs. Both of these programs are being revised to meet the more stringent NO_x emission caps established under CAIR and with respect to the facilities in Virginia, additional NO_x emission reductions mandated by the Virginia General Assembly. Under the current system, Clover is allocated a certain number of NO_x allowances. If Clover, even with use of conventional and advanced pollution control equipment emits more, then additional NO_x emissions allowances will have to be purchased. We have an agreement with Virginia Power to provide us with the option each year to purchase from it the NO_x emissions allowances necessary to compensate for any shortfall between our NO_x emissions allowance requirement for Clover and our portion of the regulatory NO_x emissions allocation for Clover.

Louisa, Marsh Run and Rock Springs will each emit significant amounts of NO_x. In 2006, NO_x allowances were allocated and we anticipate receiving NO_x allowances through 2008. All three sites will be allocated NO_x emission allowances under CAIR. NO_x emission allowances that are not received from the new source set aside pools will be purchased in the market for the operation of all three combustion turbine facilities. We project that we will be able to obtain sufficient quantities of NO_x allowances in the future at commercially reasonable prices, but increased NO_x emissions or increased restrictions could cause the price of allowances to be higher than we expect.

In December 2000, the EPA determined that it was appropriate and necessary to regulate mercury emissions from oil and coal-fired power plants as a hazardous air pollutant under the Clean Air Act. In March 2005, the EPA reversed that earlier decision and instead issued the Clean Air Mercury Rule ("CAMR") which establishes caps for overall mercury emissions that would be implemented in two phases, with the first phase becoming effective in 2010 and the second phase in 2018, and allows the individual states to regulate mercury emissions through a market-based cap and trade program. In response to a request for reconsideration, the EPA confirmed its approach in May 2006. In June 2006, 16 states and several environmental groups filed law suits challenging CAMR and the law suits are currently pending. We cannot predict the outcome of the ongoing challenges of CAMR or what effects any decision may have that would require the EPA to regulate mercury as a hazardous air pollutant. In 2006, the Virginia General Assembly decided to adopt the cap and trade program foreseen in CAMR, subject to certain limitations. If the EPA's decisions are upheld and CAMR is implemented we do not anticipate that any additional measures will be required at Clover due to Clover's existing pollution control requirement which already removes greater than 90% of the mercury.

In addition to traditional air pollutants, the question of climate change has been the focus of much public attention. Several bills have been introduced in Congress to limit emissions of CO_2 and other greenhouse gases believed to contribute to climate change. Also, there are numerous actions at the state and regional level, including the Regional Greenhouse Gas Initiative ("RGGI") established in December 2005 by the governors of seven Northeastern and Mid-Atlantic states. The RGGI provides for a cap and trade system for CO_2 among those states, capping emissions at current levels in 2009, and then reducing emissions 10% by 2019. In 2006, Maryland decided to join the RGGI. Climate change issues are also the subject of several lawsuits, although we were not party to any of those lawsuits. In November 2006, the U.S. Supreme Court heard a case concerning the EPA's authority to regulate CO_2 emissions under the Clear Air Act. The case concerns CO_2 emissions from the transportation sector, but the Court's decision will also influence the regulation of other sectors. We cannot exclude the possibility that future CO_2 emission regulations could have a significant effect on our operations, especially at Clover; however, at this stage we are not able to predict the final form of any such regulation.

The Clean Water Act and applicable state laws regulate water intake structures, discharges of cooling water, storm water run-off and other wastewater discharges at our generating facilities. We are in material compliance with these requirements and with permits that must be obtained with respect to such discharges. Our permits are subject to periodic review and renewal proceedings, and can be made more restrictive over time. Limitations on the thermal discharges in cooling water, or withdrawal of cooling water during low flow conditions, can restrict our operations. During 2006, we experienced no such restrictions; however, such restrictions can arise during drought conditions. Clover has two consent orders with the DEQ. One consent order is to study the impact of withdrawing water to support Clover during low river flow conditions and the other is to relocate one of the landfill discharge pipes from Black Walnut Creek to the Roanoke River. The low flow study has been conducted and the results are being finalized. One of the landfill discharge pipes has been relocated to the Roanoke River.

New legislative and regulatory proposals are frequently proposed on both a federal and state level that would modify the environmental regulatory programs applicable to our facilities. An example is the control of carbon dioxide and other "greenhouse" gases that may contribute to global climate change. With respect to proposed legislation and regulatory proposals that have not yet been formally proposed, we cannot provide meaningful predictions regarding their final form, or their possible effects upon our operations.

We incurred approximately \$5.7 million, \$9.4 million, and \$11.0 million, of expenses, including depreciation, during 2006, 2005, and 2004, respectively, in connection with environmental protection and monitoring activities, such as costs related to the disposal of solid waste, operation of landfills, operation of air emissions reduction equipment, and disposal of hazardous waste material. These expenses were included in fuel expense, operations and maintenance expense, and depreciation, amortization and decommissioning expense. We anticipate expenses to be approximately \$5.0 million in 2007 in connection with environmental protection and monitoring activities, including depreciation.

Nuclear

Under the Nuclear Waste Policy Act, the DOE is required to provide for the permanent disposal of spent nuclear fuel produced by nuclear facilities, such as North Anna, in accordance with contracts executed with the DOE. However, since the DOE did not begin accepting spent fuel in 1998 as specified in its contracts, Virginia Power is providing on-site spent nuclear fuel storage at the North Anna facility site. Virginia Power will continue to safely manage its spent nuclear fuel until the DOE begins accepting the spent nuclear fuel. In January 2004, Virginia Power filed a lawsuit seeking recovery damages for breach of the contract due to the DOE's delay in accepting spent nuclear fuel from North Anna.

ITEM 1A. – RISK FACTORS

RISK FACTORS

The following risk factors and all other information contained in this report should be considered carefully when evaluating Old Dominion. These risk factors could affect our actual results and cause these results to differ materially from those expressed in any forward-looking statements of Old Dominion. Other risks and uncertainties, in addition to those that are described below may also impair our business operations. We consider the risks listed below to be material, but you may view risks differently than we do and we may omit a risk that we consider immaterial but you consider important. An adverse outcome of any of the following risks could materially affect our business or financial condition. These risk factors should be read in conjunction with the other detailed information set forth in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 below, including "Caution Regarding Forward Looking Statements."

We rely substantially on purchases of energy from other power suppliers.

We supply our member distribution cooperatives with all of their power, that is capacity and energy, requirements, with limited exceptions. Our costs to provide this capacity and energy are passed through to our member distribution cooperatives under our wholesale power contracts. We obtain the power to serve their requirements from generating facilities in which we have an interest and purchases of power from other power suppliers.

Historically, our power supply strategy has relied substantially on purchases of energy from other power suppliers. In 2006, we purchased approximately 54.8% of our energy resources. These purchases consisted of a combination of purchases under long-term and short-term physically-delivered forward contracts and purchases of energy in the spot markets. Our reliance on energy purchases may continue well into the future and may increase as our member distribution cooperatives' requirements for power increase. Our reliance on energy purchases also could increase because the operation of our generation facilities is subject to many risks, including the shutdown of our facilities or breakdown or failure of equipment.

Purchasing power helps us mitigate high fixed costs relating to the ownership of generating facilities but exposes us, and consequently our member distribution cooperatives, to significant market price risk because energy prices can fluctuate substantially. When we enter into long-term power purchase contracts or agree to purchase energy at a date in the future, we rely on models based on our judgments and assumptions. These judgements and assumptions relate to factors such as future demand for power and market prices of energy and the price of commodities, such as natural gas used to generate electricity. Our models cannot exactly predict what will actually occur and our results may vary from what our models predict, which may in turn impact our resulting costs to our members. Our models become less reliable the further into the future that the estimates are made. Although we have engaged APM, an energy trading and risk management company, to assist us in developing strategies to meet our power requirements in the most economical manner and we have implemented a hedging strategy to limit our exposure to variability in the market, we still may purchase energy at a price which is higher than our member distribution cooperatives' competitors' costs of generating energy or future market prices of energy. For further discussion of our market price risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk."

Changes in fuel and purchased power costs could increase our generating costs.

We are subject to changes in fuel costs, which could increase the cost of generating power and thus increase the cost to our member distribution cooperatives. The market prices for fuel may fluctuate over relatively short periods of time. Factors that could influence fuel costs are:

- Weather;
- Supply and demand;
- The availability of competitively priced alternative energy sources;
- The transportation of fuels;
- Price competition among fuels used to produce electricity, including natural gas, coal and crude oil;
- Energy transmission or natural gas transportation capacity constraints;
- Federal, state and local energy and environmental regulation and legislation; and
- Natural disasters, war, terrorism, and other catastrophic events.

Adverse changes in our credit ratings could negatively impact our ability to access capital and may require us to provide credit support for some of our obligations.

Changes in our credit ratings could affect our ability to access capital. Standard & Poor's Ratings Services ("S&P"), Moody's Investors Service ("Moody's"), and Fitch Inc., currently rate our outstanding obligations issued under the Indenture at "A", "A3", and "A", respectively. If these agencies were to downgrade our ratings, particularly below investment grade, we may be required to pay higher interest rates on financings, which we may decide to undertake in the future, and our potential pool of investors and funding sources could decrease. In addition, in limited circumstances, we have obligations to provide credit support if our obligations issued under the Indenture are rated below specified thresholds by S&P and Moody's. These circumstances relate to lease and leaseback of our undivided interest in Clover Unit 1 and some of our purchases of power in the market. See also "Management's Discussion and Analysis of Financial Condition and Results of Operations—Significant Contingent Obligations" in Item 7.

To the extent that we would have to provide additional credit support as a result of a downgrade in our credit ratings, our ability to access additional credit may be limited and our liquidity, including our ability to service our outstanding indebtedness, may be materially impaired.

We are subject to risks associated with owning an interest in a nuclear generation facility.

We have an 11.6% undivided ownership interest in North Anna which provided approximately 13.8% of our energy requirements in 2006. Ownership of an interest in a nuclear generating facility involves risks, including:

- potential liabilities relating to harmful effects on the environment and human health resulting from the operation of the facility and the storage, handling and disposal of radioactive materials;

- significant capital expenditures relating to maintenance, operation and repair of the facility, including repairs required by the NRC;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with operation of the facility; and
- uncertainties regarding the technological and financial aspects of decommissioning a nuclear plant at the end of its licensed life.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of North Anna. If the facility is not in compliance, the NRC may impose fines or shut down one or both units until compliance is achieved or both depending upon its assessment of the situation. Revised safety requirements issued by the NRC have, in the past, necessitated substantial capital expenditures at other nuclear generating facilities. In addition, although we have no reason to anticipate a serious nuclear incident at North Anna, if an incident did occur, it could have a material but presently undeterminable adverse effect on our operations or financial condition. Further, any unexpected shut down at North Anna as a result of regulatory non-compliance or unexpected maintenance will require us to purchase replacement energy. We can buy this replacement power either from Virginia Power under the OPSA or the market. See "Power Supply Resources—Power Purchase Contracts."

Environmental regulation may limit our operations or increase our costs or both.

We are required to comply with numerous federal, state and local laws and regulations relating to the protection of the environment. While we believe that we have obtained all material environmental-related approvals currently required to own and operate our facilities or that these approvals have been applied for and will be issued in a timely manner, we may incur significant additional costs because of compliance with these requirements. Failure to comply with environmental laws and regulations could have a material effect on us, including potential civil or criminal liability and the imposition of fines or expenditures of funds to bring our facilities into compliance. Delay in obtaining, or failure to obtain and maintain in effect any environmental approvals, or the delay or failure to satisfy any applicable environmental regulatory requirements related to the operation of our existing facilities or the sale of energy from these facilities could result in significant additional cost to us.

Our financial condition is largely dependent upon our members.

Our financial condition is largely dependent upon our member distribution cooperatives satisfying their obligations under the "all-requirements" wholesale power contract that each has executed with us. The wholesale power contracts require our member distribution cooperatives pay us for power furnished to them in accordance with our FERC formulary rate, which is designed to permit us to recover our total cost of service and create a firm equity base. Our board of directors, which is composed of representatives of our members, can approve changes in the rates we charge to our member distribution cooperatives without seeking FERC approval with limited exceptions. In 2006, 61.3% of our revenues were received from our three largest members, NOVEC, Rappahannock Electric Cooperative and Delaware Electric Cooperative.

Since January 2005, we have been involved in litigation with NOVEC, our largest member, regarding our potential reorganization and NOVEC's desire to change the nature of its wholesale power contract to a partial-requirements contract. While we cannot predict the ultimate resolution of these matters, we will not amend or modify our wholesale power contracts in any way that could adversely affect our financial condition or that of our member distribution cooperatives.

The use of hedging instruments could impact our liquidity.

We use hedging instruments, including forwards, futures, financial transmission rights, and options, to manage our power market price risks. These hedging instruments generally include collateral requirements that require us to deposit funds or post letters of credit with counterparties when a counterparty's credit exposure to us is in excess of agreed upon credit limits. When commodity prices decrease to levels below the levels where we have hedged future costs, we may be required to use a material portion of our cash or liquidity facilities to cover these collateral requirements. See also "Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Price Risk" in Item 7A.

Counterparties under power purchase arrangements may fail to perform their obligations to us.

Because we rely substantially on the purchase of energy from other power suppliers, we are exposed to the risk that counterparties will default in performance of their obligations to us. While we utilize APM to assist us in analyzing default risks of counterparties and other credit issues related to these purchases, and we may require our counterparties to post collateral with us, defaults may still occur. Defaults may take the form of failure to physically deliver the purchased energy. If this occurs, we may be forced to enter into alternative contractual arrangements or purchase energy in the forward, short-term or spot markets at then-current market prices that may exceed the prices previously agreed upon with the defaulting counterparty.

Our member distribution cooperatives are subject to market competition.

Virginia, Delaware and Maryland each permit our member distribution cooperatives' customers to purchase electricity from an alternate supplier while our member distribution cooperatives continue to provide distribution services to all consumers of electricity located in their certificated service territories. Substantially all of our member distribution cooperatives' customers are free to choose an alternate power supplier; however, to date, no customer of our member distribution cooperatives has selected an alternate supplier of power. The competitive retail market has been slow to develop and therefore it is difficult to predict the pace at which a competitive environment will evolve and the impact on us or our member distribution cooperatives. See "Business—Regulation—Competition" in Item 1 above.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

Our principal properties consist of our interest in five electric generating facilities, additional distributed generation facilities across our member distribution cooperatives' service territories and a small amount of transmission facilities. All of our physical properties are subject to the lien of our Indenture. See "Restated Indenture" below. Our generating facilities consist of the following:

Name of Facility	Ownership Interest	Location	Primary Fuel	Commercial Operation Date	Net Capacity Entitlement[3]
Clover	50.0%[1]	Halifax County, Virginia	Coal	Unit 1 – 10/1995	215 MW
				Unit 2 – 03/1996	215 MW
					430 MW
North Anna	11.6%	Louisa County, Virginia	Nuclear	Unit 1 – 06/1978 [4]	107 MW
				Unit 2 – 12/1980 [4]	107 MW
					214 MW
Louisa	100.0%	Louisa County, Virginia	Natural Gas	Unit 1 – 06/2003	84 MW
				Unit 2 – 06/2003	84 MW
				Unit 3 – 06/2003	84 MW
				Unit 4 – 06/2003	84 MW
				Unit 5 – 06/2003	168 MW
					504 MW
Marsh Run	100.0%	Fauquier County, Virginia	Natural Gas	Unit 1 – 09/2004	168 MW
				Unit 2 – 09/2004	168 MW
				Unit 3 – 09/2004	168 MW
					504 MW
Rock Springs	50.0%[2]	Cecil County, Maryland	Natural Gas	Unit 1 – 06/2003	168 MW
				Unit 2 – 06/2003	168 MW
					336 MW
Distributed generation	100.0%	Multiple	Diesel	10 units – 07/2002	20 MW
				Total	2,008 MW

(1) Our interest in Clover is subject to long-term leases. See "Clover" below.
(2) We own 100% of two units, each with a net capacity rating of 168 MW, and 50% of the common facilities for the facility. See "Combustion Turbine Facilities—Rock Springs" below.
(3) Represents an approximation of our entitlement to the maximum dependable capacity, which does not represent actual usage.
(4) We purchased our 11.6% undivided ownership interest in North Anna in December 1983.

Clover

Virginia Power, as the co-owner of Clover, is responsible for operating Clover and procuring and arranging for the transportation of the fuel required to operate Clover. See "Power Supply Resources—Fuel Supply—Coal" in Item 1. We are responsible for and must fund half of all additions and operating costs associated with Clover, as well as half of Virginia Power's administrative and general expenses for Clover. Under the terms of the Clover operating agreement, Old Dominion and Virginia Power each take half of the power produced by Clover.

Lease of Clover Unit 1

In March 1996, we entered into a lease with an owner trust for the benefit of an investor in which we leased our interest in Clover Unit 1 and related common facilities, subject to the lien of the Indenture, for a term extendable by the owner trust up to the full productive life of Clover Unit 1, and simultaneously entered into an approximately 21.8 year lease of the interest back to us. If the lien of the Indenture is ever released, the interest of the owner trust in Clover Unit 1 would no longer be subject and subordinate to the lien of the Indenture in the future. See "Restated Indenture" below. We have provided for substantially all of our periodic basic rent payments under the lease by investing in obligations issued or insured by entities, the claims paying ability or senior debt obligations of which are rated "AAA" by S&P and "Aaa" by Moody's. The lease to us contains events of default, which, if they occur, could result in termination of the lease, and, consequently, our loss of possession and right to the output of Clover Unit 1.

At the end of the term of the leaseback, we have three options: (1) retain possession of the interest in the unit by paying a fixed purchase price to the owner trust, (2) return possession of the interest to the owner trust and arrange for an acceptable third party to enter into a power purchase agreement with the owner trust, or (3) return possession of the interest and pay a termination amount to the owner trust. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Off-Balance Sheet Arrangements—Clover Leases" in Item 7 for a discussion of our obligations at the end of the term of the leaseback of Clover Unit 1 and sources of funding for these obligations.

Lease of Clover Unit 2

In July 1996, we entered into another lease subject to the lien of the Indenture with an owner trust for the benefit of a different investor of our interest in Clover Unit 2 and related common facilities for a term extendable by the owner trust up to the full productive life of Clover Unit 2. We simultaneously entered into an approximately 23.4 year lease back of the interest. If the lien of the Indenture is ever released , the interest of the owner trust in Clover Unit 2 would no longer be subject and subordinate to the lien of the Indenture in the future. See "Restated Indenture" below. We have provided for all of our periodic basic rent payments under the lease by investing in obligations issued or insured by entities, the claims paying ability or senior debt obligations of which are rated "AAA" by S&P and "Aaa" by Moody's. As with the Clover Unit 1 lease, the leaseback of Clover Unit 2 contains events of default, which could result in termination of the lease and loss of possession and right to the output of the unit.

In connection with this lease, we granted a subordinated lien and security interest in Clover Unit 2 to secure our obligations under the lease and our reimbursement obligation to an insurer for its payments under a surety bond securing some of our payment obligations under the lease. This subordinated lien and security interest will be required to be released prior to the date of the release of the lien of the Indenture in connection with its amendment and restatement unless the holders of obligations issued under the Indenture are equally and ratably secured with respect to the assets subject to the lease. After that date, the interest of the owner trust would no longer be subject and subordinate to the lien of the Indenture. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Future Issues—Restated Indenture" in Item 7 for a discussion of the possible amendment and restatement of the Indenture.

At the end of the term of the leaseback, we may either (1) retain possession of the interest in the unit by paying a fixed purchase price to the owner trust, or (2) return possession of the interest to the owner trust and arrange for an acceptable third party to enter into a power purchase agreement with the owner trust. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Off-Balance Sheet Arrangements—Clover Leases" in Item 7 for a discussion of our obligations at the end of the term of the leaseback of Clover Unit 2 and sources of funding for these obligations.

North Anna

Virginia Power, as the co-owner of North Anna, is responsible for operating North Anna. Virginia Power also has the authority and responsibility to procure nuclear fuel for North Anna. See "Fuel Supply—Nuclear" in Item 1. We are entitled to 11.6% of the power generated by North Anna. Additionally, we are responsible for and must fund 11.6% of all post-acquisition date additions and operating costs associated with North Anna, as well as a pro-rata portion of Virginia Power's administrative and general expenses directly attributable to North Anna. We are obligated to fund these items. In addition, we separately fund our pro-rata portion of the decommissioning costs of North Anna. Old Dominion and Virginia Power also bear pro-rata any liability arising from ownership of North Anna, except for liabilities resulting from the gross negligence of the other.

Combustion Turbine Facilities

Louisa

We undertook responsibility for the operation and maintenance of the Louisa facility beginning in 2006. We supply all services, goods and materials required to operate the facility, including arranging for the transportation and supply of the natural gas and No. 2 distillate fuel oil required by the facility.

Marsh Run

We also operate and maintain the Marsh Run facility. We supply all services, goods and materials required to operate the facility, including arrangement for the transportation and supply of the natural gas and No. 2 distillate fuel oil required by the facility.

Rock Springs

The Rock Springs facility was developed together with another participant, CED Rock Springs, LLC ("ConEd"). ODEC and ConEd each individually own two units (a total of 336 MWs each) and 50% of the common facilities. Additionally, ODEC and ConEd each individually dispatch their respective units as it determines to be necessary and prudent. The facility is currently permitted to allow two additional 168 MW combustion turbines to be installed at the site for a total site capacity of 1,008 MW.

The Rock Springs facility is operated and maintained by CED Operating Co., LLP, an affiliate of ConEd, pursuant to a service agreement under which CED Operating Co., LLP, supplies all services, goods and materials, other than natural gas, required to operate the facility. We are responsible for all costs associated with the development, construction, additions and operating costs and administrative and general expenses relating to our two units and the proportional share of the costs relating to the common facilities for Rock Springs.

We arrange for the transportation of the natural gas required by the operator for all units at Rock Springs and arrange for the supply of natural gas to our units only.

Distributed Generation Facilities

We have distributed generation facilities in our member distribution cooperatives' service territory primarily to enhance our system's reliability. Four diesel generators service our member distributions cooperatives' in the Virginia mainland territory and six diesel generators service our member distribution cooperatives' in the Delmarva Peninsula territory.

Transmission

We own two 1,100 foot 500 kilovolt ("kV") transmission lines and a 500 kV substation at the Rock Springs site jointly with ConEd. As a transmission owner in PJM, we have relinquished control of these transmission facilities to PJM and contracted with third parties to operate and maintain the transmission facilities.

Restated Indenture

In 2001, we entered into a supplemental indenture to the Indenture that contains provisions, which, if they become effective, will amend and restate the Indenture to release its lien on our property. This amended and restated indenture (the "Restated Indenture") will become effective when all obligations under the Indenture issued prior to September 1, 2001, cease to be outstanding or when the holders of those obligations consent to the effectiveness of the Restated Indenture. We have $1.0 million of obligations issued under the Indenture prior to September 1, 2001, the holders of which have not consented to the effectiveness of the Restated Indenture. We have the ability to redeem these obligations on any June 1 or December 1, following appropriate notice to the holders of those obligations. The amendment and restatement may not occur, however, if, immediately afterwards, an event of default exists under the Indenture or an event of default would occur. The release of a subordinated mortgage on our interest in Clover Unit 2 also is to be obtained prior to the amendment and restatement. After the date the Restated Indenture becomes effective, the obligations outstanding under the Restated Indenture will be unsecured general obligations, ranking equally and ratably with all of our other unsecured and unsubordinated obligations.

ITEM 3. LEGAL PROCEEDINGS

NOVEC

Over the past several years, we have had discussions and negotiations with NOVEC about changing the nature of its wholesale power contract from an all-requirements contract to a partial-requirements contract. Our board of directors is composed of representatives of our member distribution cooperatives and we must reach consensus among our member distribution cooperatives before any change to any of our wholesale power contracts can be made. Building a consensus for any change is difficult because any change in our rate setting methodology or provisions of service affects our various member distribution cooperatives differently.

On January 5, 2006, NOVEC filed a complaint with FERC pursuant to Section 206 of the Federal Power Act seeking reformation of its wholesale power contract. Specifically, NOVEC sought "to modify its wholesale power contract to allow NOVEC the flexibility to acquire power and energy over and above that available from NOVEC's share of Old Dominion's existing resources." NOVEC claimed that the wholesale power contract's terms were no longer just and reasonable or in the public interest because the contract was entered into in 1983, and amended and restated in 1992, prior to an allegedly different era of open transmission access and wholesale power markets. NOVEC stated in the complaint that it would not seek to be relieved of its obligations pertaining to its share of our existing power supply resources. Obligations pertaining to our existing resources include debt service, lease rentals, operation and maintenance expenses, interest coverage requirements and other costs and expenses related to our electric generating facilities and existing power purchase arrangements. On March 2, 2006, FERC denied NOVEC's complaint. On April 3, 2006, NOVEC filed a request for rehearing and on May 1, 2006, FERC issued a tolling order to allow additional time to consider the issues. On August 24, 2006, FERC issued it final order denying NOVEC's request for rehearing. On October 20, 2006, NOVEC appealed FERC's denial in the United States Court of Appeals for the District of Columbia. We have intervened in this proceeding. On March 5, 2007, the court issued the procedural schedule and NOVEC's brief is scheduled to be filed on or before May 7, 2007.

We intend to continue to vigorously contest NOVEC's claim and we will not amend or modify the wholesale power contract in any way that could adversely affect our financial condition or that of our other member distribution cooperatives.

Norfolk Southern

In April 1989, we entered into a coal transportation agreement with Norfolk Southern Railway Company ("Norfolk Southern") for delivery of coal to Clover. The agreement, which was later assigned to Virginia Power as operator of Clover, had an initial 20-year term and provides that the amounts payable for coal transportation services are subject to adjustment based on a reference index. In October 2003, Norfolk Southern claimed that it had been using an incorrect reference index to calculate amounts due to it since the inception of the agreement, and that it would begin to escalate prices for these services in the future based on an alternate reference index. On November 26, 2003, together with Virginia Power, we filed suit against Norfolk Southern in the Circuit Court of Halifax County, Virginia, seeking an order to clarify the price escalation provisions in the coal transportation agreement. In its reply to our suit, Norfolk Southern filed a counter-claim and sought (1) recovery from Virginia Power and us for additional amounts resulting from its use of the alternate reference index since December 1, 2003, and (2) an order requiring the parties to calculate the amounts Norfolk Southern claims it was underpaid since the inception of the agreement by using the alternate reference index.

On December 22, 2004, the court found in favor of Norfolk Southern on the issue of ambiguity and held that the price escalation provisions in the agreement were clear and unambiguous. The court later denied Virginia Power's and our motion to file an amended complaint based on additional evidence that was not considered by the court in the original proceedings. The court permitted Virginia Power and us to file an amended answer to Norfolk Southern's counter-claims and our amended answer was filed on March 4, 2005.

On September 1, 2006, the court granted Norfolk Southern's request to substantially dispose of the issues in the case. On September 23, 2006, we, along with Virginia Power, appealed the court's order to the Supreme Court of Virginia. On December 13, 2006, Norfolk Southern filed a motion to dismiss for lack of jurisdiction, contending that we and Virginia Power failed to timely appeal. We intend to vigorously prosecute the appeal, if the Supreme Court of Virginia determines we are able to appeal.

We recorded a liability related to the Norfolk Southern dispute and created the related regulatory asset. The regulatory asset was amortized over 21 months (April 1, 2005 through December 31, 2006) and was fully amortized and collected through rates as of December 31, 2006. The current period charges are being collected through rates. If it is ultimately determined that we owe any such amounts to Norfolk Southern, the amounts are not expected to have a material impact on our financial position or results of operations due to our ability to collect such amounts through rates charged to our member distribution cooperatives.

Ragnar Benson

In December 2002, we entered into a contract with Ragnar Benson, Inc. ("RBI") for engineering, procurement and construction services relating to the construction of our Marsh Run combustion turbine facility. Construction of the facility began in April 2003 and the facility was required to be substantially complete in the second quarter of 2004. The facility ultimately became available for commercial operation on September 15, 2004, but is still not substantially complete according to the terms of the contract. On December 23, 2004, we terminated the contract with RBI for default and filed suit in the U.S. District Court for the Eastern District of Virginia, Richmond Division, against RBI seeking liquidated damages for delay in completion of the project up to $15.0 million and damages for breach of contract up to $5.0 million. RBI counterclaimed for damages exceeding $15.0 million related to conditions they claim to have encountered during construction. We filed an answer to RBI's counterclaim denying any liability to RBI. During the discovery phase of the legal proceeding, RBI revised its claim from $15.0 million to $33.0 million.

On September 27, 2005, the U.S. District Court for the Eastern District of Virginia, Richmond Division, ruled on motions for partial summary judgment in our claims against RBI. Specifically, the court granted our motion for partial summary judgment pertaining to claims of entitlement to a change order and fraud allegations, it dismissed six of RBI's counterclaims, including all counterclaims pertaining to fraud, and it limited our possible recovery of liquidated damages to the liquidated damages cap of approximately $4.7 million. The trial began

October 11, 2005 and concluded October 26, 2005. During the trial, RBI revised its claim from $33.0 million to $36.0 million.

RBI and its parent companies, The Austin Company and Austin Holdings, Inc., filed for bankruptcy under Chapter 11 of the bankruptcy code on October 14, 2005. The automatic litigation stay was lifted for our litigation with RBI.

On June 13, 2005, we executed an agreement with RBI's surety, Seaboard Surety Company ("Seaboard"), under which it assumed all responsibilities for the final completion of the Marsh Run facility in accordance with the terms of the original agreement with RBI. Because RBI declared bankruptcy during the legal proceeding, we served a lawsuit against Seaboard on February 10, 2006, in order to enforce the eventual outcome of the suit with RBI.

On August 4, 2006, the court ruled in our favor on all remaining issues in the case and awarded us damages of $5.2 million plus expenses. On January 22, 2007, the court entered its final order awarding us an additional $2.5 million for attorneys' fees and certain other costs and expenses. On February 1, 2007, we filed a motion to amend the final order to address our claim for expert witness fees and interest from the date of the trial, totaling approximately $0.8 million. This motion is still pending before the court. After the court rules on this motion, the judgment is final and the appeals process may begin. RBI will have 30 days to appeal any of the court's rulings. We intend to enforce the court's rulings against RBI, to the extent permitted by its bankruptcy proceeding, and against Seaboard.

FERC Proceedings Related to Potential Reorganization

On October 5, 2004, we, together with New Dominion, filed an application at FERC requesting that FERC approve the assignment of our existing wholesale power contracts with our twelve member distribution cooperatives to New Dominion and accept certain changes to our cost-of-service formula to conform it for use by New Dominion for the billing of its sales to the member distribution cooperatives. On December 7, 2004, we filed an application for approval of a new tariff for sales to New Dominion, with charges determined under a cost allocation formula.

On January 14, 2005, NOVEC intervened in the FERC proceedings related to the proposed reorganization. See "Member Distribution Cooperatives—New Dominion" and "—NOVEC" in Item 1 and "NOVEC" in Legal Proceedings above. Other interveners in these proceedings included Bear Island Paper Company, LLP and the VSCC.

On March 8, 2005, FERC issued an order that set the proposed assignment of the wholesale power contracts for hearing on the limited issue of whether an Old Dominion credit downgrade could raise rates, and, if so, whether the downgrade is due to the proposed transaction. The hearing was conducted on October 18 through 20, 2005, and concluded on November 2, 2005. The initial decision was issued on February 2, 2006, and the judge ruled in our favor on all material issues. On December 21, 2006, FERC issued an order affirming the initial decision indicating that it had not been shown that the credit downgrade experienced by ODEC could raise rates. On January 22, 2007, NOVEC filed a request for rehearing and on February 21, 2007, FERC issued a tolling order to allow for additional time for consideration of the matters.

Also on March 8, 2005, FERC consolidated the October 5, 2004, and December 7, 2004, rate applications and set hearing and settlement procedures. On June 10, 2005, formal settlement procedures were terminated and a judge was assigned to hear the case. Informal settlement talks continued, and on October 13, 2005, we joined with New Dominion in filing a proposed settlement agreement that resolved all issues in dispute in these proceedings among us, Bear Island Paper Company, LLP, and the Virginia VSCC. On December 23, 2005, the judge certified the partial settlement to FERC with a recommendation that it be approved. FERC issued an order approving the partial settlement on April 7, 2006, leaving NOVEC, FERC staff and us as participants in the proceeding. The hearing was conducted on October 17 through 19, 2006, and the initial decision was issued on February 5, 2007, when the judge ruled in our favor on all material matters. NOVEC and FERC staff filed exceptions to the ruling on March 7, 2007 and we have 20 days to respond.

Other

Other than the issues discussed above and certain other legal proceedings arising out of the ordinary course of business that management believes will not have a material adverse impact on our results of operations or financial condition, there is no other litigation pending or threatened against us.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Not Applicable

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data below present selected historical information relating to our financial condition and results of operations. The financial data for the five years ended December 31, 2006, are derived from our audited consolidated financial statements. You should read the information contained in this table together with our consolidated financial statements, the related notes to the consolidated financial statements, and the discussion of this information in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7.

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(in thousands, except ratios)				
Statement of Operations Data:					
Operating Revenues	$ 817,515	$ 737,679	$ 588,451	$ 535,576	$ 494,642
Operating Margin	73,461	68,196	61,615	57,941	43,983
Net Margin[1]	21,244	12,109	12,134	12,056	9,996
Margins for Interest Ratio	1.39	1.22	1.25	1.31	1.20

	December 31,				
	2006	2005	2004	2003	2002
	(in thousands, except ratios)				
Balance Sheet Data:					
Net Electric Plant	$ 1,047,089	$ 1,074,226	$ 1,101,495	$ 1,085,406	$ 938,086
Investments	286,956	254,813	250,520	276,998	278,218
Other Assets	293,364	383,327	198,323	199,932	213,755
Total Assets	$ 1,627,409	$ 1,712,366	$ 1,550,338	$ 1,562,336	$ 1,430,059
Capitalization:					
Patronage Capital	$ 293,077	$ 271,833	$ 259,724	$ 247,590	$ 235,534
Accumulated Other Comprehensive (Loss)/Income	-	-	-	-	(10,911)
Non-controlling Interest	10,993	25,062	8,225	-	-
Long-term Debt	813,264	832,980	852,910	873,041	750,682
Total Capitalization	$ 1,117,334	$ 1,129,875	$ 1,120,859	$ 1,120,631	$ 975,305
Equity Ratio[2]	26.5%	24.6%	23.3%	22.1%	23.9%

(1) Net Margin for 2006 includes an additional equity contribution of $9.0 million.
(2) Equity ratio equals patronage capital divided by the sum of our long-term debt and patronage capital.

Our Indenture obligates us to establish and collect rates for service to our member distribution cooperatives, which are reasonably expected to yield a margin for interest ratio for each fiscal year equal to at least 1.10, subject to any necessary regulatory or judicial approvals. The Indenture requires that these amounts, together with other moneys available to us, provide us moneys sufficient to remain in compliance with our obligations under the Indenture. We calculate the margins for interest ratio by dividing our margins for interest by our interest charges.

Margins for interest under the Indenture equal:

- our net margins;
- plus revenues that are subject to refund at a later date which were deducted in the determination of net margins;
- plus non-recurring charges that may have been deducted in determining net margins;
- plus total interest charges (calculated as described below);
- plus income tax accruals imposed on income after deduction of total interest for the applicable period.

In calculating margins for interest under the Indenture, we factor in any item of net margin, loss, income, gain, earnings or profits of any of our affiliates or subsidiaries, only if we have received those amounts as a dividend or other distribution from the affiliate or subsidiary or if we have made a contribution to, or payment under a guarantee or like agreement for an obligation of, the affiliate or subsidiary. Any amounts that we are required to refund in subsequent years do not reduce margins for interest as calculated under the Indenture for the year the refund is paid.

Interest charges under the Indenture equal our total interest charges (other than capitalized interest) related to (1) all obligations under the Indenture, (2) indebtedness secured by a lien equal or prior to the lien of the Indenture, and (3) obligations secured by liens created or assumed in connection with a tax-exempt financing for the acquisition or construction of property used by us, in each case including amortization of debt discount and expense or premium.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Caution Regarding Forward Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward looking statements regarding matters that could have an impact on our business, financial condition, and future operations. These statements, based on our expectations and estimates, are not guarantees of future performance and are subject to risks, uncertainties, and other factors that could cause actual results to differ materially from those expressed in the forward looking statements. These risks, uncertainties, and other factors include, but are not limited to, general business conditions, increased competition in the electric utility industry, demand for energy, federal and state legislative and regulatory actions and legal and administrative proceedings, changes in and compliance with environmental laws and policies, weather conditions, the cost of commodities used in our industry, and unanticipated changes in operating expenses and capital expenditures. Our actual results may vary materially from those discussed in the forward looking statements as a result of these and other factors. Any forward looking statement speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward looking statement or statements to reflect events or circumstances after the date on which the statement is made even if new information becomes available or other events occur in the future.

Basis of Presentation

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative ("ODEC" or "we" or "our"), its subsidiaries and TEC Trading, Inc. ("TEC"). See Note 1—Summary of Significant Accounting Policies in Note 1 in the Notes to the Consolidated Financial Statements in Item 8.

Overview

ODEC is a not-for-profit power supply cooperative owned entirely by its twelve member distribution cooperatives and a thirteenth member, TEC. We supply our member distribution cooperatives' power requirements, consisting of capacity requirements and energy requirements, through a portfolio of resources including generating facilities, long-term and short-term physically-delivered forward power purchase contracts, and spot market purchases.

Our financial results for the year ended December 31, 2006, were significantly impacted by changing conditions in the power markets. As prices for energy and natural gas fell in 2006, the fair value of our forward purchase power contracts and natural gas futures, which we use to mitigate market price risk, decreased. This was the primary reason for the decrease in our regulatory liabilities, and the corresponding reduction in our net cash provided by operating activities. Although spot market prices for energy and natural gas were generally lower in 2006 as compared to 2005, our purchased power and fuel expense increased because we acquired or hedged the majority of our 2006 power needs in prior years, and our reliance on the spot market was minimal.

Critical Accounting Policies

The preparation of our financial statements in conformity with generally accepted accounting principles requires that our management make estimates and assumptions that affect the amounts reported in our financial statements. We base these estimates and assumptions on information available as of the date of the financial statements and they are not necessarily indicative of the results to be expected for the year. We consider the following accounting policies to be critical accounting policies due to the estimation involved in each.

Accounting for Rate Regulation

We are a rate-regulated entity and, as a result, are subject to the accounting requirements of Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for Certain Types of Regulation." In accordance with SFAS No. 71, some of our revenues and expenses can be deferred at the discretion of our board of directors, which has budgetary and rate setting authority, if it is probable that these amounts will be refunded or recovered through our formulary rate in future years. Regulatory assets on our Consolidated Balance Sheet are costs that we expect to recover from our member distribution cooperatives based on rates approved by our board of directors in accordance with our formulary rate. Regulatory liabilities on our Consolidated Balance Sheet represent probable future reductions in our revenues associated with amounts that we expect to refund to our member distribution cooperatives based on rates approved by our board of directors in accordance with our formulary rate. See "—Factors Affecting Results—Formulary Rate" below. Regulatory assets are generally included in deferred charges and regulatory liabilities are generally included in deferred credits and other liabilities. We recognize regulatory assets and liabilities as expenses or as a reduction in expenses, concurrent with their recovery through rates.

Deferred Energy

In accordance with SFAS No. 71, we use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. Deferred energy expense on our Consolidated Statement of Revenues, Expenses and Patronage Capital represents the difference between energy revenues and energy expenses. The deferred energy balance on our Consolidated Balance Sheet represents the net accumulation of any under- or over-collection of energy costs. Under-collected energy costs appear as an asset on our Consolidated Balance Sheet and will be collected from our member distribution cooperatives in subsequent periods through our formulary rate. Conversely, over-collected energy costs appear as a liability on our Consolidated Balance Sheet and will be refunded to our member distribution cooperatives in subsequent periods through our formulary rate.

Margin Stabilization Plan

We have a Margin Stabilization Plan that allows us to review our actual capacity-related costs of service and capacity revenue as of year end and adjust revenues from our member distribution cooperatives to meet our financial coverage requirements and accumulate additional equity as approved by our board of directors. Our formulary rate allows us to recover and refund amounts under the Margin Stabilization Plan. We record all adjustments, whether increases or decreases, in the year affected and allocate any adjustments to our member distribution cooperatives based on power sales during that year. We collect these increases from our member distribution cooperatives, or offset decreases against amounts owed by our member distribution cooperatives to us, in the succeeding calendar year. Each quarter we adjust revenues and accounts payable—members or accounts receivable, as appropriate, to reflect these adjustments. In 2006 and 2005, under our Margin Stabilization Plan, we reduced operating revenues by $2.8 million and $13.3 million, respectively, and increased accounts payable—members by the same amounts. There was no adjustment to operating revenues under our Margin Stabilization Plan in 2004.

Accounting for Asset Retirement Obligations

We adopted SFAS No. 143 "Accounting for Asset Retirement Obligations" effective January 1, 2003. SFAS No. 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. In the absence of quoted market prices, we estimate the fair value of our asset retirement obligations using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit-adjusted risk-free rate. Asset retirement obligations currently reported on our Consolidated Balance Sheet were measured during a period of historically low interest rates. The impact on measurements of new asset retirement obligations using different rates in the future may be significant.

In March 2005, the FASB issued Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations, an Interpretation of Financial Accounting Standards Board ("FASB") Statement No. 143" ("FIN 47"). FIN 47 is a further clarification of SFAS No. 143 and requires the establishment of a liability for conditional asset retirement obligations. A conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Uncertainty about the timing and/or method of settlement is required to be considered in the measurement of the liability when sufficient information exists. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. We adopted FIN 47 as of December 31, 2005, and the impact on our results of operations and financial condition was immaterial.

A significant portion of our asset retirement obligations relates to our share of the future decommissioning of the North Anna Nuclear Power Station ("North Anna"). At December 31, 2006, North Anna's nuclear decommissioning asset retirement obligation totaled $51.5 million, which represented approximately 92.3% of our total asset retirement obligations. Because of its significance, the following discussion of critical assumptions inherent in determining the fair value of asset retirement obligations relates to those associated with our nuclear decommissioning obligations.

We obtain from third-party experts periodic site-specific "base year" cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for North Anna. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual results. In addition, these estimates are dependent on subjective factors, including the selection of cost escalation rates, which we consider to be a critical assumption. These studies were last performed in 2005 and received in 2006.

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. The weighted average cost escalation rate used for the study performed in 2002 was 3.27%. The weighted average cost escalation rate used for the study performed in 2005 was 2.42% and this rate was applied when the cash flows increased as compared to the cash flows in the 2002 study. If the cash flows decreased, the 2002 rate of 3.27% was applied. The use of alternative rates would have been material to the liabilities recognized. For example, had we increased the cost escalation rates by 0.5% to 3.77% and 2.92%, the amount recognized as of December 31, 2006, for our asset retirement obligations related to nuclear decommissioning would have been $10.4 million higher.

Accounting for Derivative Contracts

We primarily purchase power under both long-term and short-term physically-delivered forward contracts to supply power to our member distribution cooperatives under our wholesale power contracts with them. See "Member Distribution Cooperatives — Wholesale Power Contracts" in Item 1. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of the forward purchase derivative contracts qualify for the normal purchases/normal sales accounting exception under SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities." As a result, these contracts are not recorded at fair value. We record a liability and purchased power expense when the power under the forward physical delivery contract is delivered. We also purchase natural gas futures generally for three years or less to hedge the price of natural gas for the operation of our combustion turbine facilities and for use as a basis in determining the price of power in certain forward power purchase agreements. These derivatives do not qualify for the normal purchases/normal sales accounting exception.

For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we may elect cash flow hedge accounting in accordance with SFAS No. 133. Accordingly, gains and losses on derivative contracts are deferred into Other Comprehensive Income until the hedged underlying transaction occurs or is no longer likely to occur. For derivative contracts where hedge accounting is not utilized, or for which ineffectiveness exists, we defer all remaining gains and losses on a net basis as a regulatory asset or liability in accordance with SFAS No. 71. These amounts are subsequently reclassified as purchased power or fuel expense in our Consolidated Statements of Revenues, Expenses, and Patronage Capital as the power or fuel is delivered and/or the contract settles.

Generally, derivatives are reported on the Consolidated Balance Sheet at fair value. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications. For individual contracts, the use of differing assumptions could have a material effect on the contract's estimated fair value.

Factors Affecting Results

Formulary Rate

Our power sales are comprised of two power products – energy and capacity (also referred to as demand). Energy is the physical electricity delivered through transmission and distribution facilities to customers. We must have sufficient committed energy available to us for delivery to our member distribution cooperatives to meet their maximum energy needs at any time, with limited exceptions. This committed available energy at any time is referred to as capacity.

The rates we charge our member distribution cooperatives for sales of energy and capacity are determined by a formulary rate accepted by the Federal Energy Regulatory Commission ("FERC") which is intended to permit collection of revenues which will equal the sum of:

- all of our costs and expenses;
- 20% of our total interest charges; and
- additional equity contributions approved by our board of directors.

The formulary rate has three main components: a demand rate, a base energy rate and a fuel factor adjustment rate. The formulary rate identifies the cost components that we can collect through rates, but not the actual amounts to be collected. With limited minor exceptions, we can change our rates periodically to match the costs we have incurred and we expect to incur without seeking FERC approval.

Energy costs, which are primarily variable costs, such as nuclear, coal and natural gas fuel costs and the energy costs under our power purchase contracts with third parties, are recovered through the two separate rates, the base energy rate and the fuel factor adjustment rate. The base energy rate is a fixed rate that requires FERC approval prior to adjustment. However, to the extent the base energy rate over- or under-collects our energy costs, we refund or collect the difference through a fuel factor adjustment rate. We review our energy costs at least every six months to determine whether the base energy rate and the current fuel factor adjustment rate together are adequately recovering our actual and anticipated energy costs, and revise the fuel factor adjustment rate accordingly. Since the fuel factor adjustment rate can be revised without FERC approval, we can effectively change our total energy rate to recover all our energy costs without seeking the approval of FERC.

Capacity costs, which are primarily fixed costs, such as depreciation expense, interest expense, administrative and general expenses, capacity costs under power purchase contracts with third parties, transmission costs, and our margin requirements and additional amounts approved by our board of directors are recovered through our demand rate. The formulary rate allows us to change the actual demand rate we charge as our capacity related costs change, without seeking FERC approval, with the exception of decommissioning cost, which is a fixed number in the formulary rate that requires FERC approval prior to any adjustment. FERC approval is also needed to change account classifications currently in the formula or to add accounts not otherwise included in the current formula. Additionally, future depreciation studies are to be filed with FERC for their approval if it would result in a change in our depreciation rates. Our demand rate is revised automatically to recover the costs contained in our budget and any revisions made by our board of directors to our budget.

Recognition of Revenue

Our operating revenues on our Consolidated Statement of Revenues, Expenses and Patronage Capital reflect the actual capacity-related costs we incurred plus the energy costs that we collected during each calendar quarter and at year-end. Estimated capacity-related costs are collected during the period through the demand component of our formulary rate. In accordance with our Margin Stabilization Plan, these costs, as well as operating revenues, are adjusted at the end of each reporting period to reflect actual costs incurred during that period. See "—Critical Accounting Policies—Margin Stabilization Plan." Estimated energy costs are collected during the period through the base energy rate and the fuel factor adjustment rate. Energy costs and operating revenues are not adjusted at the end of each reporting period to reflect actual costs incurred during that period. The difference between actual energy costs incurred and energy costs collected during each period is recorded as deferred energy expense. See "—Critical Accounting Policies—Deferred Energy."

We bill energy to each of our member and non-member customers based on the total megawatt-hours ("MWh") delivered to them each month. We bill capacity to each of our member distribution cooperatives based on its requirement for energy during the hour of the month when the need for energy among all of the consumers in the Virginia mainland or the Delmarva Peninsula, as applicable, is highest, measured in megawatts ("MW").

Consumers' Requirements for Power

Growth in the number of consumers and growth in consumers' requirements for power significantly affect our member distribution cooperatives' consumers' requirements for power. Factors affecting our member distribution cooperatives' consumers' requirements for power include weather, as well as the amount, size, and usage of electronics and machinery and the expansion of operations among their commercial and industrial customers.

Weather

Weather affects the demand for electricity. Relatively higher or lower temperatures tend to increase the demand for energy to use air conditioning and heating systems. Mild weather generally reduces the demand because heating and air conditioning systems are operated less.

Power Supply Resources

Market forces influence the structure of new power supply contracts into which we enter. When we enter into long-term power purchase contracts or agree to purchase energy at a date in the future, we rely on models based on our judgments and assumptions of factors such as future demand for power and market prices of energy and the price of commodities, such as natural gas used to generate electricity. Our actual results may vary from what our models predict, which may in turn impact our resulting costs to our members. Additionally, our models become less reliable the further into the future that the estimates are made.

We satisfy the majority of our member distribution cooperatives' capacity requirements and slightly less than half of their energy requirements through our ownership interests in the Clover Power Station ("Clover"), North Anna, the Louisa Generating Facility ("Louisa"), the Marsh Run Generating Facility ("Marsh Run"), and the Rock Springs Generating Facility ("Rock Springs"), and we purchase power under long-term and short-term physically-delivered forward contracts and in the spot market to supply the remaining needs of our member distribution cooperatives.

Our operating expenses are significantly affected by the extent to which we purchase power and, relatedly, the availability of our base load generating facilities, Clover and North Anna. Base load generating facilities, particularly nuclear power plants such as North Anna, generally have relatively high fixed costs. Nuclear facilities operate with relatively low variable costs due to lower fuel costs and technological efficiencies. In addition, coal-fired facilities have relatively low variable costs, as compared to combustion turbine facilities such as Louisa, Marsh Run and Rock Springs. Owners of power plants incur the fixed costs of these facilities whether or not the units operate. When either Clover or North Anna is off-line, we must purchase replacement energy from either Virginia Electric & Power Company ("Virginia Power") or from the market. As a result, our operating expenses, and consequently our rates to our member distribution cooperatives, are significantly affected by the operations of Clover and North Anna but not our combustion turbine facilities. Our combustion turbine facilities have relatively low fixed costs and greater operational flexibility; however, they are more expensive to operate and, as a result, we will operate them only when the market price of energy makes their operation economical or when their operation is required by PJM for system reliability purposes. The output of Clover and North Anna for the past three years as a percentage of maximum dependable capacity rating of the facilities was as follows:

	Clover			North Anna		
	Year Ended December 31,			Year Ended December 31,		
	2006	2005	2004	2006	2005	2004
Unit 1	90.8 %	86.7 %	82.2 %	88.2 %	99.9 %	91.3 %
Unit 2	91.3	80.7	92.2	99.7	91.3	91.7
Combined	91.1	83.7	87.2	94.0	95.6	91.5

Clover

Clover Unit 1 was off-line five days in 2006, nine days in 2005, and 37 days in 2004 for scheduled maintenance. Clover Unit 1 was off-line approximately two days in 2006 and eight days in 2005 for minor unscheduled outages.

Clover Unit 2 was off-line five days in 2006, 34 days in 2005, and five days in 2004 for scheduled maintenance. Clover Unit 2 was off-line approximately two days in 2006 and nine days in 2005 for minor unscheduled outages.

On May 1, 2005, operational control of Virginia Power's transmission facilities was transferred to PJM Interconnection, LLC ("PJM"). With that transfer, all of our member distribution cooperatives' capacity and energy requirements are now within the PJM control area and our generating facilities are now under dispatch control of PJM. Accordingly, Clover Units 1 and 2 are operated pursuant to PJM dispatching requirements. During 2005, Clover Units 1 and 2 were dispatched less by PJM than they were by Virginia Power in prior years. When our generating facilities are dispatched less, we purchase more power to meet the needs of our member distribution cooperatives.

North Anna

North Anna Unit 1 was off-line for 29 days for a scheduled refueling and maintenance outage during 2006. North Anna Unit 1 experienced minor unscheduled outages during 2005 and was off-line 24 days in 2004 for a scheduled refueling outage.

North Anna Unit 2 experienced minor unscheduled outages during 2006 and 2005. North Anna Unit 2 was off-line for 28 days in 2005 and 28 days in 2004 for a scheduled refueling outage.

Combustion turbine facilities

During 2006, 2005, and 2004, the operational availability of our Louisa, Marsh Run, and Rock Springs combustion turbine facilities was as follows:

	Year Ended December 31,		
	2006	2005	2004
Louisa	99.2 %	98.2 %	96.8 %
Marsh Run	93.6	97.4	90.5
Rock Springs	91.2	95.8	96.5

Margins

We operate on a not-for-profit basis and, accordingly, seek to generate revenues sufficient to recover our cost of service and produce margins sufficient to establish reasonable reserves, meet financial coverage requirements, and accumulate additional equity approved by our board of directors. Revenues in excess of expenses in any year are designated as net margins in our Consolidated Statements of Revenues, Expenses and Patronage Capital. We designate retained net margins in our Consolidated Balance Sheets as patronage capital, which we assign to each of our members on the basis of its class of membership and business with us. Any distributions of patronage capital are subject to the discretion of our board of directors and restrictions contained in our Indenture.

Indenture Rate Covenant

Under the Indenture, we are required, subject to any necessary regulatory or judicial approvals, to establish and collect rates reasonably expected to yield margins for interest for each fiscal year equal to at least 1.10 times our total interest charges for the fiscal year. The Indenture requires that these amounts, together with other moneys available to us, provide us moneys sufficient to remain in compliance with our obligations under the Indenture. See Item 6, "Selected Financial Data" for a description of the calculations of margins for interest and interest charges under the Indenture, and "—Restated Indenture" in Item 2 for a discussion of the effect of a possible amendment and restatement of the Indenture.

Results of Operations

Operating Revenues

Operating revenues are derived from power sales to our members and non-members. Sales to members include sales to our Class A members, which are our twelve distribution cooperative members, and, for 2004, sales to our single Class B member, TEC. Our operating revenues by type of purchaser for the past three years were as follows:

	Year Ended December 31,		
	2006	2005	2004
Revenues from sales to members:		(in thousands)	
Member distribution cooperatives	$ 746,506	$ 657,022	$ 564,624
TEC	-	-	18,890
Total revenues from sales to members	746,506	657,022	583,514
Revenues from sales to non-members	71,009	80,657	4,937
Total revenues	$ 817,515	$ 737,679	$ 588,451

In accordance with Financial Accounting Standards Board Interpretation No. 46R, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51" ("FIN 46"), TEC is considered a variable interest entity for which Old Dominion was the primary beneficiary. Beginning in 2005, the income statement of TEC is consolidated and the inter-company revenues and expenses are eliminated in consolidation. Beginning January 1, 2005, we reported no sales to TEC because TEC is now consolidated as a result of the adoption of FIN 46. TEC's sales to third parties are reflected as non-member revenues.

Sales to Member Distribution Cooperatives

Revenues from sales to our member distribution cooperatives are a function of our formulary rate for sales of power to our member distribution cooperatives and our member distribution cooperatives' consumers' requirements for power. Our formulary rate is based on our cost of service in meeting these requirements. See "—Factors Affecting Results—Formulary Rate."

Our revenues from sales to our member distribution cooperatives by formulary rate component, energy sales to our member distribution cooperatives, and average costs to our member distribution cooperatives per MWh for the past three years were as follows:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Revenues from sales to member distribution cooperatives:			
Base energy revenues	$ 198,376	$ 200,993	$ 189,897
Fuel factor adjustment revenues	317,652	232,345	141,795
Total energy revenues	516,028	433,338	331,692
Demand (capacity) revenues	230,478	223,684	232,932
Total revenues from sales to member distribution cooperatives	$ 746,506	$ 657,022	$ 564,624
Energy sales to member distribution cooperations (in MWh)	11,026,284	11,191,729	10,518,241
Average costs to member distribution cooperatives (per MWh)(1)	$ 67.70	$ 58.71	$ 53.68

(1) Our average costs to our member distribution cooperatives is based on the blended cost of power from all of our power supply resources.

2006 Compared to 2005

Total revenues from sales to our member distribution cooperatives for the year ended December 31, 2006, increased $89.5 million, or 13.6%, as compared to the same period in 2005, primarily as a result of higher energy rates.

Our total energy rate (including our base energy rate and our fuel factor adjustment rate) was 20.9% higher, on a per MWh basis, for the year ended December 31, 2006, as compared to the same period in 2005. Due to continued increases in our energy costs and the need to collect revenues to reduce our deferred energy balance, we increased our fuel factor adjustment rate effective April 1, 2006, and again on October 1, 2006, resulting in an increase to our total energy rate of approximately 11.9% and 5.2%, respectively. Energy sales volumes were essentially flat, decreasing approximately 1.5% in 2006 as compared to 2005.

The capacity costs we incurred, and thus the capacity-related revenues we reflected, increased $6.8 million, or 3.0% for the year ended December 31, 2006, as compared to the same period in 2005, as a result of the collection of $9.0 million in additional equity contribution partially offset by decreases in our transmission and general and administrative costs.

Our average costs per MWh to member distribution cooperatives increased $8.99 per MWh, or 15.3%, for the year ended December 31, 2006, as compared to the same period in 2005, as a result of the increase in our total energy rate.

2005 Compared to 2004

Total revenues from sales to our member distribution cooperatives for the year ended December 31, 2005, increased $92.4 million, or 16.4%, as compared to the same period in 2004, primarily as a result of higher energy rates and increased sales of energy.

Our total energy rate (including our base energy rate and our fuel factor adjustment rate) was 22.8% higher, on a per MWh basis, for the year ended December 31, 2005, as compared to the same period in 2004. Due to continued higher energy costs in 2005, we increased our fuel factor adjustment rate effective April 1, 2005, resulting in an increase to our total energy rate of approximately 14.6%. During 2005, energy costs continued to rise and we increased our fuel factor adjustment rate effective October 1, 2005, resulting in an increase to our total energy rate of approximately 8.1%.

Sales volumes increased approximately 6.4% as a result of colder weather experienced by customers of our member distribution cooperatives in March of 2005 as compared to the same period in 2004, and warmer weather in June through September 2005 as compared to the same period in 2004, which created a greater requirement for power to operate heating and air conditioning systems.

The capacity costs we incurred, and thus the capacity-related revenues we reflected, for the year ended December 31, 2005, as compared to the same period in 2004, decreased $9.2 million, or 4.0%, primarily as a result of lower demand costs incurred in 2005.

Our average costs per MWh to member distribution cooperatives increased $5.03 per MWh, or 9.4%, for the year ended December 31, 2005, as compared to the same period in 2004, as a result of the increase in our total energy rate, partially offset by the increase in sales volumes.

Sales to TEC

In accordance with Financial Accounting Standards Board Interpretation No. 46R, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51" ("FIN 46"), TEC is considered a variable interest entity for which Old Dominion was the primary beneficiary. Beginning in 2005, the income statement of TEC was consolidated and the inter-company revenues and expenses were eliminated in consolidation. Beginning January 1, 2005, we reported no sales to TEC because TEC was consolidated as a result of the adoption of FIN 46. TEC's sales to third parties are reflected as non-member revenues. Prior to January 1, 2005, sales to TEC consisted primarily of sales of excess energy that we did not need to meet the requirements of our member distribution cooperatives. We sold the portion of this energy that could not be utilized by our member distribution cooperatives to TEC for resale into the market, or to non-members.

Sales to Non-Members

Sales to non-members consist of sales of excess purchased energy and sales of excess generated energy. We primarily sell excess energy to PJM under its rates for providing energy imbalance services. Excess energy is sold at the prevailing market price at the time of sale and is the result of changes in our purchased power portfolio, differences between actual and forecasted needs, as well as changes in market conditions. Prior to May 1, 2005, we also sold excess energy from Clover to Virginia Power pursuant to the requirements of the Clover operating agreement. Non-member revenue decreased by $9.6 million, or 12.0%, in 2006 as compared to the same period in 2005 due to the decrease in the average price at which we sold excess energy. Beginning in 2005, TEC's sales to third parties were reflected as sales to non-members. Our non-member energy sales in MWh for 2006, 2005, and 2004, were 1,349,473, 1,318,647, and 87,836, respectively.

Operating Expenses

We supply our member distribution cooperatives' power requirements, consisting of capacity requirements and energy requirements, through (1) our interests in electric generating facilities which consist of a 50% interest in Clover, an 11.6% interest in North Anna, our Louisa, Marsh Run, and Rock Springs combustion turbine facilities, and distributed generation, and (2) long-term and short-term physically-delivered forward power purchase contracts and spot purchases of power in the open market See "Power Supply Resources" in Item 1.

Components of Operating Expense

The components of our operating expenses for the years ended December 31, 2006, 2005, and 2004, were as follows:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Fuel	$ 154,931	$ 143,332	$ 90,635
Purchased power	464,047	434,557	314,763
Deferred energy	6,414	(26,135)	(8,775)
Operations and maintenance	35,551	34,221	40,595
Administrative and general	32,502	34,523	28,800
Depreciation, amortization and decommissioning	38,393	38,556	32,759
Amortization of regulatory asset/(liability), net	2,701	1,909	20,543
Accretion of asset retirement obligations	2,783	2,496	2,251
Taxes, other than income taxes	6,732	6,024	5,265
Total operating expense	$ 744,054	$ 669,483	$ 526,836

Our operating expenses are comprised of the costs that we incur to generate and purchase power to meet the needs of our member distribution cooperatives, and the costs associated with any sales of power to TEC and non-members. Our energy costs generally are variable and include fuel expense as well as the energy portion of our purchased power expense. Our capacity or demand costs generally are fixed and include depreciation, amortization and decommissioning expenses, and interest charges (a non-operating expense), as well as the capacity portion of our purchased power expense. See "Factors Affecting Results—Formulary Rate."

2006 Compared to 2005

Total operating expenses for 2006 increased $74.6 million, or 11.1%, over 2005 primarily due to the change in deferred energy expense and increases in purchased power expense and fuel expense.

Deferred energy expense changed $32.5 million, or 124.5%, as compared to 2005 reflecting an over-collection of energy costs in 2006 as compared to 2005 when we under-collected our costs. Our deferred energy balance changed from a net under-collection of energy costs of $21.3 million to a net under-collection of energy costs of $14.9 million, reflecting the fact that our energy rate allowed us to collect all of our current year energy costs as well as $6.4 million of prior year energy costs.

Purchased power expense increased $29.5 million, or 6.8%, as a result of an 11.5% increase in the average price of purchased power, partially offset by a 4.2% decrease in the volume of purchases of additional energy from the market to supply our member distribution cooperatives' requirement. Clover generated more energy in 2006 than in 2005 because it was dispatched by PJM more in 2006 than in 2005 and had fewer scheduled maintenance outage days, thereby reducing our need to purchase energy from the market.

Fuel expense increased $11.6 million, or 8.1%, primarily due to the 15.8% increase in our average price of coal partially offset by the 7.1% decrease in our average price of natural gas in 2006 as compared to 2005.

2005 Compared to 2004

Total operating expenses for 2005 increased $142.6 million, or 27.1%, over 2004 primarily due to increases in purchased power expense and fuel expense. These increases were partially offset by the change in the amortization of regulatory asset/(liability), net and the change in deferred energy expense.

Purchased power expense increased $119.8 million, or 38.1%, as a result of the purchase of additional energy from the market to supply our member distribution cooperatives' requirements and a 14.2% increase in the average price of purchased power. During 2005, Clover was dispatched less by PJM based upon economic factors, which resulted in increased purchased power.

Fuel expense increased $52.7 million, or 58.1%, primarily due to the 62.6% increase in the average price of coal and the 35.8% increase in the average price of natural gas in 2005 as compared to 2004. Marsh Run began commercial operation in September of 2004.

Amortization of regulatory asset/(liability), net changed $18.6 million, or 90.7%, resulting in decreased operating expenses primarily due to the acceleration of the amortization of a regulatory asset in 2004. This regulatory asset was established in 2002 in connection with the collection of additional amounts we collected and then paid relating to a dispute under a power purchase agreement with Public Service Gas and Electric Company ("PSE&G").

Deferred energy expense changed $17.4 million, or 197.8%, over 2004 reflecting a greater under-collection of energy costs in 2005 as compared to 2004. The $26.1 million we under-collected in 2005 changed our deferred energy balance from a $4.8 million liability at December 31, 2004, to a $21.3 million asset at December 31, 2005.

Other Items

Investment Income

Investment income increased in 2006 by $4.0 million, or 60.0%, primarily due to income earned on our increased average balances in cash and temporary investments as a result of higher member prepayments and higher interest rates.

Investment income increased in 2005 by $3.7 million, or 128.6%, as a result of both higher yields on our cash and temporary investments and higher investable balances than in 2004. We earned higher yields on our invested funds largely as a result of increased market interest rates in 2005. Our higher investable balance occurred primarily during the last five months of the 2005 when we held cash posted from counterparties under terms of our power purchase and sale agreements.

Interest Charges, Net

The primary factors affecting our interest expense are scheduled payments of principal on our indebtedness, interest related to our potential liability associated with our dispute with Norfolk Southern, and capitalized interest.

The major components of interest charges, net for the years ended December 31, 2006, 2005, and 2004, were as follows:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Interest expense on long-term debt	$ (55,542)	$ (56,700)	$ (56,252)
Other	(5,676)	(3,845)	(4,415)
Total Interest Charges	(61,218)	(60,545)	(60,667)
Allowance for borrowed funds used during construction	269	198	8,161
Interest Charges, net	$ (60,949)	$ (60,347)	$ (52,506)

Interest charges, net remained relatively flat as compared to 2005. Other interest increased $1.8 million, or 47.6%, as compared to 2005, primarily as a result of accrued interest on our potential liability related to our dispute with Norfolk Southern. Interest expense on long-term debt decreased $1.2 million as a result of our declining long-term debt balance. Interest charges, net increased in 2005 by $7.8 million, or 14.9%, as compared to 2004, primarily due to the reduction of capitalized interest associated with Marsh Run. We ceased capitalizing interest on Marsh Run in September 2004 when the facility became commercially operable. Capitalized interest is computed monthly using an interest rate, which reflects our embedded cost of indebtedness, multiplied by our investment in projects under construction.

Financial Condition

The principal changes in our financial condition from December 31, 2005 to December 31, 2006, were caused by decreases in regulatory liabilities, deferred charges—other, net electric plant, deposits, accounts payable—deposits and accounts receivable, and increases in accounts receivable—deposits and patronage capital. Regulatory liabilities decreased $43.8 million primarily due to the change in the fair value of our forward purchase power contracts and natural gas futures for which cash flow hedge accounting is not utilized. Deferred charges—other decreased $39.9 million also as a result of the decrease in the fair value of our forward purchased power contracts and natural gas futures, partially offset by the resulting increase in the amount of collateral we were required to post in connection with our natural gas futures. Net electric plant decreased $27.1 million as we continued to depreciate our existing generating facilities. Deposits and accounts payable—deposits both decreased $24.7 million. As of December 31, 2005, our counterparties were required to post $24.7 million in deposits in accordance with the terms of our respective master power purchase and sales agreements with them. At December 31, 2006, due to changes in energy prices, our counterparties were not required to post deposits. Accounts receivable decreased $21.2 million as a result of decreased sales of excess power to non-members. Accounts receivable-deposits increased $23.6 million related to collateral we were required to post with our counterparties. Patronage capital increased $21.2 million as a function of our interest coverage requirement and the additional $9.0 million that our board of directors approved to be collected through rates in 2006.

Liquidity and Capital Resources

Sources

Cash generated by our operations, issuances of indebtedness and, periodically, borrowings under available lines of credit and our revolving credit facility provide our sources of liquidity and capital.

Operations

Historically, our operating cash flows have been sufficient to meet our short- and long-term capital expenditures related to our existing generating facilities, our debt service requirements, and our ordinary business operations. Our operating activities provided cash flows of $14.5 million, $122.6 million, and $0.9 million, in 2006, 2005, and 2004, respectively. Operating activities in 2006 were primarily impacted by the change in regulatory assets and liabilities, and current liabilities, partially offset by changes in deferred charges and credits, deferred energy and current assets. Regulatory assets and liabilities changed $55.8 million primarily due to the reduction in the fair value of our derivatives. Current liabilities changed $30.9 million primarily as a result of decreased accounts payable—deposits as a result of the change in the amount of deposits posted by our counterparties in accordance with the terms of our respective master power purchase and sales agreements with them and decreased accounts payable—members as a result of a lower margin stabilization adjustment in 2006 as compared to 2005 and lower member prepayment balances. Deferred charges and credits changed $14.5 million as a result of the reduction in the fair value of our derivatives which was partially offset by the resulting increase in the amount of collateral we were required to post. At December 31, 2006, we had an under-collected deferred energy balance of $14.9 million as compared to an under-collected deferred energy balance of $21.3 million at December 31, 2005, which resulted in a cash inflow of $6.4 million. Current assets changed $3.0 million related to the changes in accounts receivable and accounts receivable deposits. Deposits decreased $24.7 million as a result of changes in deposits posted by our counterparties in accordance with the terms of our respective master power purchase and sales agreements with them. Accounts receivable decreased $21.2 million as a result of decreased purchased power receivables, which was offset by an increase of $23.6 million related to collateral we were required to post with our counterparties.

Credit Facilities

In addition to liquidity from our operating activities, we maintain committed lines of credit and revolving credit facilities to cover our short- and medium-term funding needs. Currently, we have short-term committed variable rate lines of credit in an aggregate amount of $180.0 million, all of which are available for general working capital purposes. At December 31, 2006 and 2005, we had no short-term borrowings or letters of credit outstanding under any of these arrangements. We expect these working capital lines of credit to be renewed as they expire.

Our short-term committed variable rate lines of credit are more particularly described by lender, the amount of the line of credit and the expiration date as follows:

Lender	Amount (in millions)	Expiration Date
Bank of America, N.A.	$ 30.0	September 30, 2007
Bank of America, N.A.	30.0	June 25, 2007
Branch Banking and Trust Company of Virginia	25.0	April 30, 2007
CoBank, ACB	25.0	October 30, 2007
JPMorgan Chase Bank, N.A.	70.0	May 8, 2007
	$ 180.0	

In addition to our lines of credit, we have two committed three-year revolving credit facilities, $50.0 million each, available for capital expenditures and general corporate purposes. Our revolving credit facility with CoBank, ACB expires on June 18, 2007. Our revolving credit facility with National Rural Utilities Cooperative Finance Corporation expires on January 30, 2009. As of December 31, 2006 and 2005, there were no borrowings or letters of credit outstanding under these facilities.

Our credit agreements relating to our lines of credit and revolving credit facilities contain customary events of default, which, if they occur, would terminate our ability to borrow amounts under those facilities and potentially accelerate any outstanding loans under those facilities at the election of the lender. Some of these customary events of default relate to:

- our failure to timely pay any principal and interest due under that credit facility;

- a breach by us of our representations and warranties in the credit agreement or related documents;
- a breach of a covenant contained in the credit agreement, which, in some cases we are given an opportunity to cure and, in one case, includes a debt to capitalization financial covenant;
- failure to pay, when due, other indebtedness above a specified amount;
- an unsatisfied judgment above specified amounts; and
- bankruptcy events relating to us.

Financings

We fund the portion of our capital expenditures that we are not able to supply from operations through financings in the market. Since 1983, these capital expenditures have consisted primarily of the costs related to the acquisition of our interest in North Anna, our share of the costs to construct Clover, and the development and construction of our three combustion turbine facilities. In 2006 and 2005, we did not engage in any material financing activities.

Uses

Our uses of liquidity and capital relate to funding our working capital needs, investment activities and financing activities. Substantially all of our investment activities relate to capital expenditures in connection with our generating facilities. We expect that cash flows from our operations and our existing lines of credit and revolving credit facilities will be sufficient to meet our currently anticipated operational and capital requirements.

Capital Expenditures

We regularly forecast our capital expenditures as part of our long-term business planning activities. We review these projections frequently in order to update our calculations to reflect changes in our future plans, construction costs, market factors, and other items affecting our forecasts. Our actual capital expenditures could vary significantly from these projections. The table below summarizes our actual and projected capital expenditures, including nuclear fuel and capitalized interest, for 2004 through 2009:

	Actual Year Ended December 31,			Projected Year Ended December 31,		
	2004	2005	2006	2007	2008	2009
	(in millions)					
Combustion turbine facilities	$38.5	$5.1	$0.3	$0.5	$0.5	$0.5
Clover	3.4	1.6	3.9	1.9	6.3	2.9
North Anna	11.7	13.2	14.7	15.4	15.5	15.0
Other	1.0	0.2	1.1	3.2	0.6	0.6
Total	$54.6	$20.1	$20.0	$21.0	$22.9	$19.0

Nearly all of our capital expenditures consist of additions to electric plant and equipment. Our future capital requirements include our portion of the cost of the nuclear fuel purchased for North Anna and other capital expenditures including generation facility improvements. We intend to use our cash from operations to fund all of our currently projected capital requirements through 2009.

Contractual Obligations

In the normal course of business, we enter into long-term arrangements relating to the construction, operation and maintenance of our generating facilities, power purchases, the financing of our operations and other matters. See "Business—Power Supply Resources—Power Purchase Contracts" in Item 1 and "Future Issues—Reliance on Market Purchases of Energy." The following table summarizes our long-term contractual obligations at December 31, 2006:

	Payments due by Period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in millions)		
Long-term indebtedness	$ 1,371.5	$ 69.8	$ 142.2	$ 387.5	$ 772.0
Operating lease obligations	379.3	2.7	7.7	12.2	356.7
Power purchase obligations	656.4	351.4	305.0	-	-
Asset retirement obligations	249.9	-	-	-	249.9
Total	$ 2,657.1	$ 423.9	$ 454.9	$ 399.7	$ 1,378.6

We have no capital lease obligations, no purchase obligations, no other long-term liabilities, and no construction obligations that are considered contractual obligations.

We expect to fund these obligations with cash flow from operations and the issuances of additional long-term indebtedness.

Long-Term Indebtedness

At December 31, 2006, nearly all of our long-term indebtedness was issued under the Indenture. This indebtedness includes bonds issued to the public and bonds issued to local governmental authorities in consideration for loans to us of the proceeds of tax-exempt offerings of indebtedness by those governmental authorities. Long-term indebtedness includes both the principal of and interest on long-term indebtedness, long-term indebtedness due within one year and unamortized discounts and premiums relating to long-term indebtedness.

Operating Lease Obligations

In 1996, we entered into two separate long-term lease transactions of our undivided interests in each of Clover Unit 1 and Clover Unit 2. See "Properties—Clover" in Item 2. Our obligations described above relate to a portion of our obligations under these leases, including periodic basic rent. We fund substantially all of our payment of these obligations through the application of the proceeds of investments we purchased at the time we entered into the leases. The investments are rated "AAA" by Standard & Poor's Ratings Services ("S&P") and "Aaa" by Moody's Investors Service ("Moody's"). Operating lease obligations includes (1) periodic basic rent obligations under the two separate long-term lease transactions which will not be satisfied by the payment undertakers under the payment undertaking agreements, and (2) the purchase option prices at the end of the term of the Leasebacks.

Power Purchase Obligations

As part of our power supply strategy, we entered into a number of agreements for the purchase of capacity and energy in order to meet our member distribution cooperatives' requirements. See "Business—Power Supply Resources—Power Purchase Contracts " in Item 1. Some of these power purchase agreements contain firm capacity and minimum energy purchase obligations.

Asset Retirement Obligations

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" which requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. A significant portion of our asset retirement obligations relates to the future decommissioning of North Anna by 2059.

Significant Contingent Obligations

In addition to these existing contractual obligations, we have significant contingent obligations. These obligations primarily relate to our power purchase arrangements and leases of our interest in Clover. See "Properties—Clover" in Item 2.

To facilitate the ability of TEC, which is consolidated in our financial statements as of December 31, 2004, to sell power in the market, we have agreed to guarantee up to a maximum of $60.0 million of TEC's delivery and payment obligations associated with its energy trades if requested. See "Business—TEC" in Item 1. Our agreement to guarantee these obligations continues in effect until we elect to terminate it by providing at least 30 days prior written notice of termination or until all amounts owed to us by TEC have been paid. Our guarantee of TEC's obligations will enable it to maintain sufficient credit support to meet its delivery and payment obligations associated with its energy trades. At December 31, 2006, we had issued guarantees for up to $11.0 million of TEC's obligations and $0.2 million of such obligations were outstanding.

In limited circumstances, we have obligations to provide credit support if our obligations issued under the Indenture are rated below specified thresholds by S&P and Moody's. These circumstances relate to our lease and leaseback of our undivided interest in Clover Unit 1 and some of our purchases of power in the market.

In connection with the lease and leaseback of our undivided interest in Clover Unit 1, we agreed to deliver a letter of credit to the institutional investor party to the lease within 90 days after our obligations under the Indenture are either rated below "A-" by S&P or "Baa2" by Moody's, or if such obligations are placed on negative credit watch by either S&P or Moody's while rated "A-" by S&P or "Baa2" by Moody's, respectively. If our ratings had been below this minimum rating at December 31, 2006, the amount of the letter of credit we would have been required to provide was $53.8 million. The amount of any letter of credit we are required to deliver in connection with the lease decreases over time to zero by December 18, 2018.

In addition, like many other utilities, we purchase power in the market pursuant to a form master power purchase and sale agreement ("EEI Form Contract") prepared by the Edison Electric Institute, an association of U.S. investor-owned electric utilities and industry affiliates. The EEI Form Contract is intended to standardize the terms and conditions of purchases of power in the market and consequently foster trading among utilities. Under the terms of the EEI Form Contract, a utility may agree to provide collateral under certain circumstances. Under the terms of our EEI Form Contracts, the collateral we may be required to post is normally a function of the collateral thresholds we negotiate with a counterparty relative to a range of credit ratings as well as the value of our transaction(s) under the EEI Form Contract with a respective counterparty. At December 31, 2006, we had $23.6 million of collateral on deposit with counterparties pursuant to the EEI Form Contracts we have in place. Typically, collateral thresholds under our EEI Form Contracts are zero once an entity is rated below investment grade by S&P or Moody's (i.e., "BBB-" or "Baa3"). We are also party to two other power purchase agreements with credit provisions similar to those in our EEI Form Contracts. At December 31, 2006, if the credit ratings referenced in our EEI form contracts or our two other power purchase agreements fell below investment grade we estimate we would have been obligated to post approximately $67.0 million of collateral with our counterparties, which is in addition to the $23.6 million referenced above. This calculation is based on energy prices on December 31, 2006 and delivered power for which we have not yet paid. Depending on the difference between the price of power under the contracts and the price of power in the market at the time of the calculation, this amount could increase or decrease.

Additionally, in accordance with the credit policy of PJM, PJM subjects each applicant, participant and member of PJM to a complete credit evaluation to determine its creditworthiness, and whether it must provide any collateral to support its obligations in connection with its PJM transactions. A material change in our financial condition, including the downgrading of our credit rating by any rating agency, could cause PJM to re-evaluate our creditworthiness and require that we provide collateral. As of December 31, 2006, if PJM determined that we needed to provide collateral to support our obligations, PJM could have asked us to provide up to approximately $16.9 million of collateral.

Finally, several of the power purchase agreements we utilize to satisfy our member distribution cooperatives' capacity and energy requirements obligate us to purchase capacity or energy or both beyond specified minimum amounts based on our requirements. See "Business—Power Supply Resources—Power Purchase Contracts" in Item 1.

Off-Balance Sheet Arrangements

In 1996, we entered into two lease transactions relating to our 50% undivided ownership interest in Clover. See "Properties—Clover" in Item 2. One lease relates to our undivided interest in Clover Unit 1 and the other relates to our undivided interest in Clover Unit 2 and, in each case, the common facilities. In both transactions, we leased our undivided interests in the facilities to an owner trust for the benefit of an investor for the full productive life of Unit 1 and Unit 2 in exchange for one-time rental payments at the beginning of the leases of $315.0 million and $320.0 million, respectively. Immediately after the leases to the owner trusts, we leased the units back for terms of 21.8 years and 23.4 years, respectively, and agreed to make periodic rental payments to the owner trusts.

We used a portion of the one-time rental payments we received in each transaction to enter into payment undertaking agreements and to purchase investments, which provide for substantially all of:

- our periodic basic rent payments under the leasebacks; and

- the fixed purchase price of the interests in the units at the end of the terms of the leasebacks if we exercise our option to purchase the interests of the owner trusts in the units at that time.

The payment undertaking agreements and investments are issued or insured by entities, which have claims paying abilities or senior debt obligations which are rated "AAA" by S&P and "Aaa" by Moody's. After entering into the payment undertaking agreements, making the investments and paying transaction costs, we had $23.7 million and $39.3 million, respectively, remaining of the one-time rental payments in the Unit 1 and Unit 2 transactions. As a result, following completion of the transactions, we retained possession and our initial entitlement to the output of the units, and we had funds of $63.0 million remaining.

Both leasebacks require us to make periodic basic rental payments. For 2006, our statement of cash flow reflects payments we made of basic rent to the Unit 1 and Unit 2 owner trusts of $0.9 million and $1.9 million, respectively. Of these payments, $0.6 million and $1.9 million, respectively, were funded through distributions from the investments made with lease proceeds. In addition to these amounts, approximately $7.8 million and $17.5 million of additional basic rent was required under the Unit 1 and Unit 2 leases, respectively, in 2006. These additional amounts of basic rent were paid by third parties, "payment undertakers," under payment undertaking agreements. As described above, we made a payment to each of the payment undertakers at the inception of the leasebacks in consideration for the payment undertakers agreeing to pay additional amounts of basic rent as they become due. We have no obligation to pay or repay additional amounts to the payment undertaker in the future. Under each of these arrangements, we made a payment to the payment undertaker in return for which the payment undertaker agreed to make payments directly to the lender in the related lease transaction in satisfaction of a portion of our basic rent payment obligation under the leaseback and the owner trust's repayment obligation under the loan to it. At December 31, 2006, both the value of the portion of our lease obligations to be paid by the payment undertaker, as well as the value of our interest in the related payment undertaking agreements, totaled approximately $297.5 million and $242.0 million for Unit 1 and Unit 2, respectively. Our financial statements do not reflect the payment undertaking agreements, the payments made by the payment undertaker or the payment of this portion of basic rent. We remain liable for all rental payments under the leasebacks if the payment undertaker fails to make such payments, although the owner trusts have agreed to pursue the payment undertakers before pursuing payment from us.

At the end of the term of both leasebacks, we have the option to purchase the owner trust's interest in the applicable unit or arrange for an acceptable third party to enter into a power purchase agreement with the owner trust. If we decide to purchase the owner trust's interest in a unit, we must pay the applicable owner trust a fixed purchase price of $430.5 million in the case of Unit 1, and $458.9 million in the case of Unit 2. Payments under the payment undertaking agreements will fund a substantial portion of these payments. Substantially all of the remainder of these payments will be funded by the investments we made at the inception of the leaseback. If we do not elect to purchase the owner trust's interest in either unit, Virginia Power has an option to purchase that interest. If Virginia Power elects to purchase the interest but fails to pay the purchase price when due, we are obligated to make that payment, with interest, within 30 days.

If we elect not to purchase the owner trust's interest in either unit, we can arrange for a third party to purchase the applicable owner trust's output of the unit at prices which will preserve each owner trust's net economic return as if we had purchased the related unit at the purchase option price. To be an eligible power purchaser, the third party must have, among other things, a net worth of at least $500 million and minimum specified credit ratings or other acceptable credit enhancement. We would assist in transmitting power to the third party by entering into a transmission and interconnection agreement with the owner trust. We also would be obligated to assist the owner trust in arranging new financing for the lease debt which remains outstanding at the expiration of the leasebacks. We would not be obligated, however, to provide this financing. Under the leaseback for Unit 1, however, if alternate financing is not available or we otherwise fail to satisfy the conditions to arrange for a new third party purchaser, we must either exercise our purchase option or make a termination payment to the owner trust. Under the Unit 1 lease, we also must provide management services to the owner trust if power is being sold to the third party.

In the Unit 1 lease, a third option at the end of the term of the leaseback exists. We may pay to the owner trust an amount equal to the difference between a specified termination amount and the fair market value of its interest in Unit 1 and return possession of the interest in the unit back to the owner trust. The amount we are obligated to pay cannot exceed the specified termination amount minus 20% of the fair market value of the owner trust's interest in the unit at the time the lease was entered into in 1996 or be less than the amount of the owner trust's debt to its lenders at the expiration of the leaseback. If we do not purchase the interest and the owner trust requests, we are obligated to use our best efforts to sell the owner trust's interest in the unit at the end of the leaseback. Any sale proceeds would be credited against the payment we are obligated to make to the owner trust. If we are not able to sell the interest by the end of the leaseback, we must pay the owner trust the full amount of the required payment but we are entitled to be reimbursed out of the proceeds of the sale in excess of 20% of the value of the owner trust's interest at the time the lease was entered into in 1996, plus interest, if the facility is sold within the following 36 months.

In connection with the lease relating to Unit 1, we agreed to deliver a letter of credit to the institutional investor party in the lease in some instances. See "—Significant Contingent Obligations" above.

Tax Increase Prevention and Reconciliation Act of 2005

On May 17, 2006, President Bush signed into law an act entitled the "Tax Increase Prevention and Reconciliation Act of 2005" (the "2005 Tax Act"). Among other provisions, the 2005 Tax Act imposes an excise tax on certain types of leasing transactions entered into by tax-exempt entities. At this time, it is not clear whether the excise tax imposed by the 2005 Tax Act is applicable to our lease transactions. We are continuing to evaluate this legislation and the impact on us; however, specific guidance has not yet been made available. We have revised our estimate of the potential impact and have determined that we do not need to record a liability based upon the currently available information. We have determined that our potential liability for 2006 could range from zero to approximately $1.2 million and that zero represents our best estimate at this time. However, once further guidance is issued, our potential liability under the 2005 Tax Act may change.

Future Issues

Reliance on Market Purchases of Energy

While the combustion turbine facilities provide most of our capacity requirements above those met by Clover and North Anna, they do not satisfy a significant portion of our energy requirements. Combustion turbine facilities are most economical to operate when the market price of energy is relatively high compared to the variable costs to operate these facilities. By operating the combustion turbine facilities during those times, we reduce our exposure to market energy price volatility risk but use the market to supply energy during other times.

Because we have and will rely heavily on market purchases of energy, we have taken two primary steps to reduce our exposure to future price fluctuations in the energy market. We have secured, through market purchases or energy contracts, a substantial portion of our energy requirements not supplied by our generating facilities or the combustion turbine facilities through the end of 2008. We plan to continue purchasing energy for significant periods into the future by utilizing a combination of long-term and short-term physically-delivered forward fixed price contracts and option contracts for the purchase of energy, as well as spot market purchases. In addition, we plan to use similar efforts to manage our exposure to market changes in the price of fuel, especially changes in the price of natural gas. Second, we have engaged ACES Power Marketing LLC ("APM"), an energy trading and risk management company, to assist us in executing trades to purchase energy, developing a strategy of when to operate the combustion turbine facilities or purchase energy, modeling our power requirements, and analyzing our power purchase contracts and credit risks of counterparties. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A. We continue to review our power supply resource options and future requirements. As we have done in the past, we expect to adjust our portfolio of power supply resources to reflect our projected power requirements and changes in the market.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The operation of our business exposes us to several common market risks, including changes in interest rates, equity prices and market prices for power and fuel. We are exposed to market price risk by purchasing power and natural gas in the market to supply a portion of the power requirements of our member distribution cooperatives. In addition, we are exposed to a limited amount of interest rate and equity price risk.

Market Price Risk

We are exposed to market price risk by purchasing power in the market to supply the power requirements of our member distribution cooperatives in excess of our entitlement to the output of our generating facilities. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Future Issues—Reliance on Market Purchases of Energy" in Item 7. In addition, the purchase of fuel to operate our generating facilities also exposes us to market price risk.

As an example of our level of exposure to market price risk, a 10% increase in the purchase price of our unhedged power, natural gas and coal purchases is estimated to have increased these expenses by approximately $10.5 million or 1.8% of total energy-related operating expenses in 2006. Conversely, a 10% decrease in these purchase prices is estimated to have decreased expenses by approximately the same amount. This calculation assumes generation and purchases consistent with historical performance and applies the 10% increase or decrease only to purchases not hedged at the beginning of 2006.

The fair value of the hedging instruments we use to mitigate market price risk is impacted by changes in market prices. At December 31, 2006, we estimate that the fair value of our purchase power agreements and forward purchases of energy and natural gas is between $800 million and $900 million. Approximately 75% of the fair value of this portfolio is estimable using observable market prices. The remaining 25% of the fair value of this portfolio is related to less liquid products and the fair values of these products are not directly estimable using observable market prices. In the absence of observable market prices, the valuation of the 25% of this portfolio that relates to less liquid products involves management judgment, the use of estimates, and the underlying assumptions in our portfolio model, which we have developed with the assistance of APM. As a result, changes in estimates and underlying assumptions or use of alternate valuation methods could affect the estimated fair value of this portfolio. As an example of our portfolio's exposure to market price risk, a 10% increase in the price of the commodities hedged by the portion of this portfolio with observable market prices is estimated to have increased the fair value of this portion of the portfolio by $64.3 million at December 31, 2006. Conversely, a 10% decrease in the price of the commodities hedged by the same portion of this portfolio is estimated to have decreased the fair value of this portion of the portfolio by $64.3 million. To the extent all or portions of our portfolio are liquidated at above or below our original cost, these gains or losses are factored into the energy costs billed to our members pursuant to our formulary rate.

The hedging instruments we use to mitigate market price risk generally include collateral requirements that require us to deposit funds or post letters of credit with counterparties when a counterparty's credit exposure to us is in excess of agreed upon credit limits. When commodity prices decrease to levels below the levels where we have hedged future costs, we may be required to use a material portion of our cash or liquidity facilities to cover these collateral requirements. For example, at December 31, 2006, we had $48.9 million of collateral on deposit with our counterparties and a further 10% decrease in the price of the commodities hedged by our portfolio would have required us to post additional collateral of approximately $21.1 million at December 31, 2006.

Through our relationship with APM, we have formulated policies and procedures to manage the risks associated with these market price fluctuations. We use various commodity instruments, such as futures, forwards and options, to reduce our risk exposure. APM assists us in managing our market price risks by:

- maintaining a portfolio model that identifies our power producing resources (including our power purchase contract positions and generating capacity, and fuel supply, transportation and storage arrangements) and analyzing the optimal use of these resources in light of costs and market risks associated with using these resources;

- modeling our power obligations and assisting us with analyzing alternatives to meet our member distribution cooperatives' power requirements;
- selling power as our agent and the agent of TEC; and
- executing hedge trades to stabilize the cost of fuel requirements, primarily natural gas, used to operate our combustion turbine facilities and to limit our exposure under power purchase contracts with variable rates based on natural gas prices.

We also are subject to market price risk relating to purchases of fuel for North Anna and Clover. We manage these risks indirectly through our participation in the management arrangements for these facilities. Virginia Power, as operator of these facilities, has the direct authority and responsibility to procure nuclear fuel and coal for North Anna and Clover, respectively.

We understand that Virginia Power's procurement strategy for nuclear fuel includes both spot purchases and long-term contracts and is regularly reviewed by various fuel procurement personnel and Virginia Power management. Virginia Power regularly evaluates worldwide market conditions to ensure a range of supply options at reasonable prices. See "Business—Fuel Supply—Nuclear" in Item 1.

Virginia Power has advised us that its coal procurement policy for the Clover facility is to secure the bulk of its requirements under long-term contracts, with specific contract target percentages fluctuating, based on prevailing market conditions. The majority of the coal supplied to Clover is delivered under long-term contracts. Generally, on a quarterly basis, Virginia Power has advised us that it evaluates the specific terms offered by various coal suppliers to determine the optimal mix of long-term and spot market purchases, and subsequently enters purchase agreements to accomplish the desired mix. See "Business—Fuel Supply—Coal" in Item 1.

Interest Rate Risk and Equity Price Risk

In 2006, all of our outstanding long-term indebtedness accrued interest at fixed rates, except for a $6.8 million promissory note owed to Virginia Power which relates to the loan to us of a portion of the proceeds of a tax-exempt debt financing. A 2% rise in interest rates would result in our paying Virginia Power approximately $135,000 of additional interest per year.

We also have $180.0 million of committed available lines of credit and $100.0 million available under revolving credit agreements. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources." Any amounts we borrow under these facilities will accrue interest at a variable rate. During 2006, no amounts were outstanding under any of these facilities.

At December 31, 2006, $20.0 million of our cash and cash equivalents was invested primarily in fixed-income securities. Due to the short-term nature of these investments, an increase or decrease in interest rates is unlikely to materially increase or decrease the income generated by our cash and cash equivalents.

We accrue decommissioning costs over the expected service life of North Anna and have made periodic deposits to a trust fund so that the fund balance will cover the estimated cost to decommission North Anna at the time of decommissioning. At December 31, 2006, $33.4 million of these funds were invested in fixed-income securities and $58.2 million of these funds were invested in equity securities. The value of these equity and fixed income securities will be impacted by changes in interest rates and price fluctuations in equity markets. To minimize adverse changes in the aggregate value of the trust fund, we actively monitor our portfolio by measuring the performance of our investments against market indexes and by maintaining and reviewing established target allocation percentages of assets in our trust to various investment options. We believe the trust fund's exposure to changes in interest rates and price fluctuations in equity markets will not have a material impact on our financial results.

Credit Risk

Credit risk is defined as the potential loss that we could incur as a result of non-payment or non-performance by a counterparty. We attempt to measure and monitor the amount of our credit risk principally in order to maintain an acceptable level of credit risk. We are exposed to credit risk through our power and fuel purchases and sales.

Our internal risk management committee has the overall responsibility to review and manage our credit risk and does so on a regular basis. We have adopted a Credit Risk Policy that establishes the basis for determining counterparty credit standards and processes to determine credit limits. Through our relationship with APM, we obtain information and assistance to enable us to manage our credit risk. If required by our credit standards and limits, we require counterparties to provide collateral in the form of letters of credit, cash, parent guarantees or other collateral in the future upon the occurrence of specified events. Our risk management committee monitors our credit exposure on a regular basis. At December 31, 2006, we did not hold collateral related to power and fuel purchases.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONSOLIDATED FINANCIAL STATEMENTS
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Report of Independent Registered Public Accounting Firm

To The Board of Directors
Old Dominion Electric Cooperative

We have audited the accompanying consolidated balance sheets of Old Dominion Electric Cooperative as of December 31, 2006 and 2005, and the related consolidated statements of revenues, expenses and patronage capital, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Cooperative's internal control over financial reporting. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Old Dominion Electric Cooperative at December 31, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements the Cooperative changed its method of accounting for variable interest entities effective December 31, 2004, to comply with the accounting provisions of Financial Accounting Standard Interpretation No. 46R.

Richmond, Virginia
March 14, 2007

OLD DOMINION ELECTRIC COOPERATIVE
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2006 AND 2005

	2006	2005
	(in thousands)	
ASSETS:		
Electric Plant:		
In service	$ 1,527,672	$ 1,519,578
Less accumulated depreciation	(509,306)	(470,735)
	1,018,366	1,048,843
Nuclear fuel, at amortized cost	8,381	9,018
Construction work in progress	20,342	16,365
Net Electric Plant	1,047,089	1,074,226
Investments:		
Nuclear decommissioning trust	91,050	79,464
Lease deposits	171,585	163,156
Other	24,321	12,193
Total Investments	286,956	254,813
Current Assets:		
Cash and cash equivalents	52,018	98,633
Deposits	-	24,686
Accounts receivable	4,071	25,242
Accounts receivable - deposits	23,600	-
Accounts receivable - members	94,136	80,569
Fuel, materials and supplies	30,585	25,669
Deferred energy	14,914	21,328
Prepayments	4,035	3,304
Total Current Assets	223,359	279,431
Deferred Charges:		
Regulatory assets	49,738	43,753
Other	20,267	60,143
Total Deferred Charges	70,005	103,896
Total Assets	$ 1,627,409	$ 1,712,366
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 293,077	$ 271,833
Non-controlling interest	10,993	25,062
Long-term debt	813,264	832,980
Total Capitalization	1,117,334	1,129,875
Current Liabilities:		
Long-term debt due within one year	22,917	22,917
Accounts payable	87,844	89,854
Accounts payable - members	48,220	64,110
Accounts payable - deposits	-	24,686
Accrued expenses	35,767	33,740
Total Current Liabilities	194,748	235,307
Deferred Credits and Other Liabilities:		
Asset retirement obligations	55,812	48,810
Obligations under long-term leases	174,205	166,043
Regulatory liabilities	51,497	95,271
Other	33,813	37,060
Total Deferred Credits and Other Liabilities	315,327	347,184
Commitments and Contingencies	-	-
Total Capitalization and Liabilities	$ 1,627,409	$ 1,712,366

The accompanying notes are an integral part of the consolidated financial statements.

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED STATEMENTS OF REVENUES, EXPENSES AND PATRONAGE CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

	2006	2005	2004
		(in thousands)	
Operating Revenues	$ 817,515	$ 737,679	$ 588,451
Operating Expenses:			
Fuel	154,931	143,332	90,635
Purchased power	464,047	434,557	314,763
Deferred energy	6,414	(26,135)	(8,775)
Operations and maintenance	35,551	34,221	40,595
Administrative and general	32,502	34,523	28,800
Depreciation, amortization and decommissioning	38,393	38,556	32,759
Amortization of regulatory asset/(liability), net	2,701	1,909	20,543
Accretion of asset retirement obligations	2,783	2,496	2,251
Taxes other than income taxes	6,732	6,024	5,265
Total Operating Expenses	744,054	669,483	526,836
Operating Margin	73,461	68,196	61,615
Other (Expense)/Income, net	(45)	(157)	129
Investment Income	10,591	6,620	2,896
Interest Charges, net	(60,949)	(60,347)	(52,506)
Net Margin before income taxes and non-controlling interest	23,058	14,312	12,134
Income taxes	(726)	(881)	-
Non-controlling interest	(1,088)	(1,322)	-
Net Margin	21,244	12,109	12,134
Patronage Capital - Beginning of Year	271,833	259,724	247,590
Patronage Capital - End of Year	$ 293,077	$ 271,833	$ 259,724

The accompanying notes are an integral part of the consolidated financial statements.

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

	2006	2005 (in thousands)	2004
Net Margin	$ 21,244	$ 12,109	$ 12,134
Other Comprehensive Income:			
Unrealized (loss)/gain on derivative contracts[1]	(15,157)	15,592	-
Other comprehensive income before non-controlling interest	6,087	27,701	12,134
Less: Non-controlling interest in comprehensive income	15,157	(15,592)	-
Comprehensive Income	$ 21,244	$ 12,109	$ 12,134

The accompanying notes are an integral part of the consolidated financial statements.

[1] The tax effect relates to the consolidation of TEC Trading, Inc.'s, a taxable entity, results of operations beginning in 2005. Unrealized (loss)/gain on derivative contracts net of tax benefit of $9.7 million for 2006 and net of tax expense of $10.0 million for 2005. There was no tax effect in 2004.

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED STATEMENTS OF CASH FLOW
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

	2006	2005	2004
		(in thousands)	
Operating Activities:			
Net Margin	$ 21,244	$ 12,109	$ 12,134
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and decommissioning	38,393	38,556	32,759
Other noncash charges	16,192	11,555	10,779
Non-controlling interest	1,088	1,322	-
Amortization of lease obligations	10,976	10,368	9,964
Interest on lease deposits	(10,647)	(9,953)	(9,542)
Change in current assets	3,043	(55,611)	(18,111)
Change in deferred energy	6,414	(26,135)	(8,775)
Change in current liabilities	(30,869)	89,442	(39,952)
Change in regulatory assets and liabilities	(55,833)	63,558	15,134
Change in deferred charges and credits	14,546	(12,652)	(3,446)
Net Cash Provided by Operating Activities	14,547	122,559	944
Financing Activities:			
Payment of long-term debt	(22,917)	(22,917)	-
Obligations under long-term leases	(596)	(521)	(529)
Net Cash (Used for) Financing Activities	(23,513)	(23,438)	(529)
Investing Activities:			
Purchases of available for sale securities	(112,650)	(101,085)	(10,500)
Proceeds from sale of available for sale securities	100,325	107,540	53,000
Increase in other investments	(5,316)	(4,403)	(3,234)
Consolidation of TEC Trading, Inc.	-	-	2,488
Electric plant additions	(20,008)	(20,104)	(56,363)
Net Cash (Used for) Investing Activities	(37,649)	(18,052)	(14,609)
Net Change in Cash and Cash Equivalents	(46,615)	81,069	(14,194)
Cash and Cash Equivalents-Beginning of Year	98,633	17,564	31,758
Cash and Cash Equivalents-End of Year	$ 52,018	$ 98,633	$ 17,564

The accompanying notes are an integral part of the consolidated financial statements.

OLD DOMINION ELECTRIC COOPERATIVE
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—Summary of Significant Accounting Policies

General

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative ("ODEC" or "we" or "our"), its subsidiaries and TEC Trading, Inc. ("TEC"). In accordance with Financial Accounting Standards Board ("FASB") Interpretation No. 46R, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51" (the "Interpretation"), TEC, is considered a variable interest entity for which we are the primary beneficiary and has been consolidated as of December 31, 2004. We have eliminated all intercompany balances and transactions in consolidation. Our non-controlling, 50% or less, ownership interest in other entities is recorded using the equity method of accounting.

We are a not-for-profit wholesale power supply cooperative, incorporated under the laws of the Commonwealth of Virginia in 1948. We have two classes of members. Our Class A members are twelve customer-owned electric distribution cooperatives engaged in the retail sale of power to member consumers located in Virginia, Delaware, Maryland, and parts of West Virginia. Our sole Class B member is TEC, a taxable corporation owned by our member distribution cooperatives. Our board of directors is composed of two representatives from each of the member distribution cooperatives and one representative from TEC. Our rates are not regulated by the respective states' public service commissions, but are set periodically by a formula that was accepted for filing by the Federal Energy Regulatory Commission ("FERC") on December 23, 2003. An amendment to the formula was accepted for filing by FERC on February 19, 2005, subject to the outcome of other pending ODEC FERC proceedings.

We comply with the Uniform System of Accounts prescribed by FERC. In conformity with accounting principles generally accepted in the United States ("GAAP"), the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes.

In accordance with Financial Accounting Standards Board Interpretation No. 46R, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51" (the "Interpretation"), TEC was considered a variable interest entity for which ODEC was the primary beneficiary and has been consolidated as of December 31, 2004. Because TEC was not consolidated until December 31, 2004, TEC's revenues and expenses for 2004 are not included in ODEC's consolidated statements of revenues, expenses and patronage capital and consolidated statements of cash flow for 2004. Beginning in 2005, the income statement of TEC is consolidated and the inter-company revenues and expenses are eliminated in consolidation. The balance sheet of TEC has been consolidated into the financial statements of ODEC and all inter-company balances have been eliminated in the consolidation. Because TEC is 100% owned by ODEC's twelve member distribution cooperatives, its equity is presented as a non-controlling interest in ODEC's consolidated financial statements.

TEC was initially capitalized by ODEC in 2001 with a $7.5 million cash investment in exchange for all of its capital stock. ODEC then distributed all of TEC's stock as a patronage capital distribution to its member distribution cooperatives. TEC was formed for the primary purpose of purchasing from us, to sell in the market, energy that is not needed to meet the actual needs of ODEC's member distribution cooperatives, acquiring natural gas and forward purchase contracts to hedge the price of natural gas to supply our combustion turbine facilities, and to take advantage of other power-related trading opportunities in the market which will help lower our member distribution cooperatives' costs. TEC does not engage in speculative trading. ODEC first became the primary beneficiary upon the formation of TEC in 2001. As both ODEC and TEC were under common control at the date TEC was formed and the date ODEC became the primary beneficiary, the initial measurement of TEC's assets and liabilities was at their carrying amounts.

The preparation of our consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported therein. Actual results could differ from those estimates.

Electric Plant

Electric plant is stated at original cost when first placed in service. Such cost includes contract work, direct labor and materials, allocable overhead, an allowance for borrowed funds used during construction and asset retirement costs. Upon the partial sale or retirement of plant assets, the original asset cost and current disposal costs less sale proceeds, if any, are charged or credited to accumulated depreciation. In accordance with industry practice, no profit or loss is recognized in connection with normal sales and retirements of property units.

Maintenance and repair costs are expensed as incurred. Replacements and renewals of items considered to be units of property are capitalized to the property accounts.

Depreciation

Beginning January 1, 2005, we conducted a depreciation study and updated our depreciation rates. Depreciation rates are as follows:

Generating Facility	Depreciation Rates		
	2006	2005	2004
	(in percents)		
Clover	1.8 %	1.8 %	2.1 %
North Anna	2.9	3.2	2.1
Louisa	3.5	3.6	3.4
Marsh Run	3.5	3.6	3.6
Rock Springs	3.8	3.8	3.6

Nuclear Fuel

Nuclear fuel is amortized on a unit of production basis sufficient to fully amortize the cost of fuel over the estimated service life and is recorded in fuel expense.

In accordance with the Nuclear Waste Policy Act of 1982, the Department of Energy ("DOE") is required to provide for the permanent disposal of spent nuclear fuel produced by nuclear facilities, such as the North Anna Nuclear Power Station ("North Anna") in which we have an 11.6% ownership interest, in accordance with contracts executed with the Department of Energy ("DOE"). However, since the DOE did not begin accepting spent fuel in 1998 as specified in its contracts, Virginia Electric & Power Company ("Virginia Power") is providing on-site spent nuclear fuel storage at the North Anna facility. These facilities are expected to be adequate until the DOE begins accepting the spent nuclear fuel. Virginia Power will continue to safely manage its spent nuclear fuel until the DOE begins accepting the spent nuclear fuel. In January 2004, Virginia Power filed a lawsuit seeking recovery damages for breech of the standard contract due to the DOE's delay in accepting spent nuclear fuel for North Anna.

Fuel, Materials and Supplies

Fuel, materials and supplies is primarily comprised of spare parts for our generating assets, which are recorded at lower of cost or market, and fuel, which consists primarily of coal and #2 fuel oil, which is recorded at average cost.

Allowance for Borrowed Funds Used During Construction

Allowance for borrowed funds used during construction is defined as the net cost of borrowed funds used for construction purposes during the construction period and a reasonable rate on other funds when so used. We capitalize interest on borrowings for significant construction projects. Interest capitalized in 2006, 2005, and 2004, was $0.3 million, $0.2 million, and $8.2 million, respectively.

Income Taxes

As a not-for-profit electric cooperative, we are currently exempt from federal income taxation under Section 501(c)(12) of the Internal Revenue Code of 1986, as amended, and we intend to continue to operate in this manner. Based on our assessment and evaluations of relevant authority, we believe we could sustain treatment as a tax-exempt utility in the event of a challenge of our tax status. Accordingly, no provisions for income taxes has been recorded based on ODEC's operations in the accompanying consolidated financial statements.

TEC, a taxable corporation, has been consolidated in the accompanying financial statements as of December 31, 2004, and its provision for income taxes was approximately $0.1 million and $0.9 million as of December 31, 2006 and December 31, 2005, respectively.

Operating Revenues

Our operating revenues are derived from sales to our members and non-members. We sell energy to our Class A members pursuant to long-term wholesale power contracts that we maintain with each of our member distribution cooperatives. These wholesale power contracts obligate each member distribution cooperative to pay us for power furnished in accordance with our rates. Power furnished is determined based on month-end meter readings. At December 31, 2006, 2005, and 2004, sales to our member distribution cooperatives were $746.5 million, $657.0 million, and $564.6 million, respectively. See Note 5—Wholesale Power Contracts—to the Consolidated Financial Statements.

We sell excess purchased energy and excess generated energy from our combustion turbine facilities, if any, to our Class B member under FERC market-based rate authority. Beginning January 1, 2005, the income statement of TEC is consolidated and the inter-company revenues and expenses are eliminated in consolidation. Therefore, we reported no sales to TEC beginning in 2005. TEC's sales to third parties are reflected as non-member revenues. Sales to TEC consisted primarily of sales of excess energy that we did not need to meet the actual needs of our member distribution cooperatives. We sold the portion of this energy that could not be utilized by our member distribution cooperatives to TEC for resale into the market, or to non-members. In 2004, sales to TEC were $18.9 million. Excess purchased energy that is not sold to TEC is sold to the PJM Interconnection, LLC ("PJM") under its rates for providing energy imbalance service. Prior to May 1, 2005, excess energy from Clover was sold to Virginia Power. For the years ended December 31, 2006, 2005, and 2004, energy sales to non-members were $71.0 million, $80.7 million, and $4.9 million, respectively.

Regulatory Assets and Liabilities

We account for certain revenues and expenses as a rate-regulated entity in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 which allows certain revenues and expenses to be deferred at the discretion of our board of directors, pursuant to their budgetary and rate setting authority, if it is probable that such amounts will be refunded or recovered through our formulary rate in future years. Regulatory assets represent certain costs that are expected to be recovered from our member distribution cooperatives based on rate action by our board of directors in accordance with our formulary rate. Regulatory liabilities represent certain probable future reductions in revenues associated with amounts that are to be refunded to our member distribution cooperatives based on rate action by our board of directors in accordance with our formulary rate. Certain regulatory assets are included in deferred charges. Certain regulatory liabilities are included in deferred credits and other liabilities. Deferred energy, which can be either a regulatory asset or a regulatory liability, (see Note 1—Deferred Energy—to the Consolidated Financial Statements) is included in current assets or current liabilities. The regulatory assets and liabilities will be recognized as expenses or as a reduction in expenses, concurrent with their recovery through rates.

Debt Issuance Costs

Capitalized costs associated with the issuance of debt totaled $10.4 million and $11.3 million, at December 31, 2006 and 2005, respectively and are included in deferred charges – other. These costs are being amortized using the effective interest method over the life of the respective debt issues, and are included in interest charges, net.

Deferred Credits and Other Liabilities—Other

Deferred credits and other liabilities—other, includes gains on long-term lease transactions (see Note 6—Long-Term Lease Transactions—to the Consolidated Financial Statements), DOE decontamination and decommissioning liability, and liabilities associated with benefit plans for certain executives. Gains on long-term lease transactions totaled $33.7 million and $36.5 million at December 31, 2006 and 2005, respectively. These gains are being amortized into income ratably over the terms of the operating leases as a reduction to depreciation, amortization and decommissioning expense.

Deferred Energy

We use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. Our deferred energy balance represents the net accumulation of any previous under- or over-collection of energy costs. At December 31, 2006 and 2005, we had an under-collected deferred energy balance of $14.9 million and $21.3 million, respectively. Under-collected deferred energy balances are collected from our members in subsequent periods.

Financial Instruments (including Derivatives)

Financial instruments included in the decommissioning fund are classified as available for sale, and accordingly, are carried at fair value. Unrealized gains and losses on investments held in the decommissioning fund are deferred as a regulatory liability or a regulatory asset until realized.

Our investments in marketable securities, which are actively managed, are classified as available for sale and are recorded at fair value. Unrealized gains or losses on these investments, if material, are reflected as a component of other comprehensive income. Investments in debt securities that we have the positive intent and ability to hold to maturity are classified as held to maturity and are recorded at amortized cost. See Note 7—Investments—to the Consolidated Financial Statements. Other investments are recorded at cost, which approximates market value.

We purchase power under both long-term and short-term physically-delivered forward contracts to supply power to our member distribution cooperatives under "all requirements" wholesale power contracts. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of the forward purchase derivative contracts qualify for the normal purchases/normal sales exception under SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities." As a result, these contracts are not recorded at fair value. We record a liability and purchased power expense when the power under the forward contract is delivered.

We also purchase natural gas futures generally for three years or less to hedge the price of natural gas for the operation of our combustion turbine facilities and for use as a basis in determining the price of power in certain forward power purchase agreements. These derivatives do not qualify for the normal purchases/normal sales exception. For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we may elect cash flow hedge accounting in accordance with SFAS No. 133. Accordingly, gains and losses on derivative contracts are deferred into Other Comprehensive Income until the hedged underlying transaction occurs or is no longer likely to occur. For derivative contracts where hedge accounting is not utilized, or for which ineffectiveness exists, we defer all remaining gains and losses on a net basis as a regulatory asset or liability in accordance with SFAS No. 71 "Accounting for Certain Types of Regulation." These amounts are subsequently reclassified as purchased power or fuel expense in our Consolidated Statements of Revenues, Expenses, and Patronage Capital as the power or fuel is delivered and/or the contract settles.

Generally, derivatives are reported on the Consolidated Balance Sheet at fair value. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications. For individual contracts, the use of differing assumptions could have a material effect on the contract's estimated fair value. During 2006, 2005, and 2004, we expensed option premiums totaling $3.0 million, $0.8 million, and $1.4 million, respectively, as purchased power expense.

Hedge ineffectiveness during the years ended December 31, 2006 and 2005, was $0.1 million and $0.2, respectively. There was no hedge ineffectiveness during the year ended December 31, 2004.

Risk Management Policy

We have established an internal Risk Management Committee to monitor the compliance with our established risk management policies.

We are exposed to market risks associated with commodity prices for energy and fuel related to our business operations. Through our relationship with ACES Power Marketing LLC ("APM"), we have formulated policies and procedures to manage the risks associated with these price fluctuations. We manage our exposure to these fluctuations in energy and fuel market prices by entering into forward purchase contracts to hedge the variability of cash flows associated with changes in market prices of energy. We have operating procedures in place to help ensure that proper internal controls are maintained regarding the use of derivatives.

We are also exposed to credit risk in our business operations. We have adopted a Credit Risk Policy that establishes the basis for determining counterparty credit standards and processes to determine credit limits. Our risk management committee monitors credit exposure on a regular basis. Formal counterparty credit reviews are performed at least annually and informal reviews are performed on an ongoing basis. At December 31, 2006, none of our counterparties were required to post collateral for power and fuel purchases and sales. At December 31, 2005, our counterparties for power and fuel purchases and sales had posted $24.7 million in collateral.

Patronage Capital

We are organized and operate as a cooperative. Patronage capital represents our retained net margins, which have been allocated to our members based upon their respective power purchases in accordance with our bylaws. Any distributions are subject to the discretion of our board of directors and the restrictions contained in the Indenture of Mortgage and Deed of Trust, dated as of May 1, 1992, between ODEC and Crestar Bank (predecessor to SunTrust Bank), as trustee (as supplemented by seventeen supplemental indentures thereto and hereinafter referred to as the "Indenture").

Concentrations of Credit Risk

Financial instruments that potentially subject us to concentrations of credit risk consist of cash equivalents, investments, and receivables arising from sales to our members and non-members. We place our temporary cash investments with high credit quality financial institutions and invest in debt securities with high credit standards as required by our board of directors. Cash and cash equivalents balances may exceed FDIC insurance limits on occasion. Concentrations of credit risk with respect to receivables arising from sales to our member distribution cooperatives are limited due to the large member consumer base that represents our member distribution cooperatives' accounts receivable. Receivables from our member distribution cooperatives at December 31, 2006 and 2005, were $94.1 million and $80.6 million, respectively.

Cash Equivalents

For purposes of our Consolidated Statements of Cash Flow, we consider all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

New Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109" ("FIN 48"). This interpretation requires that income tax positions recognized in an entity's tax returns have a more-likely-than-not chance of being sustained prior to recording the related tax benefit in the financial statements. Tax benefits would be derecognized if information became available which indicated that it was more-likely-than-not that the position would not be sustained. We will adopt this interpretation in the first quarter of fiscal 2007. We have substantially completed our analysis of FIN 48 and we do not expect it to have a material impact on our financial statements.

In September 2006, the FASB issued Statement No. 157, "Fair Value Measurements" ("SFAS No. 157"). SFAS No. 157 clarifies that the term fair value is intended to mean a market-based measure, not an entity-specific measure and gives the highest priority to quoted prices in active markets in determining fair value. SFAS No. 157 requires disclosures about the extent to which companies measure assets and liabilities at fair value, the methods and assumptions used to measure fair value, and the effect of fair value measures on earnings. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact that SFAS No. 157 may have on our financial statements.

Reclassifications

Certain reclassifications have been made to the prior years' consolidated financial statements to conform to the current year's presentation.

NOTE 2—Electric Plant

Our net electric plant is comprised of the following for 2006:

	Clover	North Anna	Combustion Turbines	Other	Total
	(in thousands, except percentages)				
Ownership interest	50%	11.6%	100%	100%	
Electric plant in service	$654,128	$281,023	$ 574,885	$ 17,636	$ 1,527,672
Accumulated depreciation	(300,008)	(140,533)	(61,866)	(6,899)	(509,306)
Nuclear fuel	-	49,258	-	-	49,258
Accumulated amortization of nuclear fuel	-	(40,877)	-	-	(40,877)
Construction work in progress	3,811	16,346	50	135	20,342
	$357,931	$165,217	$ 513,069	$ 10,872	$ 1,047,089

Our net electric plant was comprised of the following for 2005:

	Clover	North Anna	Combustion Turbines	Other	Total
		(in thousands, except percentages)			
Ownership interest	50%	11.6%	100%	100%	
Electric plant in service	$655,265	$272,225	$ 575,386	$ 16,702	$ 1,519,578
Accumulated depreciation	(289,944)	(132,698)	(42,057)	(6,036)	(470,735)
Nuclear fuel	-	48,218	-	-	48,218
Accumulated amortization of nuclear fuel	-	(39,200)	-	-	(39,200)
Construction work in progress	415	15,895	-	55	16,365
	$365,736	$164,440	$ 533,329	$ 10,721	$ 1,074,226

Investment in Jointly Owned Generating Facilities

We hold a 50% undivided ownership interest in the Clover Power Station ("Clover"), a two-unit, 860 MW (net capacity entitlement) coal-fired electric generating facility operated by Virginia Power. We are responsible for 50% of all post-construction additions and operating costs associated with Clover, as well as a pro-rata portion of Virginia Power's administrative and general expenses for Clover, and must fund these items. Our portion of assets, liabilities, and operating expenses associated with Clover are included in our consolidated financial statements. At December 31, 2006 and 2005, we had an outstanding accounts payable balance of $1.4 million and $5.1 million, respectively, due to Virginia Power for operation, maintenance, and capital investment at Clover.

We have an 11.6% undivided ownership interest in North Anna, a two-unit, 1,842 MW (net capacity entitlement) nuclear power facility, as well as nuclear fuel and common facilities at the power station, and a portion of spare parts inventory, and other support facilities. North Anna is operated by Virginia Power, which owns the balance of the plant. We are responsible for 11.6% of all post acquisition date additions and operating costs associated with the plant, as well as a pro-rata portion of Virginia Power's administrative and general expenses for North Anna, and must fund these items. Our portion of assets, liabilities, and operating expenses associated with North Anna are included in our consolidated financial statements. At December 31, 2006, we did not have an outstanding accounts payable balance due to Virginia Power for the operation, maintenance, and capital investment at the North Anna facility and at December 31, 2005, we had an outstanding accounts payable balance of $4.2 million related to North Anna.

Projected capital expenditures for Clover for 2007 through 2009 are $1.9 million, $6.3 million and $2.9 million, respectively. Projected capital expenditures for North Anna for 2007 through 2009 are $15.4 million, $15.5 million and $15.0 million, respectively.

Property, Plant & Equipment

We own three combustion turbine facilities that are carried at cost, less accumulated depreciation. We also own distributed generation facilities, which are included in "Other" in the net electric plant table. Projected capital expenditures for our combustion turbine facilities for 2007 through 2009 are $0.5 million, $0.5 million, and $0.5 million, respectively. Projected capital expenditures for our distributed generation facilities and other for 2007 through 2009 are $3.2 million, $0.6 million and $0.6 million, respectively.

NOTE 3— Accounting for Asset Retirement Obligations

We adopted SFAS No. 143 "Accounting for Asset Retirement Obligations" effective January 1, 2003. SFAS No. 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized asset is depreciated over the useful life of the long-lived asset. SFAS

No. 143 requires that any transition adjustment determined at adoption be recognized as a cumulative effect of change in accounting principle.

In the absence of quoted market prices, we determined fair value by using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit adjusted risk free rate. Our estimated liability could change significantly if actual costs vary from assumptions or if governmental regulations change significantly.

Approximately every four years, a new decommissioning study for North Anna is performed. In 2006, we received the new study and adopted it effective January 1, 2006, which resulted in an additional layer related to the asset retirement obligation associated with North Anna. The additional layer resulted in an increase to our asset retirement cost and our asset retirement obligation of $4.2 million.

The following represents changes in our asset retirement obligations for the years ended December 31, 2006 and 2005 (in thousands):

Asset retirement obligations at December 31, 2004	$ 46,295
Additional asset retirement obligations - FIN 47	19
Accretion expense	2,496
Asset retirement obligations at December 31, 2005	$ 48,810
Accretion expense	2,783
Additional asset retirement obligations - new layer	4,219
Asset retirement obligations at December 31, 2006	$ 55,812

The cash flow estimates for North Anna's asset retirement obligations were based upon the 20-year life extension. Given the life extension, the level of decommissioning trust fund currently appears to be adequate to fund North Anna's asset retirement obligations and no additional funding is currently required. Therefore, with the approval by FERC, we ceased collection of decommissioning expense in August 2003. As we are not currently collecting decommissioning expense in our rates, we are deferring as part of our SFAS No. 143 regulatory liability (See Note 8—Regulatory Assets and Liabilities—to the Consolidated Financial Statements) the difference between the earnings on the decommissioning trust fund and the total asset retirement obligation related depreciation and accretion expense for North Anna.

NOTE 4—Power Purchase Agreements

In 2006, 2005, and 2004, our owned generating facilities together furnished approximately 45.2%, 43.3%, and 47.4%, respectively, of our energy requirements. The remaining needs were satisfied through long-term and short-term physically-delivered forward purchase power contracts with other power suppliers and purchases of energy in the spot markets.

Our most significant long-term power purchase arrangements are with Virginia Power, the operator and co-owner of Clover and North Anna. We have an agreement with Virginia Power, which grant us the right, but not the obligation, to purchase energy at a price determined by reference to a specified natural gas index (the Operating and Sales Agreement, or "OPSA"). In addition, we have other contractual arrangements with Virginia Power which permit us to purchase reserve capacity and energy. We intend to purchase our reserve capacity requirements for Clover and North Anna from Virginia Power under these arrangements until either the date on which all facilities at North Anna have been retired or decommissioned or the date we have no interest in North Anna, whichever is earlier.

The purchase price we pay for any reserve energy purchased under these arrangements equals the natural gas-indexed price we pay for intermediate energy under our other agreements with Virginia Power. In addition to

Virginia Power, we have other power purchase contracts with Mid-Atlantic utilities, which provide a small portion of our capacity and energy requirement.

The remainder of our energy requirements are provided by the market. We purchase significant amounts of power in the market through long-term and short-term physically-delivered forward power purchase contracts. We also purchase power in the spot market. This approach to meeting our member distribution cooperatives' energy requirements is not without risks. To mitigate these risks, we attempt to match our energy purchases with our energy needs to reduce our spot market purchases of energy. Additionally, we have developed policies and procedures to manage the risks in the changing business environment. These procedures, developed in cooperation with APM, are designed to strike the appropriate balance between minimizing costs and reducing energy cost volatility. As of December 31, 2005, our counterparties were required to post $24.7 million in deposits in accordance with the terms of our respective master power purchase and sales agreements with them. At December 31, 2006, due to changes in energy prices, we were required to post $23.6 million with our counterparties.

Our purchased power costs for 2006, 2005, and 2004 were $464.0 million, $434.6 million, and $314.8 million, respectively.

Our power purchase agreements contain certain firm capacity and minimum energy requirements. As of December 31, 2006, our minimum purchase commitments under the various agreements, without regard to capacity reductions or cost adjustments, were as follows:

Year Ending December 31,	Firm Capacity Requirements	Minimum Energy Requirements	Total
		(in millions)	
2007	$ 0.9	$ 343.9	$ 344.8
2008	-	191.8	191.8
2009	-	113.2	113.2
	$ 0.9	$ 648.9	$ 649.8

Congestion

Primarily due to transmission import limitations into the Delmarva Peninsula, our net congestion costs for 2006, 2005, and 2004, were approximately $13.4 million, $14.1 million, and $7.0 million, respectively. These costs were incurred under our transmission agreements with PJM when higher cost generation was run due to transmission constraints.

NOTE 5—Wholesale Power Contracts

We have a wholesale power contract with each of our member distribution cooperatives whereby each member distribution cooperative is obligated to purchase substantially all of its power requirements from us through the year 2028 and beyond 2028 unless either party gives the other at least three years notice of termination. Each such contract provides that we shall provide all of the power that the member distribution cooperative requires for the operation of its system, with limited exceptions, to the extent that we have the power and facilities available. Each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract in accordance with rates and charges established by us pursuant to our formulary rate, which has been accepted by the Federal Energy Regulatory Commission ("FERC".) Under the accepted formulary rate, our rates are developed using a rate methodology under which all categories of costs are specifically separated as components of the formula to determine our revenue requirements. The formula is intended to permit collection of revenues, which, together with revenues from all other sources, are equal to all costs and expenses, plus an additional 20% of total interest charges, plus additional equity contributions as approved by our board of directors. It also provides for the periodic adjustment of our rates to recover actual, prudently incurred costs, whether they increase or decrease, without further application to or acceptance by FERC with limited minor exceptions. In accordance with the formula, the board of directors can authorize accelerating the recovery of costs in the establishment of rates.

The formulary rate allows us to recover and refund amounts under our Margin Stabilization Plan. We have a Margin Stabilization Plan that allows us to review our actual capacity-related cost of service and capacity revenues as of year end and adjust revenues from our member distribution cooperatives to meet our financial coverage requirements and accumulate additional equity as approved by our board of directors. We record all adjustments, whether increases or decreases, in the year affected and allocate any adjustments to our member distribution cooperatives based on power sales during that year. We collect these increases from our member distribution cooperatives, or offset decreases against amounts owed by our member distribution cooperatives to us, in the succeeding calendar year. Each quarter we adjust revenues and accounts payable—members or accounts receivable, as appropriate, to reflect that adjustment. In 2006 and 2005, under our Margin Stabilization Plan, we reduced operating revenues by $2.8 million and $13.3 million, respectively, and increased accounts payable—members by the same amounts. There was no adjustment to operating revenues under our Margin Stabilization Plan in 2004. On November 14, 2006, our board approved an additional equity contribution of $9.0 million in accordance with our wholesale power contracts and our formulary rate.

Revenues from the following member distribution cooperatives equaled or exceeded 10% of our total revenues for the past three years:

	Year Ended December 31,		
	2006	2005	2004
		(in millions)	
Northern Virginia Electric Cooperative	$ 214.5	$ 186.5	$ 159.7
Rappahannock Electric Cooperative	163.7	142.0	120.8
Delaware Electric Cooperative	80.0	72.2	61.0

NOTE 6—Long-term Lease Transactions

On March 1, 1996, we entered into a long-term lease transaction with an owner trust for the benefit of an institutional equity investor. Under the terms of the transaction, we entered into a 48.8 year lease of our interest in Clover Unit 1 (valued at $315.0 million) to such owner trust, and simultaneously entered into a 21.8 year lease of the interest back from such owner trust. As a result of the transaction, we recorded a deferred gain of $23.7 million, which is being amortized into income ratably over the 21.8 year operating lease term, as a reduction to operating expenses.

We have provided for substantially all of our periodic basic rent payments under the lease by investing in obligations issued or insured by entities, the claims paying ability or senior debt obligations of which are rated "AAA" by Standard & Poor's Ratings Services ("S&P") and "Aaa" by Moody's Investors Service ("Moody's"). At the end of the term of the leaseback, we have three options: (1) retain possession of the interest in the unit by paying a fixed purchase price to the owner trust, (2) return possession of the interest to the owner trust and arrange for an acceptable third party to enter into a power purchase agreement with the owner trust, or (3) return possession of the interest and pay a termination amount to the owner trust.

On July 31, 1996, we entered into a long-term lease transaction with a business trust created for the benefit of another equity investor. Under the terms of the transaction, we entered into a 63.4 year lease of our interest in Clover Unit 2 (valued at $320.0 million) to such business trust and simultaneously entered into a 23.4 year lease of the interest back from such business trust. As a result of the transaction, we recorded a deferred gain of $39.3 million, which is being amortized into income ratably over the 23.4 year operating lease term, as a reduction to operating expenses.

At December 31, 2006, and December 31, 2005, the unamortized portion of the deferred gains was $33.7 million and $36.5 million, respectively.

As with the Clover Unit 1 lease, the leaseback of Clover Unit 2 contains events of default, which could result in termination of the lease and loss of possession and right to the output of the unit. At the end of the term of the leaseback, we have two options: (1) retain possession of the interest in the unit by paying a fixed purchase price to the owner trust, or (2) return possession of the interest to the owner trust and arrange for an acceptable third party to enter into a power purchase agreement with the owner trust.

Immediately after the leases to the owner trusts, we leased the units back for terms of 21.8 years and 23.4 years, respectively, and agreed to make periodic rental payments to the owner trusts. We used a portion of the one-time rental payments we received in each transaction to enter into payment undertaking agreements and to purchase investments, which provide for substantially all of our periodic basic rent payments under the leasebacks; and the fixed purchase price of the interests in the units at the end of the terms of the leasebacks if we exercise our option to purchase the interests of the owner trusts in the units at that time. At December 31, 2006 and December 31, 2005, the amount of debt considered to be extinguished by in substance defeasance was \$539.5 million and \$519.9 million, respectively.

NOTE 7—Investments

Investments were as follows at December 31, 2006 and 2005:

Description	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(in thousands)		
December 31, 2006				
Available for Sale				
Corporate obligations	$ 20,000	$ -	$ -	$ 20,000
Registered investment companies[1]	33,514	-	(140)	33,374
Common stock	41,703	15,677	-	57,380
Short-term investments	61,034	-	-	61,034
	$ 156,251	$ 15,677	$ (140)	$ 171,788
Held to Maturity				
U.S. Government obligations	$ 64,584	$ 21,430	$ -	$ 86,014
Corporate obligations	48,956	-	-	48,956
	$ 113,540	$ 21,430	$ -	$ 134,970
Other	$ 1,628	$ -	$ -	$ 1,628
December 31, 2005				
Available for Sale				
Corporate obligations	$ 7,675	$ -	$ -	$ 7,675
Registered investment companies[1]	32,004	-	(532)	31,472
Common stock	37,628	9,996	-	47,624
Short-term investments	60,143	-	-	60,143
	$ 137,450	$ 9,996	$ (532)	$ 146,914
Held to Maturity				
U.S. Government obligations	$ 60,447	$ 24,957	$ -	$ 85,404
Corporate obligations	45,728	-	-	45,728
	$ 106,175	$ 24,957	$ -	$ 131,132
Other	$ 1,724	$ -	$ -	$ 1,724

(1) Investments included herein are primarily invested in corporate obligations.

Contractual maturities of debt securities at December 31, 2006, were as follows:

Description	Less Than One Year	One Through Five Years	More Than Five Years	Total
		(in thousands)		
Available for Sale	$ 20,000	$ -	$ -	$ 20,000
Held to Maturity	279	1,412	111,849	113,540
	$ 20,279	$ 1,412	$ 111,849	$ 133,540

As discussed in Note 3, realized and unrealized gains and losses related to assets held in the decommissioning trust are deferred as a regulatory liability. Realized and unrealized gains and losses for all other available-for-sale securities were not significant for any period presented.

NOTE 8 – Regulatory Assets and Liabilities

In accordance with SFAS No. 71, we record regulatory assets and liabilities that result from our ratemaking. Our regulatory assets and liabilities at December 31, 2006 and 2005, were as follows:

	2006	2005
	(in thousands)	
Regulatory Assets:		
Unamortized losses on reacquired debt	$ 34,289	$ 36,887
Deferred transportation costs	-	5,919
Deferred asset retirement costs	480	496
DOE decontamination and decommissioning	-	451
Deferred net unrealized losses on derivative instruments	14,969	-
Total Regulatory Assets	$ 49,738	$ 43,753
Regulatory Liabilities:		
Deferred net unrealized gains on derivative instruments	$ -	$ 52,466
North Anna SFAS No. 143 deferral	34,918	32,234
North Anna decommissioning fund market value adjustment	15,537	9,464
Unamortized gains on reacquired debt	1,042	1,107
Total Regulatory Liabilities	$ 51,497	$ 95,271
Regulatory Assets included in Current Assets:		
Deferred energy	$ 14,914	$ 21,328

The regulatory assets will be recognized as expenses concurrent with their recovery through rates and the regulatory liabilities will be recognized as a reduction to expenses concurrent with their refund through rates.

Regulatory assets included in deferred charges are detailed as follows:

- Unamortized losses on reacquired debt are the costs we incurred to purchase our outstanding indebtedness prior to its scheduled retirement. These losses are amortized over the life of the original indebtedness and will be fully amortized in 2023.

- Deferred transportation costs. We began amortizing these costs April 1, 2005, and they were recovered through rates over 21 months and were fully amortized as of December 31, 2006.

- Deferred asset retirement costs for the cumulative effect of change in accounting principle for the Clover and distributed generation facilities as a result of the adoption of SFAS No. 143.

- DOE decontamination and decommissioning represents our share of the costs for decontamination and decommissioning levied under the Atomic Energy Act of 1954, as amended by Title XI of the Energy Policy Act of 1992. These costs were fully amortized as of December 31, 2006.

- Deferred net unrealized losses on derivative instruments. These losses will be matched and recognized in the same period the expense is incurred for the hedged item.

Regulatory liabilities included in deferred credits and other liabilities are detailed as follows:

- Deferred net unrealized gains on derivative instruments. These gains will be matched and recognized in the same period the expense is incurred for the hedged item.

- North Anna SFAS No. 143 deferral is the cumulative effect of change in accounting principle as a result of the adoption of SFAS No. 143.

- North Anna decommissioning fund market value adjustment is the market value adjustment on the decommissioning trust fund.

- Unamortized gains on reacquired debt are the gains we recognized when we purchased our outstanding indebtedness prior to its scheduled retirement. These gains are amortized over the life of the original indebtedness and will be fully amortized in 2023.

Regulatory assets included in current assets are detailed as follows:

- Deferred energy—see Note 1—Deferred Energy—to the Consolidated Financial Statements for our method of accounting for deferred energy.

NOTE 9—Long-term Debt

Long-term debt consists of the following:

	December 31,	
	2006	2005
	(in thousands)	
$250,000,000 principal amount of 2003 Series A Bonds due 2028 at an interest rate of 5.676%	$ 229,167	$ 239,583
$27,755,000 principal amount of 2002 Series A Bonds due 2028 at an interest rate of 5.00%	27,755	27,755
$32,455,000 principal amount of 2002 Series A Bonds due 2028 at an interest rate of 5.625%	32,455	32,455
$300,000,000 principal amount of 2002 Series B Bonds due 2028 at an interest rate of 6.21%	275,000	287,500
$215,000,000 principal amount of 2001 Series A Bonds due 2011 at an interest rate of 6.25%	215,000	215,000
$109,182,937 principal amount of First Mortgage Bonds, 1996 Series B, due 2018 at an effective interest rate of 7.06%	108,601	108,601
$120,000,000 principal amount of First Mortgage Bonds, 1993 Series A, due 2023 at an interest rate of 7.78%	1,000	1,000
Virginia Electric and Power Company Promissory Note (North Anna), due 2008 with variable interest rates (averaging 6.35% in 2006, and 4.18% in 2005)	6,750	6,750
	895,728	918,644
Less unamortized discounts and premiums	(59,547)	(62,747)
Less current maturities	(22,917)	(22,917)
Total Long-term Debt	$ 813,264	$ 832,980

At December 31, 2006, and December 31, 2005, deferred gains and losses on reacquired debt totaled a net loss of approximately $33.2 million and $35.8 million, respectively. Deferred gains and losses on reacquired debt are deferred under regulatory accounting – see Note 8 – Regulatory Assets and Liabilities in Notes to the Consolidated Financial Statements.

Estimated maturities of long-term debt for the next five years and thereafter are as follows:

Year Ending December 31,	(in thousands)
2007	$ 22,917
2008	29,667
2009	22,917
2010	22,917
2011	237,917
2012 and thereafter	559,393
	$ 895,728

The aggregate fair value of long-term debt was $862.9 million and $894.3 million at December 31, 2006 and 2005, respectively, based on current market prices. For debt issues that are not quoted on an exchange, interest rates currently available to us for issuance of debt with similar terms and remaining maturities are used to estimate fair value. We believe that the carrying amount of debt issues with variable rates is a reasonable estimate of fair value.

Substantially all of our assets are pledged as collateral under the Indenture. Under the Indenture, we may not make any distribution, including a dividend or payment or retirement of patronage capital, to our members if an event of default exists under the Indenture. Otherwise, we may make a distribution to our members if (1) after the distribution, our patronage capital as of the end of the most recent fiscal quarter would be equal to or greater than 20% of our total long-term debt and patronage capital, or (2) all of our distributions for the year in which the distribution is to be made do not exceed 5% of the patronage capital as of the end of the most recent fiscal year. For this purpose, patronage capital and total long-term debt and patronage capital do not include any earnings retained in any of our subsidiaries or affiliates or the debt of any of our subsidiaries or affiliates.

NOTE 10—Short-term Borrowing Arrangements

We maintain committed lines of credit and revolving credit facilities to cover short- and intermediate- term funding needs. Currently, we have short-term committed variable rate lines of credit in the aggregate amount of $180.0 million, all of which are available for general working capital purposes. Additionally, we have two committed three-year revolving credit facilities, $50.0 million each, that are available for capital expenditures and general corporate purposes. These facilities expire on June 18, 2007, and January 30, 2009. At December 31, 2006 and 2005, we had no borrowings or letters of credit outstanding under any of these arrangements. We expect the working capital lines of credit and revolving credit facilities to be renewed as they expire.

We maintain a policy which allows our member distribution cooperatives to pre-pay or extend payment on their monthly power bills. Under this policy, we pay interest on early payment balances at a blended investment and outside short-term borrowing rate, and we charge interest on extended payment balances at a blended prepayment and outside short-term borrowing rate. Amounts advanced by our member distribution cooperatives are included in accounts payable—members and totaled $44.2 million and $49.8 million at December 31, 2006 and 2005, respectively. Amounts extended by our member distribution cooperatives are included in accounts receivable—members and totaled $23.5 million and $12.0 million at December 31, 2006 and 2005, respectively.

NOTE 11—Employee Benefits

Substantially all of our employees participate in the National Rural Electric Cooperative Association ("NRECA") Retirement and Security Program, a noncontributory, defined benefit multiple employer master pension plan. We participate in a pension restoration plan, which is intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit from the Retirement and Security Program because of the Internal Revenue Code limitations. The cost of these plans is funded annually by payments to NRECA to ensure that annuities in amounts established by the plan will be available to individual participants upon their retirement. Pension expense was $1.0 million for 2006 and 2005, and was $0.8 million for 2004.

We have also elected to participate in a defined contribution 401(k) retirement plan administered by Diversified Investment Advisors. Under the plan, employees may elect to have up to 100% or $15,000, whichever is less, of their salary withheld on a pretax basis, subject to Internal Revenue Service limitations, and invested on their behalf. We match up to the first 2% of each participant's base salary. Our matching contributions were $126,000, $118,000, and $110,000, in 2006, 2005, and 2004, respectively.

NOTE 12—Insurance

As a joint owner of North Anna, we are a party to the insurance policies that Virginia Power procures to limit the risk of loss associated with a possible nuclear incident at the station, as well as policies regarding general liability and property coverage. All policies are administered by Virginia Power, which charges us for our proportionate share of the costs.

The Price-Anderson Act provides the public up to $10.8 billion of 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 adjustment every five years. Virginia Power has 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 United States, we, jointly with Virginia Power, could be assessed up to $100.6 million for each licensed reactor not to exceed $15.0 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.

Virginia Power's current level of property insurance coverage, $2.55 billion for North Anna, exceeds the Nuclear Regulatory Commission ("NRC") minimum requirement for nuclear power plant licensees of $1.06 billion for each reactor site and includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first to return the reactor to and maintain it in a safe and stable condition and second to decontaminate the reactor and station site in accordance with a plan approved by the NRC. The nuclear property insurance is provided to Virginia Power and us, jointly, by 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 $50.0 million. Based on the severity of the incident, the board of directors of the nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. We, jointly with Virginia Power, 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.

Virginia Power purchases insurance from NEIL to cover the cost of replacement power during the prolonged outage of a nuclear unit due to direct physical damage of the unit. Under this program, we, jointly with Virginia Power, 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 $19.0 million.

Our share of the contingent liability for the coverage assessments described above is a maximum of $31.3 million at December 31, 2006.

NOTE 13—Regional Headquarters, Inc.

We own 50% of Regional Headquarters, Inc. ("RHI"), which holds title to the office building that is being partially leased to us, which we account for under the equity method. We are obligated to make lease payments equal to one half of RHI's annual operating expenses, net of rental income from third party lessees, through the year 2016. During 2006 and 2005, our rent expense was $0.4 million and during 2004 our rent expense was $0.3 million.

Estimated future lease payments, without regard to changes in square footage, third party occupancy rates, operating costs, and inflation are as follows:

Year Ending December 31,	(in thousands)
2007	$ 448
2008	448
2009	448
2010	448
2011	448
2012 and thereafter	2,240
	$ 4,480

NOTE 14—Supplemental Cash Flows Information

Cash paid for interest in 2006, 2005, and 2004, was $54.3 million, $53.8 million, and $54.0 million, respectively.

NOTE 15—Commitments and Contingencies

Legal

Northern Virginia Electric Cooperative ("NOVEC")

Over the past several years, we have had discussions and negotiations with NOVEC about changing the nature of its wholesale power contract from an all-requirements contract to a partial-requirements contract. Our board of directors is composed of representatives of our member distribution cooperatives and we must reach consensus among our member distribution cooperatives before any change to any of our wholesale power contracts can be made. Building a consensus for any change is difficult because any change in our rate setting methodology or provisions of service affects our various member distribution cooperatives differently.

On January 5, 2006, NOVEC filed a complaint with FERC pursuant to Section 206 of the Federal Power Act seeking reformation of its wholesale power contract. Specifically, NOVEC sought "to modify its wholesale power contract to allow NOVEC the flexibility to acquire power and energy over and above that available from NOVEC's share of Old Dominion's existing resources." NOVEC claimed that the wholesale power contract's terms were no longer just and reasonable or in the public interest because the contract was entered into in 1983, and amended and restated in 1992, prior to an allegedly different era of open transmission access and wholesale power markets. NOVEC stated in the complaint that it would not seek to be relieved of its obligations pertaining to its share of our existing power supply resources. Obligations pertaining to our existing resources include debt service, lease rentals, operation and maintenance expenses, interest coverage requirements and other costs and expenses related to our electric generating facilities and existing power purchase arrangements. On March 2, 2006, FERC denied NOVEC's complaint. On April 3, 2006, NOVEC filed a request for rehearing and on May 1, 2006, FERC issued a tolling order to allow additional time to consider the issues. On August 24, 2006, FERC issued it final order denying NOVEC's request for rehearing. On October 20, 2006, NOVEC appealed FERC's denial in the United States Court of Appeals for the District of Columbia. We have intervened in this proceeding. On March 5, 2007, the court issued the procedural schedule and NOVEC's brief is scheduled to be filed on or before May 7, 2007.

We intend to continue to vigorously contest NOVEC's claim and we will not amend or modify the wholesale power contract in any way that could adversely affect our financial condition or that of our other member distribution cooperatives.

Norfolk Southern Railway Company ("Norfolk Southern")

In April 1989, we entered into a coal transportation agreement with Norfolk Southern for delivery of coal to Clover. The agreement, which was later assigned to Virginia Power as operator of Clover, had an initial 20-year term and provides that the amounts payable for coal transportation services are subject to adjustment based on a reference index. In October 2003, Norfolk Southern claimed that it had been using an incorrect reference index to calculate amounts due to it since the inception of the agreement, and that it would begin to escalate prices for these services in the future based on an alternate reference index. On November 26, 2003, together with Virginia Power, we filed suit against Norfolk Southern in the Circuit Court of Halifax County, Virginia, seeking an order to clarify the price escalation provisions in the coal transportation agreement. In its reply to our suit, Norfolk Southern filed a counter-claim and sought (1) recovery from Virginia Power and us for additional amounts resulting from its use of the alternate reference index since December 1, 2003, and (2) an order requiring the parties to calculate the amounts Norfolk Southern claims it was underpaid since the inception of the agreement by using the alternate reference index.

On December 22, 2004, the court found in favor of Norfolk Southern on the issue of ambiguity and held that the price escalation provisions in the agreement were clear and unambiguous. The court later denied Virginia Power's and our motion to file an amended complaint based on additional evidence that was not considered by the court in the original proceedings. The court permitted Virginia Power and us to file an amended answer to Norfolk Southern's counter-claims and our amended answer was filed on March 4, 2005.

On September 1, 2006, the court granted Norfolk Southern's request to substantially dispose of the issues in the case. On September 23, 2006, we, along with Virginia Power, appealed the court's order to the Supreme Court of Virginia. On December 13, 2006, Norfolk Southern filed a motion to dismiss for lack of jurisdiction, contending that we and Virginia Power failed to timely appeal. We intend to vigorously prosecute the appeal, if the Supreme Court of Virginia determines we are able to appeal.

We recorded a liability related to the Norfolk Southern dispute and created the related regulatory asset. The regulatory asset was amortized over 21 months (April 1, 2005 through December 31, 2006) and was fully amortized and collected through rates as of December 31, 2006. The current period charges are being collected through rates. If it is ultimately determined that we owe any such amounts to Norfolk Southern, the amounts are not expected to have a material impact on our financial position or results of operations due to our ability to collect such amounts through rates charged to our member distribution cooperatives.

Ragnar Benson, Inc. ("RBI")

In December 2002, we entered into a contract with RBI for engineering, procurement and construction services relating to the construction of our Marsh Run combustion turbine facility. Construction of the facility began in April 2003 and the facility was required to be substantially complete in the second quarter of 2004. The facility ultimately became available for commercial operation on September 15, 2004, but is still not substantially complete according to the terms of the contract. On December 23, 2004, we terminated the contract with RBI for default and filed suit in the U.S. District Court for the Eastern District of Virginia, Richmond Division, against RBI seeking liquidated damages for delay in completion of the project up to $15.0 million and damages for breach of contract up to $5.0 million. RBI counterclaimed for damages exceeding $15.0 million related to conditions they claim to have encountered during construction. We filed an answer to RBI's counterclaim denying any liability to RBI. During the discovery phase of the legal proceeding, RBI revised its claim from $15.0 million to $33.0 million.

On September 27, 2005, the U.S. District Court for the Eastern District of Virginia, Richmond Division, ruled on motions for partial summary judgment in our claims against RBI. Specifically, the court granted our motion for partial summary judgment pertaining to claims of entitlement to a change order and fraud allegations, it dismissed six of RBI's counterclaims, including all counterclaims pertaining to fraud, and it limited our possible recovery of liquidated damages to the liquidated damages cap of approximately $4.7 million. The trial began

October 11, 2005 and concluded October 26, 2005. During the trial, RBI revised its claim from $33.0 million to $36.0 million.

RBI and its parent companies, The Austin Company and Austin Holdings, Inc., filed for bankruptcy under Chapter 11 of the bankruptcy code on October 14, 2005. The automatic litigation stay was lifted for our litigation with RBI.

On June 13, 2005, we executed an agreement with RBI's surety, Seaboard Surety Company ("Seaboard"), under which it assumed all responsibilities for the final completion of the Marsh Run facility in accordance with the terms of the original agreement with RBI. Because RBI declared bankruptcy during the legal proceeding, we served a lawsuit against Seaboard on February 10, 2006, in order to enforce the eventual outcome of the suit with RBI.

On August 4, 2006, the court ruled in our favor on all remaining issues in the case and awarded us damages of $5.2 million plus expenses. On January 22, 2007, the court entered its final order awarding us an additional $2.5 million for attorneys' fees and certain other costs and expenses. On February 1, 2007, we filed a motion to amend the final order to address our claim for expert witness fees and interest from the date of the trial, totaling approximately $0.8 million. This motion is still pending before the court. After the court rules on this motion, the judgment is final and the appeals process may begin. RBI will have 30 days to appeal any of the court's rulings. We intend to enforce the court's rulings against RBI, to the extent permitted by its bankruptcy proceeding, and against Seaboard.

FERC Proceedings Related to Potential Reorganization

On October 5, 2004, we, together with New Dominion, filed an application at FERC requesting that FERC approve the assignment of our existing wholesale power contracts with our twelve member distribution cooperatives to New Dominion and accept certain changes to our cost-of-service formula to conform it for use by New Dominion for the billing of its sales to the member distribution cooperatives. On December 7, 2004, we filed an application for approval of a new tariff for sales to New Dominion, with charges determined under a cost allocation formula.

On January 14, 2005, NOVEC intervened in the FERC proceedings related to the proposed reorganization. Other interveners in these proceedings included Bear Island Paper Company, LLP and the Virginia State Corporation Commission ("VSCC").

On March 8, 2005, FERC issued an order that set the proposed assignment of the wholesale power contracts for hearing on the limited issue of whether an Old Dominion credit downgrade could raise rates, and, if so, whether the downgrade is due to the proposed transaction. The hearing was conducted on October 18 through 20, 2005, and concluded on November 2, 2005. The initial decision was issued on February 2, 2006, and the judge ruled in our favor on all material issues. On December 21, 2006, FERC issued an order affirming the initial decision indicating that it had not been shown that the credit downgrade experienced by ODEC could raise rates. On January 22, 2007, NOVEC filed a request for rehearing and on February 21, 2007, FERC issued a tolling order to allow for additional time for consideration of the matters.

Also on March 8, 2005, FERC consolidated the October 5, 2004, and December 7, 2004, rate applications and set hearing and settlement procedures. On June 10, 2005, formal settlement procedures were terminated and a judge was assigned to hear the case. Informal settlement talks continued, and on October 13, 2005, we joined with New Dominion in filing a proposed settlement agreement that resolved all issues in dispute in these proceedings among us, Bear Island Paper Company, LLP, and the VSCC. On December 23, 2005, the judge certified the partial settlement to FERC with a recommendation that it be approved. FERC issued an order approving the partial settlement on April 7, 2006, leaving NOVEC, FERC staff and us as participants in the proceeding. The hearing was conducted on October 17 through 19, 2006, and the initial decision was issued on February 5, 2007, when the judge ruled in our favor on all material matters. NOVEC and FERC staff filed exceptions to the ruling on March 7, 2007 and we have 20 days to respond.

Environmental

We are subject to federal, state, and local laws and regulations and permits designed to protect human health and the environment and regulate the emission, discharge, or release of pollutants into the environment. We believe we are in material compliance with all current requirements of such environmental laws and regulations and permits. As with all electric utilities, the operation of our generating units could, however, be affected by future environmental regulations. Capital expenditures and increased operating costs required to comply with any future regulations could be significant.

Our direct capital expenditures for environmental control facilities at Clover and North Anna, excluding capitalized interest, were immaterial in 2006. Based upon information provided by Virginia Power, we anticipate that beginning in 2011, we will have an increase in our direct capital expenditures for environmental control facilities at Clover. In 2006, we did not have any direct capital expenditures for environmental control facilities at our Louisa, Marsh Run or Rock Springs combustion turbine facilities and there are currently no projected capital expenditures for environmental control facilities in 2007, 2008, or 2009.

The most important environmental law affecting our operations is the Clean Air Act. The Clean Air Act requires, among other things, that owners and operators of fossil fuel-fired power stations limit emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x"). In addition, regulations have been issued to limit emissions of mercury, and programs are being proposed to limit emissions of carbon dioxide ("CO_2") and other greenhouse gases.

With respect to SO_2, under the Clean Air Act's Acid Rain Program, each of our fossil fuel-fired plants must obtain SO_2 allowances equal to the number of tons of SO_2 they emit into the atmosphere annually. The total number of allowances is capped, and allowances can be traded. As a facility that was built before the Acid Rain Program, Clover receives an annual allocation of SO_2 allowances at no cost based upon its baseline operations. Newer facilities, including Louisa, Marsh Run and Rock Springs, need to obtain allowances, but because they are primarily gas-fired, the number of SO_2 allowances they must obtain are expected to be minimal and will be supplied from excess SO_2 allowances allocated to Clover. On March 10, 2005, the EPA issued the Clean Air Interstate Rule ("CAIR"), requiring significant reductions of SO_2 and NO_x in the eastern United States, including Virginia and Maryland. During its 2006 session, the Virginia General Assembly adopted legislation setting the framework for the implementation of CAIR in Virginia. The Virginia Department of Environmental Quality ("DEQ") adopted the final CAIR regulation and it is expected to be published in the Virginia Register in the spring. With respect to SO_2, emissions it is expected that Virginia will participate in the federal SO_2 cap and trade program established by CAIR. That program is similar, but is in addition to the Acid Rain Program and would require all of our facilities in Virginia (including Clover) to acquire additional allowances for each ton of SO_2 they emit beginning in 2009, and additional allowances per ton starting in 2015. We are entitled to sufficient SO_2 allowances because of our interest in Clover so that we do not anticipate needing to purchase additional SO_2 allowances for the Louisa, Marsh Run and Rock Springs generating facilities through both phases of CAIR.

Pursuant to the Clean Air Act, both Virginia and Maryland have enacted regulations to reduce the emissions of NO_x by establishing NO_x cap and trade programs similar to the federal SO_2 allowance programs. Both of these programs are being revised to meet the more stringent NO_x emission caps established under CAIR and with respect to the facilities in Virginia, additional NO_x emission reductions mandated by the Virginia General Assembly. Under the current system, Clover is allocated a certain number of NO_x allowances. If Clover, even with use of conventional and advanced pollution control equipment emits more, then additional NO_x emissions allowances will have to be purchased. We have an agreement with Virginia Power to provide us with the option each year to purchase from it the NO_x emissions allowances necessary to compensate for any shortfall between our NO_x emissions allowance requirement for Clover and our portion of the regulatory NO_x emissions allocation for Clover.

Louisa, Marsh Run and Rock Springs will each emit significant amounts of NO_x. In 2006, NO_x allowances were allocated and we anticipate receiving NO_x allowances through 2008. All three sites will be allocated NO_x emission allowances under CAIR. NO_x emission allowances that are not received from the new source set aside pools will be purchased in the market for the operation of all three combustion turbine facilities. We project that we will be able to obtain sufficient quantities of NO_x allowances in the future at commercially reasonable prices, but increased NO_x emissions or increased restrictions could cause the price of allowances to be higher than we expect.

In December 2000, the EPA determined that it was appropriate and necessary to regulate mercury emissions from oil and coal-fired power plants as a hazardous air pollutant under the Clean Air Act. In March 2005, the EPA reversed that earlier decision and instead issued the Clean Air Mercury Rule ("CAMR") which establishes caps for overall mercury emissions that would be implemented in two phases, with the first phase becoming effective in 2010 and the second phase in 2018, and allows the individual states to regulate mercury emissions through a market-based cap and trade program. In response to a request for reconsideration, the EPA confirmed its approach in May 2006. In June 2006, 16 states and several environmental groups filed law suits challenging CAMR and the law suits are currently pending. We cannot predict the outcome of the ongoing challenges of CAMR or what effects any decision may have that would require the EPA to regulate mercury as a hazardous air pollutant. In 2006, the Virginia General Assembly decided to adopt the cap and trade program foreseen in CAMR, subject to certain limitations. If the EPA's decisions are upheld and CAMR is implemented we do not anticipate that any additional measures will be required at Clover due to Clover's existing pollution control requirement which already removes greater than 90% of the mercury.

In addition to traditional air pollutants, the question of climate change has been the focus of much public attention. Several bills have been introduced in Congress to limit emissions of CO_2 and other greenhouse gases believed to contribute to climate change. Also, there are numerous actions at the state and regional level, including the Regional Greenhouse Gas Initiative ("RGGI") established in December 2005 by the governors of seven Northeastern and Mid-Atlantic states. The RGGI provides for a cap and trade system for CO_2 among those states, capping emissions at current levels in 2009, and then reducing emissions 10% by 2019. In 2006, Maryland decided to join the RGGI. Climate change issues are also the subject of several lawsuits, although we were not party to any of those lawsuits. In November 2006, the U.S. Supreme Court heard a case concerning the EPA's authority to regulate CO_2 emissions under the Clear Air Act. The case concerns CO_2 emissions from the transportation sector, but the Court's decision will also influence the regulation of other sectors. We cannot exclude the possibility that future CO_2 emission regulations could have a significant effect on our operations, especially at Clover; however, at this stage we are not able to predict the final form of any such regulation.

The Clean Water Act and applicable state laws regulate water intake structures, discharges of cooling water, storm water run-off and other wastewater discharges at our generating facilities. We are in material compliance with these requirements and with permits that must be obtained with respect to such discharges. Our permits are subject to periodic review and renewal proceedings, and can be made more restrictive over time. Limitations on the thermal discharges in cooling water, or withdrawal of cooling water during low flow conditions, can restrict our operations. During 2006, we experienced no such restrictions; however, such restrictions can arise during drought conditions. Clover has two consent orders with the DEQ. One consent order is to study the impact of withdrawing water to support Clover during low river flow conditions and the other is to relocate one of the landfill discharge pipes from Black Walnut Creek to the Roanoke River. The low flow study has been conducted and the results are being finalized. One of the landfill discharge pipes has been relocated to the Roanoke River.

New legislative and regulatory proposals are frequently proposed on both a federal and state level that would modify the environmental regulatory programs applicable to our facilities. An example is the control of carbon dioxide and other "greenhouse" gases that may contribute to global climate change. With respect to proposed legislation and regulatory proposals that have not yet been formally proposed, we cannot provide meaningful predictions regarding their final form, or their possible effects upon our operations.

We incurred approximately \$5.7 million, \$9.4 million, and \$11.0 million, of expenses, including depreciation, during 2006, 2005, and 2004, respectively, in connection with environmental protection and monitoring activities, such as costs related to the disposal of solid waste, operation of landfills, operation of air emissions reduction equipment, and disposal of hazardous waste material. These expenses were included in fuel expense, operations and maintenance expense, and depreciation, amortization and decommissioning expense. We anticipate expenses to be approximately \$5.0 million in 2007 in connection with environmental protection and monitoring activities, including depreciation.

Tax Increase Prevention and Reconciliation Act of 2005

On May 17, 2006, President Bush signed into law an act entitled the "Tax Increase Prevention and Reconciliation Act of 2005" (the "2005 Tax Act"). Among other provisions, the 2005 Tax Act imposes an excise tax on certain types of leasing transactions entered into by tax-exempt entities. At this time, it is not clear whether the excise tax imposed by the 2005 Tax Act is applicable to our lease transactions. We are continuing to evaluate this legislation and the impact on us; however, specific guidance has not yet been made available. We have revised our estimate of the potential impact and have determined that we do not need to record a liability based upon the currently available information. We have determined that our potential liability for 2006 could range from zero to approximately $1.2 million and that zero represents our best estimate at this time. However, once further guidance is issued, our potential liability under the 2005 Tax Act may change.

Insurance

Under several of the nuclear insurance policies procured by Virginia Power to which we are a party, we are subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance companies. See Note 12—Insurance— to the Consolidated Financial Statements.

Projected Capital Expenditures

Our projected capital expenditures for 2007, 2008 and 2009 are $21.0 million, $22.9 million, and $19.0 million, respectively. Our future projected capital expenditures include a portion of the cost of the nuclear fuel purchased for North Anna and other capital expenditures including generating facility improvements.

NOTE 16—Selected Quarterly Financial Data (Unaudited)

A summary of the quarterly results of operations for the years 2006 and 2005 follow. Amounts reflect all adjustments, consisting of only normal recurring accruals, necessary in the opinion of management for a fair statement of the results for the interim periods. Results for the interim periods may fluctuate as a result of weather conditions, changes in rates and other factors.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in thousands except ratios)				
Statement of Operations Data:					
2006:					
Operating Revenue	$ 203,461	$ 185,952	$ 221,231	$ 206,871	$ 817,515
Operating Margin	16,901	16,436	16,624	23,500	73,461
Net Margin	2,990	3,035	3,089	12,130	21,244
2005:					
Operating Revenue	$ 171,591	$ 160,457	$ 207,491	$ 198,140	$ 737,679
Operating Margin	17,238	16,690	17,192	17,076	68,196
Net Margin	2,939	2,946	2,956	3,268	12,109

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, our management, including the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer conducted an evaluation of the effectiveness of our disclosure controls and procedures. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that all material information required to be filed in this report has been made known to them in a timely matter. We have established a Disclosure Assessment Committee comprised of members from senior and middle management to assist in this evaluation. There have been no significant changes in our internal controls over financial reporting or in other factors that could significantly affect such controls during the previous fiscal quarter.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Directors

We are governed by a board of 25 directors, consisting of two representatives from each of our member distribution cooperatives and one representative from TEC. Each of our twelve member distribution cooperatives nominates two directors at least one of whom must be a director of that member in good standing. One director currently serves as a director on behalf of a member distribution cooperative and TEC. The candidates for director are elected to our board of directors by voting delegates from each of our member distribution cooperatives elected by each member distribution cooperatives' board of directors. Each elected candidate is authorized to represent that member for a renewable term of one year at our annual meeting. This election process occurs annually. Our board of directors sets policy and provides direction to our President and Chief Executive Officer. Beginning in 2007, the board of directors generally meets every other month.

Information concerning our directors, including principal occupation and employment during the past five years and directorships in public corporations, if any, is listed below.

John William Andrew, Jr. (53). President and Chief Executive Officer of Delaware Electric Cooperative since January 2005. Mr. Andrew also served as Vice President, Engineering and Operations from 1998 to 2004. Mr. Andrew has been a Director of ODEC since 2005.

M. Johnson Bowman (61). President and Chief Executive Officer of Mecklenburg Electric Cooperative since 2001. Mr. Bowman also served as Executive Vice President and General Manager of Mecklenburg Electric Cooperative from 1981 to 2001. Mr. Bowman has been a Director of ODEC since 1974.

M Dale Bradshaw (53). Chief Executive Officer of Prince George Electric Cooperative since 1995. Mr. Bradshaw has been a Director of ODEC since 1995.

Vernon N. Brinkley (60). President and Chief Executive Officer of A&N Electric Cooperative since 2003. Mr. Brinkley also served as President of A&N Electric Cooperative from 1995 to 2003 and as Executive Vice President and General Manager from 1982 to 1995. Mr. Brinkley has been a Director of ODEC since 1982.

Calvin P. Carter (82). Owner of Carter's Store since 1960 and Carter Stone Co., a stone quarry since 1965. Mr. Carter has served as a member of the Campbell County Board of Supervisors since 1979. Mr. Carter has been a Director of ODEC since 1991 and a Director of Southside Electric Cooperative since 1972.

Glenn F. Chappell (63). Self-employed farmer since 1961. Mr. Chappell has been a Director of ODEC since 1995 and a Director of Prince George Electric Cooperative since 1985.

Kent D. Farmer (49). President and Chief Executive Officer of Rappahannock Electric Cooperative since 2004. Mr. Farmer also served as Chief Operating Officer of Rappahannock Electric Cooperative from 1999 to 2004. Mr. Farmer has been a Director of ODEC since 2004.

Stanley C. Feuerberg (55). President and Chief Executive Officer of Northern Virginia Electric Cooperative since 1992. Mr. Feuerberg has been a Director of ODEC since 1992.

William C. Frazier (76). Insurance broker of Associates Insurance Agency, a general insurance company, since 1999. Mr. Frazier has been a Director of ODEC since 2003 and a Director of Rappahannock Electric Cooperative since 1981.

Fred C. Garber (62). Retired, formerly President of Mt. Jackson Farm Service, a retail farm supply company, from 1973 to 2003. Mr. Garber has been a Director of ODEC since 2005 and a Director of Shenandoah Valley Electric Cooperative since 1984.

Hunter R. Greenlaw, Jr. (61). President of Greenlaw, Edwards & Leake, Inc., a real estate development and general contracting company since 1974. Mr. Greenlaw has been a Director of ODEC since 1991 and a Director of Northern Neck Electric Cooperative since 1979.

Bruce A. Henry (61). Owner and Secretary/Treasurer of Delmarva Builders, Inc., a building contracting company since 1981. Mr. Henry has been a Director of ODEC since 1993 and a Director of Delaware Electric Cooperative since 1978.

Wade C. House (60). Vice President/Branch Manager of APAC-Atlantic, Inc., a highway construction company since 1972. Mr. House has been a Director of ODEC since 2004 and a Director of Northern Virginia Electric Cooperative since 1993.

Frederick L. Hubbard (66). President and Chief Executive Officer of Choptank Electric Cooperative since 2001. Mr. Hubbard also served as Senior Vice President and Chief Executive Officer of Choptank Electric Cooperative from 1991 to 2001. Mr. Hubbard has been a Director of ODEC since 1991.

David J. Jones (58). Owner/operator of Big Fork Farms since 1970 and Vice President of Exchange Warehouse, Inc. from 1996 to 2006. Mr. Jones has been a Director of ODEC since 1986 and a Director of Mecklenburg Electric Cooperative since 1982.

Bruce M. King (60). General Manager of BARC Electric Cooperative since 2003. Prior to that Mr. King was General Manager of Cherryland Electric Cooperative from 1993 to 2002. Mr. King has been a Director of ODEC since 2003.

William M. Leech, Jr. (79). Retired, former self-employed farmer from 1955 to 1988. Mr. Leech has been a Director of ODEC since 1977 and a Director of BARC Electric Cooperative since 1970.

M. Larry Longshore (65). President and Chief Executive Officer of Southside Electric Cooperative since 1998. Prior to that Mr. Longshore was President and Chief Executive Officer of Newberry Electric Cooperative from 1973 to 1998. Mr. Longshore has been a Director of ODEC since 1998.

Paul E.Owen (56). Director of Business Management with Smithfield Deli Group since 1974. Mr. Owen has been a Director of ODEC since 2007 and a Director of Community Electric Cooperative since 2000.

James M. Reynolds (59). President of Community Electric Cooperative since 2001. Mr. Reynolds also served as General Manager of Community Electric Cooperative from 1977 to 2001. Mr. Reynolds has been a Director of ODEC since 1977.

Myron D. Rummel (54). President and Chief Executive Officer of Shenandoah Valley Electric Cooperative since 2005. Mr. Rummel also served as Vice President, Engineering and Operations of Shenandoah Valley Electric Cooperative from 1993 to 2005. Mr. Rummel has been a Director of ODEC since 2005.

Philip B. Tankard (78). Office manager for Tankard Nurseries since 1985. Mr. Tankard has been a Director of ODEC since 2002 and a Director of A&N Electric Cooperative since 1960.

Gregory W. White (54). President and Chief Executive Officer of Northern Neck Electric Cooperative since 2005. Mr. White served as Senior Vice President of Power Supply of ODEC from 2004 to 2005, Senior Vice President Engineering and Operations of ODEC from 2002 to 2004 and Senior Vice President Retail and Alliance Management of ODEC from 2000 to 2002. Mr. White has been a Director of ODEC since 2005.

Carl R. Widdowson (68). Self-employed farmer since 1956. Mr. Widdowson has been a Director of ODEC since 1987 and a Director of Choptank Electric Cooperative since 1980.

Audit Committee Financial Expert

We presently do not have an audit committee financial expert because of our cooperative governance structure and the resulting experience all of our directors have with matters affecting electric cooperatives in their roles as a chief executive officer or director of one of our member distribution cooperatives. In addition, the audit committee employs the services of accounting and financial consultants as it deems necessary.

Executive Officers

Our President and Chief Executive Officer administers our day-to-day business and affairs. Our executive officers, their respective ages, positions and recent business experience are listed below.

Jackson E. Reasor (54). President and Chief Executive Officer of ODEC and the Virginia, Maryland and Delaware Association of Electric Cooperatives (the "VMDA"), an electric cooperative association which provides services to its members and certain other electric cooperatives, since 1998. Mr. Reasor served as Vice President of First Virginia Bank from 1997 until 1998; President and Chief Executive Officer of Premier Trust Company from 1995 until 1997; a Virginia State Senator from 1992 until 1998; and an attorney with Galumbeck, Simmons & Reasor from 1992 until 1995.

Robert L. Kees (54). Senior Vice President and Chief Financial Officer since January 1, 2006. Mr. Kees also served as our Vice President and Controller from March 2004 to December 2005, as Assistant Vice President and Controller from March 2000 to February 2004 and as Controller from January 1994 to February 2000.

Lisa M. Johnson (41). Senior Vice President of Power Supply since May 2006. Prior to joining ODEC, Ms. Johnson served as Vice President at Mirant Corporation from 2001 to 2006.

John C. Lee, Jr. (46). Vice President of Member and External Relations since April 2004. Mr. Lee served as our Vice President Cooperative Affairs/Assistant to the President from March 2000 to March 2004; and as our Manager of Administration from February 1995 to February 2000.

Elissa M. Ecker (47). Vice President of Human Resources since November 2004. Prior to joining ODEC, Ms. Ecker served as Director of Human Resources of Xperts, Inc. from 2003 to 2004; as Director of Human Resources of Securicor New Century, L.L.C. from 2002 to 2003; and as Director of Human Resources of Manorhouse Retirement Centers, Inc. from 1997 to 2002.

Code of Ethics

We have a Code of Ethics, which applies to our President and Chief Executive Officer, Senior Vice President and Chief Financial Officer, and Vice President and Controller. A copy of this Code of Ethics is available without charge by sending a written request for the Code of Ethics to Old Dominion Electric Cooperative, Attention Mr. Robert L. Kees, Senior Vice President and Chief Financial Officer, 4201 Dominion Boulevard, Glen Allen, VA 23060.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

General Philosophy

Our compensation philosophy has four objectives:

- attract and retain a qualified, diverse workforce through a competitive compensation program;
- provide equitable and fair compensation;
- support our business strategy; and
- ensure compliance with applicable laws and regulations.

Total Compensation Package

We compensate our senior management through the use of a total compensation package to include base salary, competitive benefits, and the potential of a bonus. The compensation of the chief executive officer ("CEO") of ODEC is reviewed by the executive committee of our board of directors and a recommendation is then provided to our entire board of directors. The entire board of directors approves our CEO's compensation. Our board of directors determines an annual salary derived from third party market data from the relevant labor market for positions of similar responsibilities. Our compensation structure is aligned with the external market through the use of a market pricing approach.

Targeted Overall Compensation

We engaged a consulting firm to assist us in establishing a market-based compensation program and to provide an annual review of our market analysis for all of our employees, including senior management. Our compensation program utilizes the creation and maintenance of accurate, detailed job descriptions as an instrument to establish benchmarked positions. The market compensation information includes salary data for positions within the determined competitive labor market. Our job descriptions are reviewed annually and include essential and non-essential responsibilities, required knowledge, skills and abilities, formal education and experience necessary to accomplish the requirements of the position which in turn helps us achieve operational goals. Utilizing this information, our human resources department determines a market-based salary for each position. A third-party consultant, Burton Fuller Management, Inc., reviews the market-based salary data we compiled for reasonableness and fairness annually. Our board of directors has defined market-based salary as approximately 95% to 100% of the 50th percentile of the market, excluding new hires that may be hired at 90% of the 50th percentile of market until a learning period is complete.

Process

We do not have a standing compensation committee because our board of directors has delegated to our President and CEO the authority to establish and adjust compensation for all other employees other than himself. We have a sub-committee of our board of directors, the executive committee, which recommends compensation for our CEO to the entire board of directors and the entire board of directors approves the compensation. The compensation for all other employees, including members of senior management other than the CEO, is determined by our CEO based upon market-based salary data. On an annual basis our board of directors reviews the performance and compensation of our CEO and our CEO reviews the performance and compensation of the remaining senior management.

Our CEO is also the CEO of the Virginia, Maryland and Delaware Association of Electric Cooperatives ("VMDA") and their board of directors also approves the compensation of the CEO. The VMDA contributed $36,000 to our CEO's salary for 2006 and will contribute $40,000 in 2007.

Base Salaries

We are an electric cooperative and do not have any stock and as a result, we do not have equity-based compensation programs. For this reason, substantially all of our compensation to our executive officers is provided in the form of base salary. We want to provide our senior management with a level of assured cash compensation in the form of base salary that is commensurate with the duties and responsibilities of their positions. These salaries were determined based on market data and internal structure for positions with similar responsibilities.

Bonuses

Our practice has been to, on infrequent occasions, award cash bonuses related to a specific event, such as the consummation of a significant transaction. On an annual basis, our board of directors determines the bonus criteria for our CEO and our CEO determines bonus criteria for all other executive officers. At the discretion of our board of directors, our CEO may be awarded an annual bonus; and, at the discretion of our CEO, other senior management may be awarded an annual bonus. We have not had any significant transactions in recent years and accordingly, our CEO and other members of our senior management were not awarded a bonus in any of the last three years. Our chief financial officer was awarded a $2,000 bonus when he was in his position as Vice President and Controller in 2004 under a bonus program generally available to all employees other than the CEO. Typically, senior management does not participate in this program.

Severance Benefits

We believe that companies should provide reasonable severance benefits to the CEO. With respect to our CEO, these severance benefits reflect the fact that it may be difficult to find comparable employment within a short period of time. In addition, while it is possible to provide salary continuation to a CEO during the job search process, which in some cases may be less expensive than a lump-sum severance payment, we prefer to pay a lump-sum severance payment to sever the relationship as soon as practicable if the severance is for cause. Our CEO's contractual rights to amounts following severance are set forth in his employment agreement. None of our other members of senior management have any contractual severance benefits.

Plans

Retirement Plans

ODEC maintains a defined benefit pension plan which is available to all employees, with limited exceptions, who work at least 1,000 hours per year. This plan is a qualified pension plan under Section 401(a) of the Internal Revenue Code. Benefits, which accrue under the plan, are based upon the base annual salary as of November of the previous year.

We also have a 401(k) plan which is available to all employees in regular positions. Under the 401(k) plan for 2006, employees may elect to have up to 100% or $15,000, whichever is less, of their salary withheld on a pre-tax basis, subject to Internal Revenue Service limitations, and invested on their behalf. We match up to the first 2% of each participant's base salary. Also, a catch-up contribution is available for participants in the plan once they attain age 50. The maximum catch-up contribution for 2006 was $5,000.

In addition, in 2006 ODEC entered into a non-qualified executive deferred compensation plan (the "Deferred Compensation Plan"). Our board of directors, at its discretion, determines who may participate in the plan as well as an annual contribution, if any, up to the maximum amount allowed by regulations. Currently, our board of directors has determined that our CEO is the only participant in this plan and in 2006 and we made a $15,000 contribution to the plan for his benefit.

Pension Restoration Plan

We participate in a pension restoration plan, which is intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit from the Retirement and Security Plan because of the Internal Revenue Code limitations. Currently, our CEO is the only participant in this plan. Other executive officers may participate in this plan in the future.

Perquisites and Other Benefits

Our board of directors reviews the perquisites that our CEO receives during contract discussions with our CEO. The perquisite for Mr. Reasor is expenses for personal use of a company automobile amounted to $2,602 in 2006 and $2,406 in 2005.

Senior management also participates in ODEC's other benefit plans on the same terms as other employees. These plans include the defined benefit pension plan, the 401(k) plan, medical and dental insurance, vision insurance, life insurance & accidental death and dismemberment, long-term disability, long-term care insurance, medical reimbursement and dependent care flexible spending accounts, health club membership, vacation and sick leave. Relocation benefits are reimbursed for all employees who transfer to another location at the request or convenience of ODEC in accordance with ODEC's relocation policy. We believe these benefits are customary for similar employers.

Change in Control

There is no provision in our CEO's employment agreement or any other arrangements with any senior management that increases or decreases any amounts payable to him or her as a result of a change in control.

Summary Compensation Table

The following table sets forth information concerning compensation awarded to, earned by or paid to our CEO, our chief financial officer and three other senior executive officers for services rendered to us in all capacities during each of the last three fiscal years. The table also identifies the principal capacity in which each of these executives serves or served.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary	Bonus	Change in Pension Value and Non-Qualified Deferred Compensation	All Other Compensation[1]	Total
Jackson E. Reasor	2006	$ 351,667	$ -	$ 96,656	$ 62,625	$ 510,948
President and Chief	2005	330,833	-	85,571	55,400	471,804
Executive Officer	2004	311,667	-	58,614	51,672	421,953
Robert L. Kees	2006	214,569	-	60,029	28,228	302,826
Senior Vice President	2005	140,535	-	55,429	24,071	220,035
and Chief Financial Officer	2004	133,843	2,000	36,341	21,490	193,674
Lisa M. Johnson	2006	147,384	-	-	1,008	148,392
Senior Vice President	2005	-	-	-	-	-
Power Supply	2004	-	-	-	-	-
John C. Lee, Jr.	2006	157,516	-	41,309	27,424	226,249
Vice President of Member	2005	141,148	-	35,637	23,836	200,621
and External Relations	2004	128,447	-	25,010	19,396	172,853
Elissa M. Ecker	2006	141,765	-	5,483	25,882	173,130
Vice President of	2005	134,750	-	269	3,098	138,117
Human Resources	2004	17,088	-	-	92	17,180

(1) The items included in All Other Compensation are identified in the All Other Compensation table below.

Employment Agreement

On December 18, 2006, ODEC entered into an employment agreement with Jackson E. Reasor, our President and CEO. The agreement is for the term of five years, with an automatic one-year extension unless Mr. Reasor or the Employer gives written notice 30 days prior to the expiration of the agreement. The agreement provides that he will receive an annual salary of $360,000, effective as of June 1, 2006, subject to annual adjustment by the boards of directors of the ODEC and the VMDA (collectively, the "Employer"). The boards of directors of the Employer also may grant Mr. Reasor an annual bonus at their discretion. Mr. Reasor will also be entitled to participate in all benefit plans available to the employees of the Employer. Virginia, Maryland and Delaware Association of Electric Cooperatives is expected to contribute $36,000 of Mr. Reasor's salary in 2006.

Under the agreement, if Mr. Reasor voluntarily terminates his employment following material breach by the Employer or the Employer terminates him without specified cause, the Employer will pay Mr. Reasor a salary at the rate in effect on the date of termination for one year, plus medical insurance benefits, with limited exceptions. If the agreement is not continued at the end of the stated term, the Employer will pay Mr. Reasor a salary at the rate in effect on the date of termination for six months.

Where the termination is without "cause" or the CEO terminates employment for "good reason" the employment agreement provides for benefits equal to one year of base salary and medical insurance. However, the medical insurance will cease if he becomes eligible for medical insurance coverage by virtue of his employment with another company. In addition, a terminated CEO is entitled to receive any benefits that he otherwise would have been entitled to receive under our 401(k) plan, frozen pension plan and supplemental retirement plans, although those benefits are not increased or accelerated. We believe that these levels are consistent with the general practice among generation and transmission cooperatives, although we have not conducted a study to confirm this.

Based upon a hypothetical termination date of December 31, 2007, the severance benefits for our CEO would have been entitled to would be as follows:

Base Salary[1]	$ 360,000
Targeted bonus	-
Healthcare and other insurance benefits	13,619
Total	$ 373,619

[1] This calculation is based upon Mr. Reasor's current salary. Mr. Reasor is scheduled for a salary review in June 2007.

Under our employment contract with our CEO, "cause" is (1) gross incompetence, insubordination, gross negligence, willful misconduct in office or breach of a material fiduciary duty, which includes a breach of confidentiality; (2) conviction of a felony, a crime of moral turpitude or commission of an act of embezzlement or fraud against ODEC or the VMDA (collectively, the "Employer") or any subsidiary or affiliate thereof; (3) the CEO's material failure to perform a substantial portion of his duties and responsibilities hereunder; but only after Employer provides the CEO written notice of such failure and gives him 30 days to remedy the situation; (4) deliberate dishonesty of the CEO with respect to ODEC or any of its subsidiaries or affiliates.

The CEO may terminate his employment with or without good reason by written notice to the board of directors effective 60 days after receipt of such notice by the board of directors. If the CEO terminates his employment for good reason, then the CEO is entitled to the salary specified above in the "without cause" paragraph. The CEO will not be required to render any further services. Upon termination of employment by the CEO without good reason, then the CEO is not entitled to further compensation. "Good reason" is our failure to maintain compensation and benefits or our material breach of any provision of the employment contract, which failure or breach continued for more than 30 days after the date on which our board of directors received such notice.

Defined Benefit Plan

We have elected to participate in the National Rural Electric Cooperatives Association ("NRECA") Retirement and Security Program (the "Plan"), a noncontributory, defined benefit, multiple-employer, master pension plan maintained and administered by the NRECA for the benefit of its member systems and their employees. The Plan is a qualified pension plan under Section 401(a) of the Internal Revenue Code of 1986. The following table lists the estimated current annual pension benefit payable at "normal retirement age," age 62, for participants in the specified final average salary and years of benefit service categories for the given current multiplier of 1.7%. Benefits, which accrue under the Plan, are based upon the base annual salary as of November of the previous year. As a result of changes in Internal Revenue Service regulations, the base annual salary used in determining benefits is limited to $225,000 effective January 1, 2007.

PENSION BENEFITS TABLE

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Year
Jackson E. Reasor	NRECA Retirement and Security Plan	7.08	$ 272,194	-
	Pension Restoration Plan		119,003	
Robert L.Kees	NRECA Retirement and Security Plan	14.00	320,200	-
Lisa M. Johnson	NRECA Retirement and Security Plan	-	-	-
John C. Lee, Jr.	NRECA Retirement and Security Plan	13.58	204,822	-
Elissa M. Ecker	NRECA Retirement and Security Plan	1.83	5,752	-

The pension benefits indicated above are the estimated amounts payable by the Plan, and they are not subject to any deduction for Social Security or other offset amounts. The participant's annual pension at his or her normal retirement date is equal to the product of his or her years of benefit service times final average salary times the multiplier in effect during years of benefit service. The multiplier was 1.7% commencing January 1, 1992. The number of years of credited service is as of the "normal retirement age" for each of the named executives. The present value of accumulated benefit is calculated assuming that the executive retires at the normal retirement age per the plan and that they receive lump sums. The lump sum amounts are calculated using the 30-year Treasury rate (4.73% for 2006 and 4.89% for 2005) and the required Internal Revenue Service mortality table for lump sum payments (1994 GAS, projected to 2002, blended 50%/50% for unisex mortality.)

We participate in a pension restoration plan, which is intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit from the Retirement and Security Plan because of the Internal Revenue Code limitations.

Deferred Compensation Plan

On December 18, 2006, in connection with the execution of the employment agreement with our CEO, ODEC adopted the Deferred Compensation Plan for the purpose of providing supplemental deferred compensation to Mr. Reasor in an amount within the statutory maximums permitted under Section 457 of the Internal Revenue Code. The Deferred Compensation Plan is restricted to those executive employees designated by the board of directors of ODEC who are generally responsible for ongoing operations, responsible for and have general supervision over the overall financial condition, setting and executing overall corporate policies and practices, and supervising large numbers of employees and who elect to participate in the Deferred Compensation Plan by agreeing to a deferral of a portion of their current compensation. Currently, Mr. Reasor is the only participant in the Deferred Compensation Plan. Under the Deferred Compensation Plan, annual deferrals cannot exceed 100% of Mr. Reasor's annual compensation or $15,000 (for 2006), adjusted by and subject to specified tax laws (the "deferral limit"), during any year in which ODEC is exempt from federal income taxation. During the last three years before Mr. Reasor attains the normal retirement age under ODEC's primary pension plan, currently age 62, the deferral limit is increased to the lesser of two times the deferral limit or the deferral limit plus the amount Mr. Reasor was eligible to but did not defer under the Deferred Compensation Plan. Amounts credited to him under the Plan will be credited with earnings or losses equal to those made by an investment in one or more funds of a specified regulated investment company designated by him. Distributions under the Deferred Compensation Plan generally commence upon severance of employment, whether upon termination, retirement or death.

The following table sets forth the non-qualified deferred compensation paid to our executive officers in 2006:

NON-QUALIFIED DEFERRED COMPENSATION BENEFITS TABLE

Name	Executive Contributions in Last Fiscal Year[1]	Registrant Contributions in Last Fiscal year[1]	Aggregate Earnings in Last Fiscal Year[1]	Aggregate Withdrawals/ Distributions	Aggregate Balance at Last Fiscal Year End
Jackson E. Reasor	-	$ 15,000	$ 74	-	$ 15,074
Robert L.Kees	n/a	n/a	n/a	n/a	n/a
Lisa M. Johnson	n/a	n/a	n/a	n/a	n/a
John C. Lee, Jr.	n/a	n/a	n/a	n/a	n/a
Elissa M. Ecker	n/a	n/a	n/a	n/a	n/a

(1) These amounts are not included in summary compensation table.

The following table sets forth information concerning all other compensation awarded to, earned by or paid to these executives during the last completed fiscal year.

ALL OTHER COMPENSATION

Name	Perquisites and Other Personal Benefits[1]	Company Contributions to Defined Benefit Plans	Company-paid Insurance Premiums	All Other Compensation
Jackson E. Reasor[2]	$ 7,002	$ 53,823	$ 1,800	$ 62,625
Robert L.Kees	4,292	22,921	1,015	28,228
Lisa M. Johnson	-	-	1,008	1,008
John C. Lee, Jr.	3,150	23,244	1,030	27,424
Elissa M. Ecker	2,835	22,068	979	25,882

(1) Perquisites and other personal benefits is composed of contributions made by ODEC to the 401(K) plan.

(2) Perquisites and other personal benefits includes $2,602 for personal use of a company automobile.

Board of Directors Compensation

It is our policy to compensate the members of our board of directors who are not employed by one of our member distribution cooperatives ("outside directors"). Our outside directors were compensated by a monthly retainer of $1,700 in 2006. Beginning in 2007, the monthly retainer is $2,000. They are also paid for meetings at a rate of $400 per in person meeting and $200 per teleconference, if the meeting date falls outside the normal board of directors meeting dates. All directors are reimbursed for out-of-pocket expenses incurred in attending meetings. Our directors receive no other compensation. Our directors do not have pension benefits, non-equity incentive plan compensation, or other perquisites and because we are a cooperative, we do not have stock or other equity options. The following table sets forth the compensation we paid to our directors in 2006:

DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash[1]
Calvin P. Carter	$ 28,000
Glenn F. Chappell	24,200
Carl R. Eason	23,000
William C. Frazier	23,400
Fred C. Garber	25,600
Hunter R. Greenlaw, Jr.	27,600
Bruce A. Henry	26,600
Wade C. House	21,400
David J. Jones	26,200
William M. Leech, Jr.	22,400
Philip B. Tankard	24,200
Carl R. Widdowson	32,200

[1] Our directors received no compensation other than as set forth in this column.

Compensation Committee Interlocks and Insider Participation

As described above, we do not have a compensation committee but the executive committee of our board of directors establishes and the full board of directors approves all compensation and awards to the CEO. Our board of directors has delegated to our CEO the authority to establish and adjust compensation for all other employees other than himself. No member of our board of directors is or previously was an officer or employee of ODEC or is or has engaged in transactions with ODEC, with one exception. Gregory W. White was an employee of ODEC from 1995 to 2005 when he left his position as Senior Vice President of Power Supply to be the President and Chief Executive Officer of Northern Neck Electric Cooperative, one of our twelve member distribution cooperatives. As the President and Chief Executive Officer of one of our member distribution cooperatives, he serves on our board of directors. Our directors are, however, members or directors of our member distribution cooperatives. See "Cooperative Status" in Item 1 and "Directors and Officers of the Registrant" in Item 10.

Compensation Committee Report

The board of directors, including the Executive Committee of the board of directors, has reviewed and discussed with the management of ODEC the contents of the section entitled "Compensation Discussion and Analysis" and based on such review and discussion has recommended and approved to the board of directors its inclusion in this annual report.

John William Andrew, Jr.
M. Johnson Bowman*
M Dale Bradshaw
Vernon N. Brinkley
Calvin P. Carter
Glenn F. Chappell
Kent D. Farmer

Stanley C. Feuerberg
William C. Frazier
Fred C. Garber
Hunter R. Greenlaw, Jr.*
Bruce A. Henry*
Wade C. House*
Frederick L. Hubbard*
David J. Jones
Bruce M. King
William M. Leech, Jr.
M. Larry Longshore
Paul E. Owen
James M. Reynolds*
Myron D. Rummel
Philip B. Tankard
Gregory W. White
Carl R. Widdowson

*Denotes member of the Executive Committee of the board of directors

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Not Applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Because we are a cooperative, all of our directors are representatives of our member distribution cooperatives, which are our principal customers. Due to the extent of the payments by each member distribution cooperative to us, our directors are not independent based on the definition of "independence" of the New York Stock Exchange.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table presents fees for services provided by Ernst & Young LLP for fiscal 2006 and 2005. All Audit, Audit-Related, and Tax Fees shown below were pre-approved by the Audit Committee in accordance with its established procedures.

	2006	2005
Audit Fees (a)	$ 267,831	$ 285,850
Audit-Related Fees (b)	45,725	151,480
Tax Fees (c)	60,180	3,960
Total	$ 373,736	$ 441,290

a) Fees for professional services provided for the audit of the Company's annual financial statements as well as reviews of the Company's quarterly reports on Form 10-Q, accounting consultations on matters addressed during the audit or interim reviews, and SEC filings and offering memorandums including comfort letters, consents, and comment letters.
b) Fees for professional services which principally include accounting consultations and services in connection with internal control matters.
c) Fees for professional services for tax-related advice and compliance

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

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

1. Financial Statements

See Index on page 50

2. Financial Statement Schedules

Not applicable.

3. Exhibits

Exhibits

*3.1 Amended and Restated Articles of Incorporation of Old Dominion Electric Cooperative (filed as exhibit 3.1 to the Registrant's Form 10-Q, File No. 33-46795, filed on August 11, 2000).

*3.2 Bylaws of Old Dominion Electric Cooperative, Amended and Restated as of September 10, 2002, as amended on September 14, 2004 (filed as exhibit 3.1 to the Registrant's Form 10-Q, File No. 000-50039, filed on November 15, 2004).

*4.1 Indenture of Mortgage and Deed of Trust, dated as of May 1, 1992, between Old Dominion Electric Cooperative and Crestar Bank, as Trustee (filed as exhibit 4.1 to the Registrant's Form 10-K for the year ended December 31, 1992, File No. 33-46795, filed on March 30, 1993).

*4.2 Third Supplemental Indenture, dated as of May 1, 1993, to the Indenture of Mortgage and Deed of Trust, dated as of May 1, 1992, between Old Dominion Electric Cooperative and Crestar Bank, as Trustee, including the form of the First Mortgage Bonds, 1993 Series A (filed as exhibit 4.1 to the Registrant's Form 10-Q for the quarter ended June 30, 1993, File No. 33-46795, filed on August 10, 1993).

*4.3 Fourth Supplemental Indenture, dated as of December 15, 1994, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and Crestar Bank, as Trustee (filed as exhibit 4.5 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*4.4 Fifth Supplemental Indenture, dated as of February 29, 1996, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and Crestar Bank, as Trustee including the form of the First Mortgage Bonds, 1996 Series A and 1996 Series B (filed as exhibit 4.6 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*4.5 Eleventh Supplemental Indenture, dated as of September 1, 2001, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (formerly Crestar Bank), as Trustee, including the form of the 2001 Series A Bond (filed as exhibit 4.1 to the Registrant's Form 10-Q/A for the quarter ended September 30, 2001, File No. 33-46795, filed on November 20, 2001).

*4.6 Thirteenth Supplemental Indenture, dated as of November 1, 2002, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank

(Formerly Crestar Bank), as Trustee, including the form of the 2002 Series A Bond (filed as exhibit 4.14 to Amendment No. 1 to the Registrant's Form S 3, File No. 333-100577, on November 25, 2002).

*4.7 Fourteenth Supplemental Indenture, dated as of December 1, 2002, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (Formerly Crestar Bank), as Trustee, including the form of the 2002 Series B Bond (filed as exhibit 4.1 to the Registrant's Form 8-K, File No. 000-50039, on December 27, 2002).

*4.8 Fifteenth Supplemental Indenture, dated as of May 1, 2003, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (Formerly Crestar Bank), as Trustee (filed as Exhibit 4.A to the Registrant's Form 10-K for the year ended December 31, 2003, File No. 000-50039, on March 22, 2004).

*4.9 Sixteenth Supplemental Indenture, dated as of July 1, 2003, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (Formerly Crestar Bank), as Trustee, including the form of the 2003 Series A Bond (filed as Exhibit 4.1 to the Registrant's Form 8-K, File No. 000-50039, on July 25, 2003).

*4.10 Seventeenth Supplemental Indenture, dated as of January 1, 2004, to the Indenture of Mortgage and Deed of Trust dated as of May 1, 1992, between Old Dominion Electric Cooperative and SunTrust Bank (formerly Crestar Bank), as Trustee (filed as Exhibit 4.B to the Registrant's Form 10-K for the year ended December 31, 2003, File No 000-50039, on March 22, 2004).

*4.11 Amended and Restated Indenture, dated as of September 1, 2001, between Old Dominion Electric Cooperative and SunTrust Bank, as Trustee (filed as exhibit 4.2 to Registrant's Form 10-Q/A for the quarter ended September 30, 2001, File No. 33-46795, filed on November 20, 2001).

*4.12 First Supplemental Indenture, dated as of December 1, 2002, to the Amended and Restated Indenture, dated as of September 1, 2001, between Old Dominion Electric Cooperative and SunTrust Bank, as Trustee (filed as Exhibit 4.2 to the Registrant's Form 8-K, File No. 000-50039, on December 27, 2002).

*10.1 Nuclear Fuel Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of December 28, 1982, amended and restated October 17, 1983 (filed as exhibit 10.1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.2 Purchase, Construction and Ownership Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of December 28, 1982, amended and restated October 17, 1983 (filed as exhibit 10.2 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.3 Operating and Power Sales Agreement, dated as of October 12, 2004, among Virginia Electric and Power Company, Old Dominion Electric Cooperative, and New Dominion Energy Cooperative (filed as exhibit 10.1 to the Registrant's Form 10-Q, File No. 000-50039, on November 15, 2004). Amended and Restated Interconnection and Operating Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of July 29, 1997 (filed as exhibit 10.5 to the Registrant's Form 10-K for the year ended December 31, 1998, File No. 33-46795, on March 25, 1999).

*10.4 Clover Purchase, Construction and Ownership Agreement between Old Dominion Electric Cooperative and Virginia Electric and Power Company, dated as of May 31, 1990 (filed as exhibit 10.4 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.5 Amendment No. 1 to the Clover Purchase, Construction and Ownership Agreement between Old Dominion Electric Cooperative and Virginia Electric and Power Company, effective March 12, 1993 (filed as exhibit 10.34 to the Registrant's Form S-1 Registration Statement, File No. 33-61326, filed on April 19, 1993).

*10.6 Clover Operating Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of May 31, 1990 (filed as exhibit 10.6 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.7 Amendment to the Clover Operating Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, effective January 17, 1995 (filed as exhibit 10.8 to the Registrant's Form 10-K for the year ended December 31, 1994, File No. 33-46795, on March 15, 1995).

*10.8 Lease Agreement between Old Dominion Electric Cooperative and Regional Headquarters, Inc., dated July 29, 1986 (filed as exhibit 10.27 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.9 Nuclear Decommissioning Trust Agreement between Old Dominion Electric Cooperative and Bankers Trust Company, dated March 1, 1991 (filed as exhibit 10.29 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.10 Form of Salary Continuation Plan (filed as exhibit 10.31 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.11 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and A&N Electric Cooperative, dated April 24, 1992 (filed as exhibit 10.34 to Amendment No. 2 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 27, 1992).

*10.12 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and BARC Electric Cooperative, dated April 22, 1992 (filed as exhibit 10.35 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.13 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Choptank Electric Cooperative, dated April 20, 1992 (filed as exhibit 10.36 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.14 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Community Electric Cooperative, dated April 28, 1992 (filed as exhibit 10.37 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.15 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Delaware Electric Cooperative, dated April 22, 1992 (filed as exhibit 10.38 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.16 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Mecklenburg Electric Cooperative, dated April 15, 1992 (filed as exhibit 10.39 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.17 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Northern Neck Electric Cooperative, dated April 21, 1992 (filed as exhibit 10.40 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.18 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Northern Virginia Electric Cooperative, dated April 17, 1992 (filed as exhibit 10.41 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.19 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Community Electric Cooperative, dated April 28, 1992 (filed as exhibit 10.37 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.20 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Delaware Electric Cooperative, dated April 22, 1992 (filed as exhibit 10.38 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.21 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Mecklenburg Electric Cooperative, dated April 15, 1992 (filed as exhibit 10.39 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.22 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Northern Neck Electric Cooperative, dated April 21, 1992 (filed as exhibit 10.40 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.23 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Northern Virginia Electric Cooperative, dated April 17, 1992 (filed as exhibit 10.41 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.24 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Prince George Electric Cooperative, dated May 6, 1992 (filed as exhibit 10.42 to Amendment No. 2 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 27, 1992).

*10.25 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Rappahannock Electric Cooperative, dated April 17, 1992 (filed as exhibit 10.43 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.26 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Shenandoah Valley Electric Cooperative, dated April 23, 1992 (filed as exhibit 10.44 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.27 Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and Southside Electric Cooperative, dated April 22, 1992 (filed as exhibit 10.45 to Amendment No. 1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on May 6, 1992).

*10.28 Interconnection Agreement between Delmarva Power & Light Company and Old Dominion Electric Cooperative, dated November 30, 1999 (filed as exhibit 10.33 to the Registrant's Form 10-K for the year ended December 31, 2000, File No. 33-46795, on March 19, 2001).

*10.29 Participation Agreement, dated as of February 29, 1996, among Old Dominion Electric Cooperative, State Street Bank and Trust Company, the Owner Participant named therein and Utrecht America Finance Co (filed as exhibit 10.35 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.30 Clover Unit 1 Equipment Interest Lease Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Equipment Head Lessor, and State Street Bank and Trust Company, as Equipment Head Lessee (filed as exhibit 10.36 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.31 Equipment Operating Lease Agreement, dated as of February 29, 1996, between State Street Bank and Trust Company, as Lessor, and Old Dominion Electric Cooperative, as Lessee (filed as exhibit 10.37 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.32 Corrected Option Agreement to Lease, dated as of February 29, 1996, among Old Dominion Electric Cooperative and State Street Bank and Trust Company (filed as exhibit 10.38 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.33 Clover Agreements Assignment and Assumption Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Assignor, and State Street Bank and Trust Company, as Assignee (filed as exhibit 10.39 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.34 Payment Undertaking Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative and Cooperatieve Centrale Raiffeisen Boerenleenbank B.A., "Rabobank Nederland", New York Branch (filed as exhibit 10.42 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.35 Payment Undertaking Pledge Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Payment Undertaking Pledgor, and State Street Bank and Trust Company, as Payment Undertaking Pledgee (filed as exhibit 10.43 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.36 Pledge Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Pledgor, and State Street Bank and Trust Company, as Pledgee (filed as exhibit 10.44 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.37 Tax Indemnity Agreement, dated as of February 29, 1996, among Old Dominion Electric Cooperative, State Street Bank and Trust Company, the Owner Participant named therein and Utrecht America Finance Co. (filed as exhibit 10.45 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.38 Participation Agreement, dated as of July 1, 1996, among Old Dominion Electric Cooperative, Clover Unit 2 Generating Trust, Wilmington Trust Company, the Owner Participant named therein and Utrecht America Finance Co. (filed as exhibit 10.46 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.39 Clover Unit 2 Equipment Interest Agreement, dated as of July 1, 1996, between Old Dominion Electric Cooperative and Clover Unit 2 Generating Trust (filed as exhibit 10.47 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

**10.40 Operating Equipment Agreement, dated as of July 1, 1996, between Clover Unit 2 Generating Trust and Old Dominion Electric Cooperative (filed as exhibit 10.48 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.41 Clover Agreements Assignment and Assumption Agreement, dated as of July 1, 1996, between Old Dominion Electric Cooperative, as Assignor, and Clover Unit 2 Generating Trust, as Assignee (filed as exhibit 10.49 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.42 Deed of Ground Lease and Sublease Agreement, dated as of July 1, 1996, between Old Dominion Electric Cooperative, as Ground Lessor, and Clover Unit 2 Generating Trust, as Ground Lessee (filed as exhibit 10.50 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.43 Guaranty Agreement, dated as of July 1, 1996, between Old Dominion Electric Cooperative and AMBAC Indemnity Corporation (filed as exhibit 10.51 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.44 Investment Agreement, dated as of July 31, 1996, among AMBAC Capital Funding, Inc., Old Dominion Electric Cooperative and AMBAC Indemnity Corporation (filed as exhibit 10.52 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.45 Investment Agreement Pledge Agreement, dated as of July 1, 1996, among Old Dominion Electric Cooperative, as Investment Agreement Pledgor, AMBAC Indemnity Corporation, the Owner Participant named therein and Clover Unit 2 Generating Trust (filed as exhibit 10.53 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.46 Equity Security Pledge Agreement, dated as of July 1, 1996, between Old Dominion Electric Cooperative, as Pledgor, and Wilmington Trust Company, as Collateral Agent (filed as exhibit 10.54 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.47 Payment Undertaking Agreement, dated as of July 1, 1996, between Old Dominion Electric Cooperative and Cooperatieve Centrale Raiffeisen Boerenleenbank B.A., "Rabobank Nederland", New York Branch (filed as exhibit 10.55 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.48 Payment Undertaking Pledge Agreement, dated as of July 1, 1996, between Old Dominion Electric Cooperative, as Payment Undertaking Pledgor, and Clover Unit 2 Generating Trust, as Payment Undertaking Pledgee (filed as exhibit 10.56 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.49 Subordinated Deed of Trust and Security Agreement, dated as of July 1, 1996, among Old Dominion Electric Cooperative, Richard W. Gregory, Trustee, and Michael P. Drzal, Trustee (filed as exhibit 10.57 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.50 Subordinated Security Agreement, dated as of July 1, 1996, among Old Dominion Electric Cooperative, the Owner Participant named therein, AMBAC Indemnity Corporation and Clover Unit 2 Generating Trust (filed as exhibit 10.58 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.51 Tax Indemnity Agreement, dated as of July 1 1996, between Old Dominion Electric Cooperative and the Owner Participant named therein (filed as exhibit 10.59 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*10.52 Amendment No. 3 to Participation Agreement (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*10.53 Amendment No. 2 to Equipment Operating Lease Agreement (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*10.54 Amendment No. 2 to Corrected Foundation Operating Lease Agreement (filed as Exhibit 10.3 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*10.55 Investment Agreement (filed as Exhibit 10.4 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*10.56 Investment Pledge Agreement (filed as Exhibit 10.5 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*10.57 Amendment No. 3 to Payment Undertaking Agreement (filed as Exhibit 10.6 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*10.58 Amendment No. 2 to Tax Indemnity Agreement (filed as Exhibit 10.7 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*10.59 Employment Agreement, dated June 1, 2006, between Old Dominion Electric Cooperative and Jackson E. Reasor and accepted by Jackson E. Reasor on December 18, 2006 (filed as Exhibit 10.1 to the Registrant's Form 8-K, File No. 000-50039, on December 21, 2006).

*10.60 Executive Deferred Compensation Plan, dated June 30, 2006, adopted on December 18, 2006 (filed as Exhibit 10.2 to the Registrant's Form 8-K File No. 000-50039, on December 21, 2006).

*10.61 Employment letter, dated November 28, 2005, of Old Dominion Electric Cooperative and agreed and accepted by Robert L. Kees (filed as exhibit 10.1 to the Registrant's Form 8-K, No. 000-50039, on November 28, 2005).

*10.62 Amendment No. 1 to Participation Agreement, dated as of December 19, 2002, among Old Dominion Electric Cooperative, State Street Bank and Trust Company, the Owner Participant named therein, Utrecht America Finance Co and Cedar Hill International Corp.

*10.63 Amendment No. 1 to Equipment Operating Lease Agreement, dated as of December 19, 2002, between State Street Bank and Trust Company, as Lessor, and Old Dominion Electric Cooperative, as Lessee.

*10.64 Amendment No. 1. to Corrected Foundation Operating Lease Agreement, dated as of December 19, 2002, between State Street Bank and Trust Company, as Foundation Lessor and Old Dominion Electric Cooperative, as Foundation Lessee.

*10.65 Amendment No. 2 to Payment Undertaking Agreement, dated as of December 19, 2002 between Old Dominion Electric Cooperative and Cooperatieve Centrale Raiffeisen Boerenleenbank B.A., "Rabobank Nederland", New York Branch.

*10.66 Amendment No. 1 to Tax Indemnity Agreement, dated as of December 19, 2002, between Old Dominion Electric Cooperative and the Owner Participant named therein.

*10.67 Amendment No. 2 to Participation Agreement, dated as of December 31, 2004, between and among Old Dominion Electric Cooperative, U.S. Bank National Association, Wachovia Bank, National Association, Utrecht-America Finance Co., and Cedar Hill International Corp. (filed as exhibit 10.1 to the Registrant's Form 8-K, File No. 000-50039, on January 13, 2005).

*10.68 Mutual Operating Agreement, dated as of May 18, 2005, between Virginia Electric and Power Company and Old Dominion Electric Cooperative.

21 Subsidiaries of Old Dominion Electric Cooperative (not included because Old Dominion Electric Cooperative's subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a "significant subsidiary" under Rule 102(w) of Regulation S-X).

23.1 Consent of Ernst & Young LLP

31.1 Certification of the Principal Executive Officer pursuant to Rule 13a-14(a)

31.2 Certification of the Principal Financial Officer pursuant to Rule 13a-14(a)

32.1 Certification of the Principal Executive Officer pursuant to 18 U.S.C. § 1350

32.2 Certification of the Principal Financial Officer pursuant to 18 U.S.C. § 1350

* Incorporated herein by reference.

** These leases relate to our interest in all of Clover Unit 1 and Clover Unit 2, as applicable, other than the foundations. At the time these leases were executed, we had entered into identical leases with respect to the foundations as part of the same transactions. We agree to furnish to the Commission, upon request, a copy of the leases of our interest in the foundations for Clover Unit 1 and Clover Unit 2, as applicable.

*** This agreement consists of two separate signed documents, which have been combined.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OLD DOMINION ELECTRIC COOPERATIVE
Registrant

By: /s/ JACKSON E. REASOR
Jackson E. Reasor
President and Chief Executive Officer

Date: March 20, 2007

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 following capacities on March 20, 2007.

Signature	Title
/s/ JACKSON E. REASOR Jackson E. Reasor	President and Chief Executive Officer (Principal executive officer)
/s/ ROBERT L. KEES Robert L. Kees	Senior Vice President and Chief Financial Officer (Principal financial officer and Principal accounting officer)
/s/ J. WILLIAM ANDREW, JR. J. William Andrew, Jr.	Director
/s/ M. JOHNSON BOWMAN M. Johnson Bowman	Director
/s/ M DALE BRADSHAW M Dale Bradshaw	Director
/s/ VERNON N. BRINKLEY Vernon N. Brinkley	Director
/s/ CALVIN P. CARTER Calvin P. Carter	Director
/s/ GLENN F. CHAPPELL Glenn F. Chappell	Director

/s/ KENT D. FARMER Kent D. Farmer	Director
/s/ STANLEY C. FEUERBERG Stanley C. Feuerberg	Director
/s/ WILLIAM C. FRAZIER William C. Frazier	Director
/s/ FRED C. GARBER Fred C. Garber	Director
/s/ HUNTER R. GREENLAW, JR. Hunter R. Greenlaw, Jr.	Director
/s/ BRUCE A. HENRY Bruce A. Henry	Director
/s/ WADE C. HOUSE Wade C. House	Director
/s/ FREDERICK L. HUBBARD Frederick L. Hubbard	Director
/s/ DAVID J. JONES David J. Jones	Director
/s/ BRUCE M. KING Bruce M. King	Director
/s/ WILLIAM M. LEECH, JR. William M. Leech, Jr.	Director
/s/ M. LARRY LONGSHORE M. Larry Longshore	Director
/s/ PAUL E. OWEN Paul E. Owen	Director

/s/ JAMES M. REYNOLDS James M. Reynolds	Director
/s/ MYRON D. RUMMEL Myron D. Rummel	Director
/s/ PHILIP B. TANKARD Philip B. Tankard	Director
/s/ GREGORY W. WHITE Gregory W. White	Director
/s/ CARL R. WIDDOWSON Carl R. Widdowson	Director

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement Form S-3 No. 33-10577 of Old Dominion Electric Cooperative and in the related Prospectus of our report dated March 14, 2007, with respect to the consolidated financial statements of Old Dominion Electric Cooperative included in this Annual Report (Form 10-K) for the year ended December 31, 2006.

/s/ Ernst & Young LLP

Richmond, VA
March 14, 2007

Exhibit 31.1

CERTIFICATIONS

I, Jackson E. Reasor, certify that:

1. I have reviewed this annual report on Form 10-K of Old Dominion Electric Cooperative;

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

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

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

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

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect the registrant's internal control over financial reporting;

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

(a) all significant deficiencies in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 20, 2007
/s/ JACKSON E. REASOR
Jackson E. Reasor
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, Robert L. Kees, certify that:

1. I have reviewed this annual report on Form 10-K of Old Dominion Electric Cooperative;

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

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

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

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

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   (c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect the registrant's internal control over financial reporting.

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

   (a) all significant deficiencies in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 20, 2007
/s/ ROBERT L. KEES
Robert L. Kees
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

Exhibit 32.1

OLD DOMINION ELECTRIC COOPERATIVE

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Old Dominion Electric Cooperative (the "Company") on Form 10-K for the period ending December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jackson E. Reasor, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: March 20, 2007

/s/JACKSON E. REASOR
Jackson E. Reasor
President and
Chief Executive Officer
(Principal executive officer)

Exhibit 32.2

OLD DOMINION ELECTRIC COOPERATIVE

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Old Dominion Electric Cooperative (the "Company") on Form 10-K for the period ending December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert L. Kees, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: March 20, 2007

/s/ROBERT L. KEES
Robert L. Kees
Senior Vice President and Chief Financial Officer
(Principal financial and accounting officer)

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(d) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT.

Old Dominion does not solicit proxies from its cooperative members and thus is not required to provide an annual report to its security holders and will not prepare such a report after filing this Form 10-K for fiscal year 2006. Accordingly, Old Dominion will not file an annual report with the Securities and Exchange Commission.

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

FORM 10-Q

(Mark One)

X QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2007

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 000-50039

OLD DOMINION ELECTRIC COOPERATIVE
(Exact Name of Registrant as Specified in Its Charter)

VIRGINIA (State or Other Jurisdiction of Incorporation or Organization)	23-7048405 (I.R.S. Employer Identification No.)
4201 Dominion Boulevard, Glen Allen, Virginia (Address of Principal Executive Offices)	23060 (Zip Code)

(804) 747-0592
(Registrant's Telephone Number, Including Area Code)

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 whether the Registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.
Larger accelerated filer _____ Accelerated filer _____ Non-accelerated filer X

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 Registrant is a membership corporation and has no authorized or outstanding equity securities

OLD DOMINION ELECTRIC COOPERATIVE

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OLD DOMINION ELECTRIC COOPERATIVE
PART 1. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2007	December 31, 2006
	(in thousands)	
ASSETS:	(unaudited)	
Electric Plant:		
In service	$ 1,524,067	$ 1,527,672
Less accumulated depreciation	(538,036)	(509,306)
	986,031	1,018,366
Nuclear fuel, at amortized cost	9,933	8,381
Construction work in progress	23,231	20,342
Net Electric Plant	1,019,195	1,047,089
Investments:		
Nuclear decommissioning trust	96,302	91,050
Lease deposits	178,183	171,585
Other	96,172	24,321
Total Investments	370,657	286,956
Current Assets:		
Cash and cash equivalents	105,064	52,018
Accounts receivable	5,915	4,071
Accounts receivable-deposits	-	23,600
Accounts receivable-members	92,147	94,136
Fuel, materials and supplies	30,642	30,585
Deferred energy	34,771	14,914
Prepayments	2,237	4,035
Total Current Assets	270,776	223,359
Deferred Charges:		
Regulatory assets	33,693	49,738
Other	17,758	20,267
Total Deferred Charges	51,451	70,005
Total Assets	$ 1,712,079	$ 1,627,409
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 304,270	$ 293,077
Non-controlling interest	11,066	10,993
Long-term debt	815,837	813,264
Total Capitalization	1,131,173	1,117,334
Current Liabilities:		
Long-term debt due within one year	22,917	22,917
Accounts payable	108,540	87,844
Accounts payable-members	64,160	48,220
Accrued expenses	60,433	35,767
Total Current Liabilities	256,050	194,748
Deferred Credits and Other Liabilities:		
Asset retirement obligation	58,010	55,812
Obligations under long-term leases	180,661	174,205
Regulatory liabilities	54,478	51,497
Other	31,707	33,813
Total Deferred Credits and Other Liabilities	324,856	315,327
Commitments and Contingencies	-	-
Total Capitalization and Liabilities	$ 1,712,079	$ 1,627,409

The accompanying notes are an integral part of the condensed consolidated financial statements.

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF REVENUES, EXPENSES AND PATRONAGE CAPITAL (UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Operating Revenues	$ 262,362	$ 221,231	$ 717,691	$ 610,644
Operating Expenses:				
Fuel	57,649	65,636	120,166	120,936
Purchased power	167,647	109,675	473,103	359,796
Deferred energy	(12,951)	339	(19,857)	(8,395)
Operations and maintenance	11,235	8,459	34,172	26,097
Administrative and general	8,811	7,530	25,424	24,879
Depreciation, amortization and decommissioning	9,365	9,628	28,189	28,922
Amortization of regulatory asset/(liability), net	624	444	1,517	1,137
Accretion of asset retirement obligations	732	651	2,197	1,953
Taxes other than income taxes	1,923	2,245	5,557	5,358
Total Operating Expenses	245,035	204,607	670,468	560,683
Operating Margin	17,327	16,624	47,223	49,961
Other Expense, net	(40)	(16)	(101)	(84)
Investment Income	3,886	2,243	10,519	6,413
Interest Charges, net	(15,496)	(15,306)	(45,783)	(45,376)
Net Margin Before Income Taxes and Non-Controlling Interest	5,677	3,545	11,858	10,914
Income Taxes	(132)	(182)	(157)	(720)
Non-Controlling Interest	(442)	(274)	(508)	(1,080)
Net Margin	5,103	3,089	11,193	9,114
Patronage Capital - Beginning of Period	299,167	277,858	293,077	271,833
Patronage Capital - End of Period	$ 304,270	$ 280,947	$ 304,270	$ 280,947

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Net Margin	$ 5,103	$ 3,089	$ 11,193	$ 9,114
Other Comprehensive Income:				
Unrealized loss on derivative contracts [(1)]	-	(467)	(435)	(14,307)
Other Comprehensive Income Before Non-Controlling Interest	-	2,622	10,758	(5,193)
Less: Non-controlling interest in comprehensive income	-	467	435	14,307
Comprehensive Income	$ 5,103	$ 3,089	$ 11,193	$ 9,114

[(1)] Unrealized loss on derivative contracts net of taxes of \$0.3 million for the nine months ended September 30, 2007. Unrealized loss on derivative contracts net of taxes of \$0.3 million and \$9.1 million for the three and nine months ended September 30, 2006, respectively.

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands)	
Operating Activities:		
Net Margin	$ 11,193	$ 9,114
Adjustments to reconcile net margins to net cash provided by (used for) operating activities:		
Depreciation, amortization and decommissioning	28,189	28,922
Other non-cash charges	8,997	8,852
Non-controlling interest	508	1,080
Amortization of lease obligations	8,684	8,218
Interest on lease deposits	(8,460)	(7,965)
Change in current assets	25,486	30,360
Change in deferred energy	(19,857)	(8,395)
Change in current liabilities	67,279	(29,811)
Change in regulatory assets and liabilities	17,499	(56,090)
Deferred charges and credits	1,763	12,052
Net Cash Provided by/(Used for) Operating Activities	141,281	(3,663)
Financing Activities:		
Obligations under long-term leases	(366)	(595)
Net Cash Used for Financing Activities	(366)	(595)
Investing Activities:		
Purchases of available for sale securities	(266,147)	(57,650)
Proceeds from sale of available for sale securities	176,779	21,975
Decrease (Increase) in other investments	13,793	(2,800)
Electric plant additions	(15,294)	(9,512)
Settlement of litigation	3,000	-
Net Cash (Used for)/Provided by Investing Activities	(87,869)	(47,987)
Net Change in Cash and Cash Equivalents	53,046	(52,245)
Cash and Cash Equivalents - Beginning of Period	52,018	98,633
Cash and Cash Equivalents - End of Period	$ 105,064	$ 46,388

The accompanying notes are an integral part of the condensed consolidated financial statements.

OLD DOMINION ELECTRIC COOPERATIVE

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. In the opinion of our management, the accompanying unaudited condensed consolidated financial statements contain all adjustments, which include only normal recurring adjustments, necessary for a fair statement of our consolidated financial position as of September 30, 2007, and our consolidated results of operations, comprehensive income, and cash flows for the three and nine months ended September 30, 2007 and 2006. The consolidated results of operations for the three and nine months ended September 30, 2007, are not necessarily indicative of the results to be expected for the entire year. These financial statements should be read in conjunction with the financial statements and notes thereto included in our 2006 Annual Report on Form 10-K filed with the Securities and Exchange Commission.

2. *Presentation.* The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative ("ODEC " or "we" or "our") and TEC Trading, Inc. ("TEC"). We are a not-for-profit wholesale power supply cooperative, incorporated under the laws of the Commonwealth of Virginia in 1948. We have two classes of members. Our Class A members are twelve customer-owned electric distribution cooperatives engaged in the retail sale of power to member consumers located in Virginia, Delaware, Maryland, and parts of West Virginia. Our sole Class B member is TEC, a taxable corporation owned by our member distribution cooperatives. Our board of directors is composed of two representatives from each of the member distribution cooperatives and one representative from TEC.

   In accordance with Financial Accounting Standards Board ("FASB") Interpretation No. 46R, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51" (the "Interpretation"), TEC is considered a variable interest entity for which we are the primary beneficiary. We have eliminated all intercompany balances and transactions in consolidation. The assets and liabilities and non-controlling interest of TEC are recorded at carrying value and the net assets consolidated were \$11.1 million and \$11.0 million at September 30, 2007, and December 31, 2006, respectively. As TEC is 100% owned by our twelve member distribution cooperatives, its equity is presented as a non-controlling interest in our consolidated financial statements. Our non-controlling, 50% or less, ownership interest in other entities is recorded using the equity method of accounting.

   Our rates are not regulated by the respective states' public service commissions, but are set periodically by a formula that was accepted for filing by the Federal Energy Regulatory Commission ("FERC") on December 23, 2003. An amendment to the formula was accepted for filing by FERC on February 19, 2005, subject to the outcome of our other pending FERC proceedings.

   We comply with the Uniform System of Accounts as prescribed by FERC. In conformity with accounting principles generally accepted in the United States ("GAAP"), the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes.

   The preparation of our consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported therein. Actual results could differ from those estimates.

3. *Financial Instruments (including Derivatives).* Financial instruments included in the decommissioning fund are classified as available for sale, and accordingly, are carried at fair value. Unrealized gains and losses on investments held in the decommissioning fund are deferred as a regulatory liability and a regulatory asset until realized.

   Our investments in marketable securities, which are actively managed, are classified as available for sale and are recorded at fair value. Unrealized gains or losses on these investments, if material, are reflected as a component of capitalization. Investments in debt securities that we have the positive intent and ability to hold to maturity are classified as held to maturity and are recorded at amortized cost. Other investments are recorded at cost, which approximates market value.

   We primarily purchase power under both long-term and short-term forward physical delivery contracts to supply power to our member distribution cooperatives under "all requirements" wholesale power contracts. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of the forward purchase derivative contracts qualify for the normal purchases/normal sales exception under Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities." As a result, these contracts are not recorded at fair value. We record a liability and purchased power expense when the power under the forward physical delivery contract is delivered. We also purchase natural gas futures generally for three years or less to hedge the price of natural gas for the operation of our combustion turbine facilities and to hedge certain forward power purchase agreements that use natural gas as a basis for determining the price of power. These derivatives do not qualify for the normal purchase/normal sales exception.

For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we may elect cash flow hedge accounting in accordance with SFAS No. 133. Accordingly, gains and losses on derivative contracts are deferred into Other Comprehensive Income until the hedged underlying transaction occurs or is no longer likely to occur. For derivative contracts where hedge accounting is not utilized, or for which ineffectiveness exists, we defer all remaining gains and losses on a net basis as a regulatory asset or liability in accordance with SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation." These amounts are subsequently reclassified as purchased power or fuel expense in our Consolidated Statements of Revenues, Expenses and Patronage Capital as the power or fuel is delivered and/or the contract settles.

Generally, derivatives are reported on the Consolidated Balance Sheet at fair value. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications. For individual contracts, the use of differing assumptions could have a material effect on the contract's estimated fair value. There was no hedge ineffectiveness for the three and nine months ended September 30, 2007. Hedge ineffectiveness was immaterial for the three and nine month ended September 30, 2006.

We are exposed to credit risk in our business operations. We have a Credit Risk Policy that establishes the basis for determining counterparty credit standards and processes to determine credit limits. Our risk management committee monitors credit exposure on a regular basis. Formal counterparty credit reviews are performed at least annually and informal reviews are performed on an ongoing basis

4. *Commitments and Contingencies.*

Norfolk Southern

In April 1989, we entered into a coal transportation agreement with Norfolk Southern Railway Company ("Norfolk Southern") for delivery of coal to the Clover Power Station ("Clover"). The agreement, which was later assigned to Virginia Electric & Power Company ("Virginia Power") as operator of Clover, had an initial 20-year term and provides that the amounts payable for coal transportation services are subject to adjustment based on a reference index. In October 2003, Norfolk Southern claimed that it had been using an incorrect reference index to calculate amounts due to it since the inception of the agreement, and that it would begin to escalate prices for these services in the future based on an alternate reference index. On November 26, 2003, together with Virginia Power, we filed suit against Norfolk Southern in the Circuit Court of Halifax County, Virginia, seeking an order to clarify the price escalation provisions in the coal transportation agreement. In its reply to our suit, Norfolk Southern filed a counter-claim and sought (1) recovery from Virginia Power and us for additional amounts resulting from its use of the alternate reference index since December 1, 2003, and (2) an order requiring the parties to calculate the amounts Norfolk Southern claims it was underpaid since the inception of the agreement by using the alternate reference index.

On December 22, 2004, the court found in favor of Norfolk Southern on the issue of ambiguity and held that the price escalation provisions in the agreement were clear and unambiguous. The court later denied Virginia Power's and our motion to file an amended complaint based on additional evidence that was not considered by the court in the original proceedings. The court permitted Virginia Power and us to file an amended answer to Norfolk Southern's counter-claims and our amended answer was filed on March 4, 2005.

On September 1, 2006, the court granted Norfolk Southern's request to substantially dispose of the issues in the case. On September 23, 2006, we, along with Virginia Power, appealed the court's order to the Supreme Court of Virginia. On December 13, 2006, Norfolk Southern filed a motion to dismiss for lack of jurisdiction, contending that we and Virginia Power failed to timely appeal. On April 4, 2007, we, along with Virginia Power, presented our arguments to a panel of three justices as to why the petition for appeal should be granted.

On May 11, 2007, the Supreme Court of Virginia dismissed Norfolk Southern's motion to dismiss for lack of jurisdiction and dismissed our petition for appeal because there is not a final appealable order. The case was returned to the Circuit Court of Halifax County, Virginia. On June 11, 2007, we, along with Virginia Power, filed a motion to vacate the order and schedule a status conference. On June 26, 2007, Norfolk Southern filed a motion for a status conference and a brief in opposition to our motion to vacate the order. We are currently awaiting the court's decision.

We recorded a liability related to the Norfolk Southern dispute and created a related regulatory asset for prior charges. The regulatory asset was amortized over 21 months (April 1, 2005 through December 31, 2006) and was fully amortized and collected through rates as of December 31, 2006. The current period charges are being collected through rates. If it is ultimately determined that we owe any such amounts to Norfolk Southern, the amounts are not expected to have a material impact on our financial position or results of operations due to our ability to collect such amounts through rates charged to our member distribution cooperatives.

Ragnar Benson

In December 2002, we entered into a contract with Ragnar Benson, Inc. ("RBI") for engineering, procurement and construction services relating to the construction of our Marsh Run combustion turbine facility. On December 23, 2004, we terminated the contract with RBI for default and filed suit in the U.S. District Court for the Eastern District of Virginia, Richmond Division, against RBI. On June 13, 2005, we executed an agreement with RBI's surety, Seaboard Surety Company ("Seaboard"), under which it assumed all responsibilities for the final completion of the Marsh Run facility in accordance with the terms of the original agreement with RBI. RBI and its parent companies, The Austin Company and Austin Holdings, Inc., filed for reorganization on October 14, 2005. Because RBI filed for reorganization during the legal proceeding, we served a lawsuit against Seaboard on February 10, 2006, in order to enforce the eventual outcome of the suit with RBI. On August 23, 2007, we settled our legal disputes with Seaboard. In full settlement of our legal disputes with Seaboard, we received a payment of $3.0 million from Seaboard and we were released of any and all remaining payment obligations. At the time of the settlement we had a $5.7 million liability recorded which was reversed based on the terms of the settlement. The $8.7 million impact of the settlement resulted in a reduction of the cost of our Marsh Run facility. The terms of our agreement provided for the assignment by ODEC to Seaboard of all of ODEC's rights and claims against RBI in the current reorganization proceedings including the judgment obtained against RBI, and Seaboard and ODEC each released the other from any and all claims arising out of or related to the Marsh Run Project.

5. *New Accounting Pronouncements.*

   We adopted the provisions of the Financial Accounting Standards Board ("FASB") Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109" ("FIN 48") on January 1, 2007. This interpretation requires that income tax positions recognized in an entity's tax returns have a more-likely-than-not chance of being sustained prior to recording the related tax benefit in the financial statements. There was no impact on our financial statements as a result of the adoption of FIN 48.

   In September 2006, the FASB issued Statement No. 157, "Fair Value Measurements" ("SFAS No. 157"). SFAS No. 157 clarifies that the term fair value is intended to mean a market-based measure, not an entity-specific measure and gives the highest priority to quoted prices in active markets in determining fair value. SFAS No. 157 requires disclosures about the extent to which companies measure assets and liabilities at fair value, the methods and assumptions used to measure fair value, and the effect of fair value measures on earnings. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact that SFAS No. 157 may have on our financial statements.

6. *Equity Contribution.*

   As approved by our board of directors on July 23, 2007, our net margins include $2.0 million of equity contribution.

7. *Subsequent Event.*

   On October 10, 2007, our Board of Directors approved an increase to our fuel factor adjustment rate, resulting in an increase to our total energy rate of approximately 1.7%, effective October 1, 2007. This increase was implemented due to continued increases in our energy costs and to collect a portion of our deferred energy balance. On October 10, 2007 our Board of Directors also approved the refund of $11.0 million related to our margin stabilization plan, which will be refunded during the fourth quarter of 2007.

OLD DOMINION ELECTRIC COOPERATIVE

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Caution Regarding Forward-Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements regarding matters that could have an impact on our business, financial condition, and future operations. These statements, based on our expectations and estimates, are not guarantees of future performance and are subject to risks, uncertainties, and other factors that could cause actual results to differ materially from those expressed in the forward-looking statements. These risks, uncertainties, and other factors include, but are not limited to, general business conditions, increased competition in the electric utility industry, changes in our tax status, demand for energy, federal and state legislative and regulatory actions, and legal and administrative proceedings, changes in and compliance with environmental laws and policies, weather conditions, the cost of commodities used in our industry, and unanticipated changes in operating expenses and capital expenditures. Our actual results may vary materially from those discussed in the forward-looking statements as a result of these and other factors. Any forward-looking statement speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which the statement is made even if new information becomes available or other events occur in the future.

Critical Accounting Policies

As of September 30, 2007, there have been no significant changes in our critical accounting policies as disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006. The policies included the accounting for rate regulation, deferred energy, asset retirement obligations, derivative contracts and our margin stabilization plan.

Basis of Presentation

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative ("ODEC" or "we" or "our") and TEC Trading, Inc. ("TEC"). See Note 2—Notes to Condensed Consolidated Financial Statements in Part 1, Item 1.

Overview

ODEC is a not-for-profit power supply cooperative owned entirely by its twelve member distribution cooperatives and a thirteenth member, TEC. We supply our member distribution cooperatives' power requirements, consisting of capacity requirements and energy requirements through a portfolio of resources including generating facilities, long-term and short-term physically-delivered forward power purchase contracts, and spot market purchases.

Our financial results for the three and nine months ended September 30, 2007, were impacted by higher energy rates, the availability of our generation facilities, and changes in the fair value of our derivatives. Revenues were higher due to increased sales volume and higher energy rates, which were implemented in October of 2006 and April of 2007 to collect previously incurred but not collected costs and to provide for the collection of future anticipated costs. During the three months ended September 30, 2007, North Anna Power Station ("North Anna") Unit 1 was off-line for a scheduled refueling and maintenance outage. During the nine months ended September 30, 2007, both units at the Clover Power Station ("Clover") were off-line for scheduled maintenance outages and both units at North Anna were off-line for scheduled refueling and maintenance outages. These outages resulted in increased purchased power expense as well as operations and maintenance expenses. Our operating expenses are significantly affected by the extent to which we purchase power and, relatedly, the availability of our base load generating facilities, Clover and North Anna. The fair value of our natural gas futures increased resulting in changes to our regulatory assets and liabilities which increased cash provided by operating activities.

We have a Margin Stabilization Plan that allows us to review our actual capacity-related costs of service and capacity revenue and adjust revenues from our member distribution cooperatives to meet our financial coverage requirements and accumulate additional equity as approved by our board of directors. Our formulary rate allows us to recover and refund amounts under the Margin Stabilization Plan. Each quarter we adjust revenues and accounts payable—members or accounts receivable, as appropriate, to reflect these adjustments. During the three months ended September 30, 2007, we refunded $6.0 million to our member distribution cooperatives related to our margin stabilization plan as approved by our board of directors on July 23, 2007.

Results of Operations

Operating Revenues

Our power sales are comprised of two power products – energy and capacity (also referred to as demand). Energy is the physical electricity delivered through transmission and distribution facilities to customers. We must have sufficient committed energy available to us for delivery to our member distribution cooperatives to meet their maximum energy needs at any time, with limited exceptions. This committed available energy at any time is referred to as capacity.

The rates we charge our member distribution cooperatives for sales of energy and capacity are determined by a formulary rate accepted by the Federal Energy Regulatory Commission ("FERC"), which is intended to permit collection of revenues which will equal the sum of:

- all of our costs and expenses;
- 20% of our total interest charges; and
- additional equity contributions approved by our board of directors.

The formulary rate has three main components: a demand rate, a base energy rate and a fuel factor adjustment rate. The formulary rate identifies the cost components that we can collect through rates, but not the actual amounts to be collected. With limited exceptions, we can change our rates periodically to match the costs we have incurred and we expect to incur without seeking FERC approval.

Energy costs, which are primarily variable costs, such as nuclear, coal and natural gas fuel costs and the energy costs under our power purchase contracts with third parties, are recovered through two separate energy rates, the base energy rate and the fuel factor adjustment rate. The base energy rate is a fixed rate that requires FERC approval prior to adjustment. However, to the extent the base energy rate over- or under-collects all of our energy costs, we refund or collect the difference through a fuel factor adjustment rate. We review our energy costs at least every six months to determine whether the base energy rate and the current fuel factor adjustment rate together are adequately recovering our actual and anticipated energy costs, and revise the fuel factor adjustment rate accordingly. Since the fuel factor adjustment rate can be revised without FERC approval, we can effectively change our total energy rate to recover all of our energy costs without seeking the approval of FERC.

Capacity costs, which are primarily fixed costs, such as depreciation expense, interest expense, administrative and general expenses, capacity costs under our power purchase contracts with third parties, transmission costs, and our margin requirements and additional amounts approved by our board of directors are recovered through our demand rate. The formulary rate allows us to change the actual demand rate we charge as our capacity-related costs change, without seeking FERC approval, with the exception of decommissioning cost, which is a fixed number in the formulary rate that requires FERC approval prior to any adjustment. FERC approval is also needed to change account classifications currently in the formula or to add accounts not otherwise included in the current formula. Additionally, future depreciation studies are to be filed with FERC for their approval if they would result in a change in our deprecation rates. Our demand rate is revised automatically to recover the costs contained in our budget and any revisions made by our board of directors to our budget.

Our operating revenues are derived from power sales to our member distribution cooperatives and non-members. Our operating revenues by type of purchaser for the three and nine months ended September 30, 2007 and 2006, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Revenues from sales to:				
Member distribution cooperatives	$ 237,855	$ 201,620	$ 645,910	$ 550,217
Non-members	24,507	19,611	71,781	60,427
Total revenues	$ 262,362	$ 221,231	$ 717,691	$ 610,644

Our energy sales in megawatt hours ("MWh") to our member distribution cooperatives and non-members for the three months and nine months ended September 30, 2007 and 2006, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30.	
	2007	2006	2007	2006
	(in MWh)		(in MWh)	
Energy sales to:				
Member distribution cooperatives	3,256,837	3,122,086	9,001,847	8,366,995
Non-members	443,453	290,740	1,377,592	1,049,175
Total energy sales	3,700,290	3,412,826	10,379,439	9,416,170

Sales to Member Distribution Cooperatives. Revenues from sales to our member distribution cooperatives are a function of our formulary rate for sales of power to our member distribution cooperatives and our member distribution cooperatives' consumers' requirements for power. Operating revenues on our Condensed Consolidated Statements of Revenues, Expenses and Patronage Capital reflect the actual capacity-related costs we incurred plus the energy costs that we collected during the period. Estimated capacity-related costs are collected during the period through the demand component of our formulary rate. Under our formulary rate, we make adjustments for the refund or recovery of amounts under our Margin Stabilization Plan. We adjust demand revenues and accounts payable—members or accounts receivable—members each quarter to reflect these adjustments. During the three months ended September 30, 2007, we refunded $6.0 million to our member distribution cooperatives related to our margin stabilization plan as approved by our board of directors on July 23, 2007. See "Critical Accounting Policies—Margin Stabilization Plan" in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2006, for a discussion of our Margin Stabilization Plan.

Revenues from sales to our member distribution cooperatives by formulary rate component and average costs to our member distribution cooperatives in MWh for the three and nine months ended September 30, 2007 and 2006 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30.	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Revenues from sales to member distribution cooperatives:				
Base energy revenues	$ 58,459	$ 56,120	$161,959	$150,480
Fuel factor adjustment revenues	115,835	92,109	308,784	232,707
Total energy revenues	174,294	148,229	470,743	383,187
Demand (capacity) revenues	63,561	53,391	175,167	167,030
Total revenues from sales to member distribution cooperatives	$237,855	$201,620	$645,910	$550,217
Average costs to member distribution cooperatives (per MWh)	$ 73.03	$ 64.58	$ 71.75	$ 65.76

Growth in the number of consumers and growth in consumers' requirements for power significantly affect our member distribution cooperatives' requirements for power. Factors affecting our member distribution cooperatives' consumers' requirements for power include the amount, size, and usage of electronics and machinery and the expansion of operations among their commercial and industrial customers. Weather also affects the requirement for electricity. Relatively higher or lower temperatures tend to increase the requirement for energy to use air conditioning and heating systems. Mild weather generally reduces the requirement because air conditioning and heating systems are operated less.

Three and Nine months Ended September 30, 2007 compared to Three and Nine months ended September 30, 2006:

Total revenues from sales to our member distribution cooperatives for the three and nine months ended September 30, 2007, increased $36.2 million, or 18.0%, and increased $95.7 million, or 17.4%, respectively as compared to the same periods in 2006 primarily as a result of our higher energy rate and increased sales volume.

Our total energy rate (including our base energy rate and our fuel factor adjustment rate) was 12.7% and 14.2% higher during the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. We increased our fuel factor adjustment rate effective October 1, 2006, and April 1, 2007, resulting in an increase to our total energy rate of approximately 5.2% and 7.2%, respectively. These increases were implemented due to our continued rising fuel and purchased power costs and differences between actual costs incurred and anticipated costs upon which our rates were based. Our energy sales volume to our member distribution cooperatives increased 4.3% and 7.6% for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006 as a result of increased requirements for power by our member distribution cooperatives.

The capacity costs we incurred, and thus the capacity-related revenues we reflected pursuant to the formulary rate, for the three and nine months ended September 30, 2007, increased $10.2 million, or 19.0%, and $8.1 million, or 4.9%, respectively, as compared to the same periods in 2006. The increase in capacity costs related primarily to an increase in purchased capacity costs.

Our average costs to member distribution cooperatives per MWh increased $8.45, or 13.1%, and $5.99, or 9.1%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006, as a result of the increase in our total energy rates primarily related to our increased purchased power costs.

Sales to Non-Members. Sales to non-members consist of sales of excess purchased energy and sales of excess generated energy. We primarily sell excess energy to PJM Interconnection, LLC. ("PJM") under its rates for providing energy imbalance services. Non-member revenue increased by $4.9 million, or 25.0%, and $11.4, or 18.8%, in the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. The increase in non-member revenue is primarily due to an increase in the volume of excess energy sales. The volume of excess energy sales increased 52.5% and 31.3% for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. Excess energy results from changes in our purchased power portfolio, differences between actual and forecasted energy needs, as well as changes in market conditions.

Operating Expenses

We supply our member distribution cooperatives' power requirements, consisting of capacity requirements and energy requirements, through (i) our interests in electric generating facilities which consist of a 50% interest in Clover, an 11.6% interest in North Anna, our Louisa combustion turbine facility ("Louisa"), our Marsh Run combustion turbine facility ("Marsh Run"), our Rock Springs combustion turbine facility ("Rock Springs"), and our distributed generation facilities, and (ii) power purchases from third parties through power purchase contracts and forward, short-term and spot market energy purchases. Our energy supply for the three and nine months ended September 30, 2007 and 2006, was as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2007		2006		2007		2006	
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	855,394	23.0 %	861,235	24.8 %	2,475,009	23.5 %	2,598,499	27.1 %
North Anna	389,675	10.5	469,832	13.6	1,209,251	11.4	1,298,083	13.5
Louisa	150,743	4.1	175,565	5.1	190,543	1.8	205,249	2.1
Marsh Run	181,723	4.9	188,726	5.4	249,212	2.4	221,420	2.3
Rock Springs	28,482	0.8	48,968	1.4	45,014	0.4	53,377	0.6
Distributed generation	489	-	606	-	646	-	711	-
Total generated	1,606,506	43.3	1,744,932	50.3	4,169,675	39.5	4,377,339	45.6
Purchased:								
Total purchased	2,101,477	56.7	1,725,499	49.7	6,377,778	60.5	5,219,015	54.4
Total available energy	3,707,983	100.0 %	3,470,431	100.0 %	10,547,453	100.0 %	9,596,354	100.0 %

We meet the majority of our member distribution cooperatives' capacity requirements and a portion of their energy requirements through our ownership interests in Clover, North Anna, Louisa, Marsh Run, and Rock Springs. We purchase capacity and energy from the market to supply the remaining needs of our member distribution cooperatives.

Our operating expenses are significantly affected by the extent to which we purchase power and, relatedly, the availability of our base load generating facilities, Clover and North Anna. Base load generating facilities, particularly nuclear power plants such as North Anna, generally have relatively high fixed costs, but nuclear facilities operate with relatively low variable costs due to lower fuel costs and technological efficiencies. In addition, coal-fired facilities also have relatively low variable costs, as compared to combustion turbine facilities such as Louisa, Marsh Run and Rock Springs. Owners of nuclear and other power plants incur the embedded fixed costs of these facilities whether or not the units operate. When either Clover or North Anna is off-line, we must purchase replacement energy from either Virginia Electric & Power Company ("Virginia Power") or from the market. As a result, our operating expenses, and consequently our rates to our member distribution cooperatives, are more significantly affected by the operations of Clover and North Anna than by our combustion turbine facilities. Our combustion turbine facilities have relatively low fixed costs and greater operational flexibility, but are more expensive to operate; therefore, we operate them only when the market price of energy makes their operation economical or when their operation is required by PJM for system reliability purposes. The output of Clover and North Anna for the three and nine months ended September 30, 2007 and 2006, as a percentage of the maximum net dependable capacity rating of the facilities was as follows:

	Clover				**North Anna**			
	Three Months Ended September 30,		**Nine Months Ended September 30,**		**Three Months Ended September 30,**		**Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**	**2006**
Unit 1	88.2 %	90.3 %	86.4 %	91.3 %	74.8 %	99.9 %	91.4 %	86.1 %
Unit 2	93.0	89.1	87.4	91.0	90.8	99.5	82.0	100.0
Combined	90.6	89.7	86.9	91.2	82.8	99.7	86.7	93.1

Clover. During the nine months ended September 30, 2007, Clover Units 1 and 2 were off-line for 14 days and 13 days, respectively, for scheduled maintenance outages. During the nine months ended September 30, 2006, Clover Units 1 and 2 were each off-line for five days for scheduled maintenance outages. Clover Units 1 and 2 experienced minor unscheduled outages for the three and nine months ended September 30, 2007 and 2006.

North Anna. On September 9, 2007, North Anna Unit 1 was taken off-line for a scheduled refueling and maintenance outage and was returned to service on October 15, 2007. On March 18, 2007, North Anna Unit 2 was taken off-line for a scheduled refueling and maintenance outage and was returned to service on April 22, 2007. North Anna Units 1 and 2 experienced unscheduled outages during the nine months ended September 30, 2007. During the nine months ended September 30, 2006, North Anna Unit 1 was off-line for 29 days for a scheduled refueling and maintenance outage. North Anna Unit 1 experienced minor unscheduled outages during the nine months ended September 30, 2006. North Anna Unit 2 did not experience any outages during the nine months ended September 30, 2006.

Combustion turbine facilities. During the three and nine months ended September 30, 2007 and 2006, the operational availability of Louisa, Marsh Run and Rock Springs was as follows:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
Louisa	99.0 %	99.5 %	95.7 %	99.6 %
Marsh Run	100.0	99.5	98.7	99.6
Rock Springs	99.9	100.0	99.2	93.2

The components of our operating expenses for the three and nine months ended September 30, 2007 and 2006, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Fuel	$ 57,649	$ 65,636	$ 120,166	$ 120,936
Purchased power	167,647	109,675	473,103	359,796
Deferred energy	(12,951)	339	(19,857)	(8,395)
Operations and maintenance	11,235	8,459	34,172	26,097
Administrative and general	8,811	7,530	25,424	24,879
Depreciation, amortization and decommissioning	9,365	9,628	28,189	28,922
Amortization of regulatory asset/(liability), net	624	444	1,517	1,137
Accretion of asset retirement obligations	732	651	2,197	1,953
Taxes other than income taxes	1,923	2,245	5,557	5,358
Total Operating Expenses	$ 245,035	$ 204,607	$ 670,468	$ 560,683

Aggregate operating expenses increased $40.4 million, or 19.8%, and $109.8 million, or 19.6%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006, primarily due to changes in purchased power expense, deferred energy, and operations and maintenance expense. For the three months ended September 30, 2007, the increase in operating expenses was slightly offset by a decrease in fuel expense.

Purchased power expense increased $58.0 million, or 52.9%, and $113.3 million, or 31.5%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006, due to an increase in the volume of purchased power and an increase in the average cost of purchased power. For the three and nine months ended September 30, 2007, the volume of purchased power increased 21.8% and 22.2%, respectively, and the average cost of purchased power increased 25.5% and 7.6%, respectively, as compared to the same periods in 2006. During a portion of the nine months ended September 30, 2007, our Clover and North Anna units were not available due to scheduled maintenance and refueling outages; which increased our volume of purchased power. The volume of purchased power also increased due to the increased requirements of our member distribution cooperatives. The increase in the average cost of purchased power is reflective of the timing of our forward purchases relative to the prevailing market prices at the time of those purchases.

Deferred energy expense changed $13.3 million, and $11.5 million, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. During the three months ended September 30, 2007, we under-collected $13.0 million in energy costs; whereas in the three months ended September 30, 2006, we over-collected $0.3 million in energy costs. During the nine months ended September 30, 2007, we under-collected $19.9 million in energy costs as compared to an under-collection of $8.4 million for the same period in 2006. At September 30, 2007 and 2006, we had an under-collected deferred energy balance of $34.8 million and $29.7 million, respectively.

Operations and maintenance expense increased $2.8 million, or 32.8%, and $8.1 million, or 30.9%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. The increase in operations and maintenance expense was primarily related to the scheduled maintenance outages at Clover and North Anna.

Fuel expense decreased $8.0 million, or 12.2%, for the three months ended September 30, 2007, as compared to the same period in 2006. The decrease in fuel expense is primarily related to decreased fuel consumption due to the reduction in dispatch of our combustion turbine facilities in the three months ended September 30, 2007, as compared to the same period in 2006. Fuel expense was relatively flat for the nine months ended September 30, 2007, as compared to the same period in 2006.

Other Items

Investment Income. Investment income increased $1.6 million, or 73.3%, and $4.1 million, or 64.0%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006, primarily due to income earned on our increased average balances in cash and temporary investments.

Interest Charges, net. The primary factors affecting our interest expense are scheduled payments of principal on our indebtedness and interest related to our potential liability associated with our dispute with Norfolk Southern Railway Company ("Norfolk Southern").

The major components of interest charges, net for the three and nine months ended September 30, 2007 and 2006, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(in thousands)		**(in thousands)**	
Interest expense on long-term debt	$ (13,622)	$ (13,880)	$ (40,858)	$ (41,749)
Other	(1,896)	(1,563)	(5,110)	(3,818)
Total Interest Charges	(15,518)	(15,443)	(45,968)	(45,567)
Allowance for borrowed funds used during construction	22	137	185	191
Interest Charges, net	$ (15,496)	$ (15,306)	$ (45,783)	$ (45,376)

Interest charges, net remained relatively flat for the three and nine months ended September 30, 2007, as compared to the same periods in 2006. Other interest expense increased $0.3 million, or 21.3% and $1.3 million, or 33.8%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006, primarily as a result of accrued interest related to our dispute with Norfolk Southern.

Net Margin. Our net margin, which is a function of our total interest charges plus any additional equity contributions approved by our board of directors, increased $2.0 million, or 65.2%, and $2.1 million, or 22.8%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. The increase is the result of an additional equity contribution of $2.0 million during the three months ended September 30, 2007.

Financial Condition

The principal changes in our financial condition from December 31, 2006 to September 30, 2007, were caused by increases in investments—other, accrued expenses, accounts payable, deferred energy and accounts payable—members, partially offset by decreases in accounts receivable—deposits, and regulatory assets. Investments—other increased $71.9 million related to the return of $23.6 million in collateral we were required to post with our counterparties at December 31, 2006, additional cash invested due to our margin stabilization balance and cash provided by operations. Accrued expenses increased $24.7 million primarily related to accrued interest and accrued transportation costs related to our dispute with Norfolk Southern. Accounts payable increased $20.7 million primarily as a result of increased purchased power invoices. Deferred energy increased $19.9 million as a result of the under-collection of our energy costs. Accounts payable—members increased $15.9 million primarily as a result of an increased margin stabilization adjustment in 2007 as compared to the same period in 2006 slightly offset by a reduction in member prepayments. Accounts receivable—deposits decreased $23.6 million related to the return to us of collateral posted as of December 31, 2006, due to changes in energy prices. Regulatory assets decreased $16.0 million primarily due to the change in the fair value of our derivatives.

Liquidity and Capital Resources

Operations. Historically, our operating cash flows have been sufficient to meet our short- and long-term capital expenditures related to our existing generating facilities, our debt service requirements, and our ordinary business operations. During the first nine months of 2007 our operating activities provided cash flow of $141.3 million. During the first nine months of 2006 cash needs exceeded our cash flows from operating activities by $3.7 million. Operating activities during the first nine months of 2007 were primarily impacted by the change in current liabilities, current assets, deferred energy, and regulatory assets and liabilities. Current liabilities changed $67.3 million primarily as a result of increased interest payable, increased accrued transportation costs related to our dispute with Norfolk Southern, increased accounts payable related to purchased power invoices and increased accounts payable—members related to the change in the margin stabilization adjustment slightly offset by a decrease in member prepayment balances. Current assets changed $25.5 million primarily due to the return to us of $23.6 million in collateral we were required to post as of December 31, 2006. Deferred energy changed $19.9 million as a result of the under-collection of energy costs. Regulatory assets and liabilities changed $17.5 million primarily due to the change in the fair value of our derivatives.

Financing Activities. In addition to liquidity from our operating activities, we maintain committed lines of credit and revolving credit facilities to cover short-term and medium-term funding needs. As of September 30, 2007, our total lines of credit were $155.0 million, and our total revolving credit facilities were $125.0 million. At September 30, 2007 and 2006, we had no short-term borrowings or letters of credit outstanding under any of these arrangements. We expect the working capital lines of credit and revolving credit facilities to be renewed as they expire.

Investing Activities. Investing activities in the first nine months of 2007 were primarily impacted by activity related to available for sale securities, interest earned on investments—other and cash and cash equivalents, as well as electric plant additions for our generating facilities.

Auction Rate Securities. As of September 30, 2007, we had $46.0 million invested in auction rate securities. These investments are included in investments—other on our Condensed Consolidated Balance Sheet and classified as available for sale. Auction rate securities pay a variable rate of interest which resets periodically in connection with the auction to purchase or sell the securities.

The volatility in the fixed income markets during the third quarter of 2007 resulted in a number of our auction rate securities having auctions that were not fully subscribed, which auction agents describe as failed auctions. At September 30, 2007 we had $33.9 million invested in auction rate securities with failed auctions. Similarly, as of November 8, 2007, we had $46.0 million invested in auction rate securities and we had $33.9 million invested in auction rate securities with failed auctions. These failed auctions resulted in the interest rates on these auction rate securities resetting at a predetermined spread to LIBOR, which, depending on the security, has ranged from 100 basis points to 150 basis points. All of the auction rate securities we owned at September 30 and November 8, 2007 were rated AA or AAA by Standard & Poors' Rating Services, Aa2 or Aaa by Moody's Investors Service, or AAA by Fitch, Inc.

Generally, the periodic auctions provide owners of auction rate securities the opportunity to liquidate their investment at par value. In the event of failed auctions these securities are typically illiquid. If the auction rate securities we own continue to experience failed auctions or their credit ratings deteriorate, we may adjust the carrying value of these investments. Based on our cash and cash equivalents balance and our expected operating cash flows, we currently do not anticipate the lack of liquidity for our auction rate securities will have a material impact on us.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

No material changes occurred in our exposure to market risk during the third quarter of 2007.

ITEM 4. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, our management, including the President and Chief Executive Officer, and Senior Vice President and Chief Financial Officer conducted an evaluation of the effectiveness of our disclosure controls and procedures. Based upon that evaluation, the President and Chief Executive Officer, and Senior Vice President and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that all material information required to be filed in this report has been made known to them in a timely manner. We have established a Disclosure Assessment Committee comprised of members from senior and middle management to assist in this evaluation. There have been no significant changes in our internal controls over financial reporting or in other factors that could significantly affect such controls during the past fiscal quarter.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Ragnar Benson

In December 2002, we entered into a contract with Ragnar Benson, Inc. ("RBI") for engineering, procurement and construction services relating to the construction of our Marsh Run combustion turbine facility. On December 23, 2004, we terminated the contract with RBI for default and filed suit in the U.S. District Court for the Eastern District of Virginia, Richmond Division, against RBI. On June 13, 2005, we executed an agreement with RBI's surety, Seaboard Surety Company ("Seaboard"), under which it assumed all responsibilities for the final completion of the Marsh Run facility in accordance with the terms of the original agreement with RBI. RBI and its parent companies, The Austin Company and Austin Holdings, Inc., filed for reorganization on October 14, 2005. Because RBI filed for reorganization during the legal proceeding, we served a lawsuit against Seaboard on February 10, 2006, in order to enforce the eventual outcome of the suit with RBI. On August 23, 2007, we settled our legal disputes with Seaboard. In full settlement of our legal disputes with Seaboard, we received a payment of $3.0 million from Seaboard and we were released of any and all remaining payment obligations. At the time of the settlement we had a $5.7 million liability recorded which was reversed based on the terms of the settlement. The $8.7 million impact of the settlement resulted in a reduction of the cost of our Marsh Run facility. The terms of our agreement provided for the assignment by ODEC to Seaboard of all of ODEC's rights and claims against RBI in the current reorganization proceedings including the judgment obtained against RBI, and Seaboard and ODEC each released the other from any and all claims, arising out of or related to the Marsh Run Project.

NOVEC

In the legal proceedings related to Northern Virginia Electric Cooperative ("NOVEC"), on July 6, 2007, FERC filed its brief with the United States Court of Appeals for the District of Columbia in response to NOVEC's May 7, 2007 brief. We filed an intervenor's brief on July 23, 2007, NOVEC filed its reply brief on August 21, 2007, and all parties filed final briefs on September 11, 2007. On October 29, 2007, the court issued an order scheduling oral argument for January 15, 2008. For further description of our legal proceedings related to NOVEC, see Part I, Item 3 of our 2006 Annual Report on Form 10-K.

Other Matters

No material developments have occurred in our legal proceedings with Norfolk Southern or FERC Proceedings Related to Potential Reorganization, since the filing of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2007. See "Legal Proceedings" in Part II, Item 1 of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2007. Other than legal proceedings arising out of the ordinary course of business, which management believes will not have a material adverse impact on our results of operations or financial condition, there is no other litigation pending or threatened against us.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in "Risk Factors" in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2006, which could affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

ITEM 5 – OTHER INFORMATION

NOVEC

We are currently in discussions with NOVEC about the possible termination of its wholesale power contract and its withdrawal as a member of ODEC. We will not consider any termination of the wholesale power contract or take any other action in connection with the resolution of our issues with NOVEC that we believe in any way could adversely affect our financial condition or that of our other member distribution cooperatives.

ITEM 6. EXHIBITS

31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. § 1350
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. § 1350

SIGNATURE

Pursuant to the requirements 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.

OLD DOMINION ELECTRIC COOPERATIVE
Registrant

Date: November 9, 2007

/s/Robert L. Kees
Robert L. Kees
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

EXHIBIT INDEX

Exhibit Number	Description of Exhibit
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. § 1350
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. § 1350

Exhibit 31.1

OLD DOMINION ELECTRIC COOPERATIVE

CERTIFICATION OF PRESIDENT AND CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Jackson E. Reasor, certify that:

1 I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;

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

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

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

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

b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5 The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the Audit Committee of registrant's Board of Directors (or persons performing the equivalent function):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2007

/s/Jackson E. Reasor
Jackson E. Reasor
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

OLD DOMINION ELECTRIC COOPERATIVE

CERTIFICATION OF PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert L. Kees, certify that:

1 I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;

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

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

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

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

b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5 The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the Audit Committee of registrant's Board of Directors (or persons performing the equivalent function):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2007

/s/Robert L. Kees
Robert L. Kees
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

Exhibit 32.1

OLD DOMINION ELECTRIC COOPERATIVE

**CERTIFICATION OF PRESIDENT AND CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Old Dominion Electric Cooperative (the "Company") on Form 10-Q for the period ending September 30, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jackson E. Reasor, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 9, 2007

/s/Jackson E. Reasor
Jackson E. Reasor
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 32.2

OLD DOMINION ELECTRIC COOPERATIVE

**CERTIFICATION OF PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER
PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Old Dominion Electric Cooperative (the "Company") on Form 10-Q for the period ending September 30, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert L. Kees, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 9, 2007

/s/Robert L. Kees
Robert L. Kees
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

Attachment E
Decommissioning Funding Assurance Report

Pursuant to 10 CFR 50.33(k) and 10 CFR 50.75(b), Virginia Electric and Power Company, doing business as Dominion Virginia Power (DVP or Dominion) and Old Dominion Electric Cooperative (ODEC) hereby submit this decommissioning funding report in support of their application for a combined Construction Permit and Operating License for North Anna Unit 3. Dominion and ODEC certify that decommissioning funding assurance will be provided in an amount and by the method described below.

Amount of Decommissioning Funds

Dominion has calculated the decommissioning funding assurance amount escalated to January 1, 2007 pursuant to the methodology set out in 10 CFR 50.75(c), using available regional labor and energy escalation factors from the Bureau of Labor Statistics, and escalation factors for waste burial from NUREG-1307, Revision 12, which is the most currently available revision at this time. The 1986 BWR base decommissioning amount is premised on the best available estimate of the thermal rating of the new reactor of 4500 MWt. Dominion has calculated the decommissioning funding assurance amount assuming disposal of LLRW using waste vendors. This calculation results in a decommissioning funding assurance amount of $518,033,205.

The calculation of the decommissioning funding assurance amount assuming the use of waste vendors is set forth in Appendix A.

Dominion will provide assurance for 88.4 percent of this amount and ODEC will provide assurance for 11.6 percent of this amount, in proportion to their respective ownership shares.

Decommissioning Funding Assurance Mechanism

Pursuant to 10 CFR 50.75(b), a reactor licensee is required to provide decommissioning funding assurance by one or more of the methods described in 10 CFR 50.75(e), as determined to be acceptable to the NRC. Dominion and ODEC have each chosen to provide decommissioning funding assurance for their respective shares of the decommissioning funding amount by means of external sinking funds established and maintained by setting funds aside periodically in an account segregated from licensee assets and outside the administrative control of the licensee and its subsidiaries or affiliates in which the total amount of funds would be sufficient to pay decommissioning costs at the time permanent termination of operations is expected. This method is permitted pursuant to 10 CFR 50.75(e)(1)(ii). Both Dominion's and ODEC's external sinking fund will be in the form of a trust; will be established in writing and maintained at all times in the United States with an entity that is an appropriate State or Federal government agency, or an entity whose operations are regulated and examined by a State or Federal agency; and will include the provisions required by 10 CFR 50.75(h)(2).

For purposes of establishing the amount of periodic funding required to meet the necessary decommissioning amount at the expected time of permanent termination of operations, Dominion and ODEC will take credit for projected earnings on the external sinking funds using up to a 2 percent real annual rate of return from the time of future funds' collection up to permanent termination of operations. The funding amount will meet or exceed the amount required for decommissioning specified in 10 CFR 50.75(c).

Use of an external sinking fund is appropriate because both Dominion and ODEC will be entities that recover, either directly or indirectly, their share of the estimated total cost of decommissioning through rates established by "cost of service" or similar ratemaking regulation.

Certification Updates, Financial Instruments, and Annual Adjustment

Two years and one year before the scheduled date for initial loading of fuel, Dominion and ODEC will submit a report updating this certification in accordance with 10 CFR 50.75(e)(3) and providing copies of the financial instruments to be used. In addition, no later than 30 days after the NRC publishes the notice in the Federal Register under 10 CFR 52.103(a), Dominion and ODEC will submit a report containing a certification that the financial assurance for decommissioning is being provided in an amount specified in the most recent updated certification and will include a copy of the executed financial agreements obtained to satisfy the requirements of 10 CFR 50.75(e). Thereafter, the decommissioning funding amount will be adjusted annually using a rate at least equal to that stated in 10 CFR 50.75(c)(2).

Appendix A

NAPS U3 - NRC Minimum Calculation Worksheet (in whole dollars)				
Based on				**NUREG-1307, REV 12**
Thermal Power Rating - MWt				**4,500**
BWR Formula				135 Million Base
Base Cost (January 1986 Dollars)				$135,000,000
Adjustment Factor (12/31/2006 Dollars)				3.8372830036
Adjusted Level (12/31/2006 Dollars)				$518,033,205
NRC Minimum as of 12/31/2006				**$518,033,205**
	Factor L [1]	**Factor E [2]**	**Factor B [3]**	**Adjustment Factor**
Weighting	0.66	0.12	0.22	
2006	2.0493	1.9952	10.206	
Components	1.3525	0.2394	2.2453	3.8372830
South Region-Labor	**Dec 2005 Ref**	**12/31/2006**	**Scaling Factor**	
CIU2010000000220I	1.98	**103.5**	2.049	
Electric / Light Fuel	**1986 Ref**	**09/30/2006**	**2005/1986**	**Allocation %**
Industrial Electric (Px)	114.2	**181.0**	1.585	54%
Light Fuel Oil (Fx)	82.0	**203.1**	2.477	46%
Burial Adjustment Factor (BWR)		**10.206**	**NUREG SR1307 Rev12**	
(1) Factor L: Labor escalation factor to current year, the source is Bureau of Labor Statistics Data, Employment Cost Index, Series ecu13202i (South Region) through 12/2005. Starting 01/2006 - Table 6 - South Region - South Atlantic				
(2) Factor E: Energy escalation factor to current year, the source is a weighted calculation using Bureau of Labor Statistics Data, Producer Price Index-Commodities, series wpu0543 (industrial electric power) and wpu 0573 (light fuel oils)				
(3) Factor B: LLRW escalation factor for Non-Atlantic Compact, South Carolina, per NUREG-1307, Rev 12, Table 2.1 assuming the application of waste vendor sevices to reduce burial volumes				