UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 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 001-08489

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)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, no 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 x No ¨

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

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

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

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 x 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 x

The aggregate market value of the common stock held by non-affiliates of the registrant was approximately $24.3 billion based on the closing price of Dominion s common stock as reported on the New York Stock Exchange as of the last day of the registrant s most recently completed second fiscal quarter.

As of February 1, 2007, Dominion had 348,971,327 shares of common stock outstanding.

DOCUMENT INCORPORATED BY REFERENCE.

(a) Portions of the 2007 Proxy Statement are incorporated by reference in Part III.

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DOMINION RESOURCES, INC.

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PART 1

ITEM 1. BUSINESS

THE COMPANY

Dominion Resources, Inc. (Dominion) is a fully integrated gas and electric holding company headquartered in Richmond, Virginia. Dominion was incorporated in Virginia in 1983.

Dominion concentrates its efforts largely in the energy intensive Northeast, Mid-Atlantic and Midwest regions of the United States (U.S.).

The terms Dominion, Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any 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.

Our principal direct legal subsidiaries are Virginia Electric and Power Company (Virginia Power), Consolidated Natural Gas Company (CNG), Dominion Energy, Inc. (DEI) 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. CNG operates in all phases of the natural gas business, explores for and produces natural gas and oil and provides a variety of energy marketing services. In addition, CNG is a transporter, distributor and retail marketer of natural gas, serving customers in Pennsylvania, Ohio, West Virginia and other states. CNG also operates a liquefied natural gas (LNG) import and storage facility in Maryland. DEI is involved in merchant generation, energy marketing and price risk management activities and natural gas and oil exploration and production. VPEM provides fuel and price risk management services to Virginia Power and other Dominion affiliates and engages in energy trading activities.

As of December 31, 2006, we had approximately 17,500 full-time employees. Approximately 6,300 employees are subject to collective bargaining agreements.

Our principal executive offices are located at 120 Tredegar Street, Richmond, Virginia 23219 and our telephone number is (804) 819-2000.

WHERE YOU CAN FIND MORE INFORMATION ABOUT DOMINION

We file our annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission (SEC). Our SEC filings are available to the public over the Internet at the SEC s website at http://www.sec.gov (File No. 001-08489). You may also read and copy any document we file at the SEC s public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

Our website address is www.dom.com. We make available, free of charge through our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports as soon as practicable after filing or furnishing the material with the SEC. You may also request a copy of these filings, at no cost, by writing or telephoning us at: Corporate Secretary, Dominion, 120 Tredegar Street, Richmond, Virginia 23219, Telephone (804) 819-2000. Information contained on our website is not incorporated by reference in this report.

SIGNIFICANT DEVELOPMENTS

Following are significant acquisitions and divestitures during the last five years.

Acquisitions

PABLO ENERGY, LLC

In February 2006, we completed the acquisition of Pablo Energy, LLC (Pablo) for approximately $92 million in cash. Pablo holds producing and other properties located in the Texas Panhandle area. The operations of Pablo are included in our Dominion Exploration and Production (E&P) operating segment.

KEWAUNEE POWER STATION

In July 2005, we completed the acquisition of the 556-megawatt (Mw) Kewaunee nuclear power station (Kewaunee), located in northeastern Wisconsin, from Wisconsin Public Services Corporation for approximately $192 million in cash. The operations of Kewaunee are included in our Dominion Generation operating segment.

USGEN POWER PLANTS

In January 2005, we completed the acquisition of three fossil-fired generation facilities from USGen New England, Inc. for $642 million in cash. The plants include the 1,560 Mw Brayton Point Power Station in Somerset, Massachusetts; the 754 Mw Salem Harbor Station in Salem Massachusetts; and the 432 Mw Manchester Street Station in Providence, Rhode Island. The operations of these facilities are included in our Dominion Generation operating segment.

COVE POINT LNG LIMITED PARTNERSHIP

In September 2002, we acquired 100% ownership of Cove Point LNG Limited Partnership (Cove Point), a cost based rate-regulated entity from a subsidiary of The Williams Companies for $225 million in cash. Cove Point s assets include an LNG natural gas import and storage facility located near Baltimore, Maryland and an approximately 85-mile natural gas pipeline. Cove Point is included in our Dominion Energy operating segment.

MIRANT STATE LINE VENTURES, INC.

In June 2002, we acquired 100% ownership of Mirant State Line Ventures (State Line) from a subsidiary of Mirant Corporation for $185 million in cash. State Line s assets include a 515 Mw generation facility located near Hammond, Indiana. Its operations are included in our Dominion Generation operating segment.

Dispositions

SALE OF E&P PROPERTIES

In 2006, we received approximately $393 million of proceeds from sales of certain gas and oil properties, primarily resulting from the fourth quarter sale of certain properties located in Texas and New Mexico. In December 2004, we sold the majority of our natural gas and oil assets in British Columbia, Canada for $476 million. These assets were included in our Dominion E&P operating segment.

PENDING SALES

In addition to the completed acquisitions and divestitures above, we have entered into an agreement with Equitable Resources, Inc. to sell two of our wholly-owned regulated gas distribution subsidiaries for approximately $970 million plus adjustments to reflect capital expenditures and changes in working capital. We have also entered into an agreement with an entity jointly owned by Tenaska Power Fund, L.P. and Warburg Pincus LLC to sell three of our natural gas-fired merchant generation peaking facilities for approximately $256 million. A more detailed description of these activities can be found in our discussion of our Dominion Delivery and Dominion Generation operating segments.

POTENTIAL SALE OF SUBSTANTIAL PORTION OF E&P ASSETS

In November 2006, we announced our decision to pursue the sale of all of our oil and natural gas E&P operations and assets, with the exception of those located in the Appalachian Basin. As of December 31, 2006, our natural gas and oil assets excluding the Appalachian Basin included about 5.5 trillion cubic feet of proved reserves. The Appalachian assets that we would retain constituted approximately 15% of our total reserves as of December 31, 2006. These operations and assets are principally part of our Dominion E&P operating segment. See *Introduction* in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A).

OPERATING SEGMENTS

We manage our operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion E&P. We also report a Corporate segment that includes our corporate, service company and other functions. While we manage our daily operations through our operating segments, our assets remain wholly-owned by our legal subsidiaries. For additional financial information on business segments and geographic areas, including revenues from external customers, see Note 28 to our Consolidated Financial Statements. For additional information on operating revenue related to our principal products and services, see Note 6 to our Consolidated Financial Statements.

Dominion Delivery

Dominion Delivery includes our regulated electric and gas distribution and customer service businesses, as well as nonregulated retail energy marketing operations. Electric distribution operations serve residential, commercial, industrial and governmental customers in Virginia and northeastern North Carolina. Gas distribution operations serve residential, commercial and industrial gas sales and transportation customers in Ohio, Pennsylvania and West Virginia. Nonregulated retail energy marketing operations include the marketing of gas, electricity and related products and services to residential, industrial and small commercial customers in the Northeast, Mid-Atlantic and Midwest.

In March 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 expected to close by the end of the second quarter of 2007, subject to state regulatory approvals in Pennsylvania and West Virginia, as well as approval under the Hart-Scott-Rodino Act.

COMPETITION

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

Retail competition for gas supply exists to varying degrees in the three states in which our gas distribution subsidiaries operate. In Pennsylvania, supplier choice is available for all residential and small commercial customers. In Ohio, there has been no legislation enacted to require supplier choice for residential and commercial natural gas consumers. However, we have offered an Energy Choice program to customers, in cooperation with the Public Utilities Commission of Ohio (Ohio Commission). West Virginia does not require customer choice in its retail natural gas markets at this time. See *Regulation State Regulations Gas* for additional information.

REGULATION

Dominion 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 Electric* for additional information.

Dominion Delivery s gas distribution service, including the rates that it may charge customers, is regulated by the Ohio Commission, the Pennsylvania Public Utility Commission (Pennsylvania Commission) and the West Virginia Public Service Commission (West Virginia

Commission). See *Regulation State Regulations Gas* for additional information.

PROPERTIES

Dominion Delivery 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 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.

Dominion Delivery s gas distribution network is located in the states of Ohio, Pennsylvania and West Virginia. This network involves approximately 27,700 miles of pipe, exclusive of service lines of two inches in diameter or less. The rights-of-way grants for many natural gas pipelines have been obtained from the actual owner of real estate, as underlying titles have been examined. Where rights-of-way have not been obtained they could be acquired from private owners by condemnation, if necessary. Many natural gas pipelines are on publicly owned property, where company rights and actions are determined on a case-by-case basis, with results that range from reimbursed relocation to revocation of permission to operate. Delivery also operates 10 underground gas storage fields located in Ohio and Pennsylvania, with more than 800 storage wells and approximately 121,000 acres of operated leaseholds.

The total designed capacity of the underground storage fields operated by Dominion Delivery is approximately 203 billion cubic feet (bcf). The Dominion Delivery segment has about 40 compressor stations with approximately 65,000 horsepower of installed compression.

SOURCES OF ENERGY SUPPLY

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

Dominion Delivery is engaged in the sale and storage of natural gas through its operating subsidiaries. Dominion Delivery s natural gas supply is obtained from various sources including

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purchases from: major and independent producers in the Mid-Continent and Gulf Coast regions, local producers in the Appalachian area, and gas marketers.

SEASONALITY

Dominion 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, and gas, to meet heating needs.

Dominion Energy

Dominion Energy includes our regulated electric transmission, natural gas transmission pipeline and storage businesses and the Cove Point LNG facility. It also includes gathering and extraction activities, plus certain Appalachian natural gas production. Dominion Energy also includes producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage, associated gas trading and the results of certain energy trading activities exited in December 2004. The electric transmission business serves 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. The gas transmission pipeline and storage business serves our gas distribution businesses and other customers in the Northeast, Mid-Atlantic and Midwest.

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.

Dominion Energy s gas transmission operations compete with domestic and Canadian pipeline companies. We also compete with gas marketers seeking to provide or arrange transportation, storage and other services. Alternative energy sources, such as oil or coal, provide another level of competition. Although competition is based primarily on price, the array of services that can be provided to customers is also an important factor. The combination of capacity rights held on certain long-line pipelines, a large storage capability and the availability of numerous receipt and delivery points along our own pipeline system enables us to tailor our services to meet the needs of individual customers.

REGULATION

Dominion Energy s electric transmission rates, tariffs and terms of service are subject to regulation by the Federal Energy Regulatory Commission (FERC). FERC also regulates our natural gas pipeline transmission, storage and LNG operations. Electric trans

mission siting authority remains the exclusive jurisdiction of the Virginia and North Carolina Commissions. However, the Energy Policy Act of 2005 provides FERC with certain limited backstop authority for transmission siting, the implications of which remain unclear. See *State Regulations* and *Federal Regulations* in *Regulation* for additional information.

PROPERTIES

Dominion Energy 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 Dominion Energy s electric transmission lines cross national parks and forests under permits entitling the federal government to use, at specified charges, any surplus capacity that may exist in these lines.

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

Each year, as part of PJM s 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.

Dominion Energy has approximately 7,800 miles of gas transmission, gathering and storage pipelines located in the states of Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. Dominion Energy operates 17 underground gas storage fields located in New York, Ohio, Pennsylvania and West Virginia, with more than approximately 1,500 storage wells and approximately 252,000 acres of operated leaseholds.

The total designed capacity of the underground storage fields operated by Dominion Energy is approximately 776 bcf. Six storage fields are jointly-owned and operated by Dominion Energy. The capacity of those six fields owned by our partners totals about 242 bcf. Dominion Energy also has about 8 bcf of above-ground storage capacity at its Cove Point LNG facility. Dominion Energy has about 90 compressor stations with approximately 630,000 installed compressor horsepower.

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The following map illustrates Dominion Energy s gas transmission pipelines, storage facilities, LNG facility and electric transmission lines.

SOURCES OF ENERGY SUPPLY

Our large underground natural gas storage network and the location of our pipeline system are a significant link between the country s major interstate gas pipelines and large markets in the Northeast and Mid-Atlantic regions. Our pipelines are part of an interconnected gas transmission system, which provides access to supplies nationwide for local distribution companies, marketers, power generators and industrial and commercial customers.

Our underground storage facilities play an important part in balancing gas supply with consumer demand and are essential to serving the Northeast, Mid-Atlantic and Midwest regions. In addition, storage capacity is an important element in the effective management of both gas supply and pipeline transport capacity.

SEASONALITY

Dominion Energy s nonregulated businesses are affected by seasonal changes in the prices of commodities that they transport, store and actively market and trade.

Dominion Generation

Dominion Generation s electric utility and merchant fleet includes approximately 28,000 Mw of generation capability. The generation mix is diversified and includes coal, nuclear, gas, oil, hydro and purchased power. Our electric generation operations serve customers in the Northeast, Mid-Atlantic and Midwest.

Our generation facilities are located in Virginia, West Virginia, North Carolina, Connecticut, Illinois, Indiana, Pennsylvania, Ohio, Massachusetts, Rhode Island and Wisconsin. Dominion Generation also includes energy marketing and price risk management activities for our generation assets.

In December 2006, we reached an agreement with an entity jointly owned by Tenaska Power Fund, L.P. and Warburg Pincus LLC to sell three of our natural gas-fired merchant generation peaking facilities (Peaker facilities). Peaking facilities are used during times of high electricity demand, generally in the summer months. 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 sale is expected to result in proceeds of approximately $256 million and is expected to close by the end of the first quarter of 2007, pending regulatory approval by FERC. We have obtained approval from the Federal Trade Commission. No state regulatory approvals are required.

We offered the facilities for sale following a review of our portfolio of assets. We have decided not to sell a fourth merchant generation facility, State Line, a 515 Mw coal-fired facility in Hammond, Indiana.

COMPETITION

Retail choice has been available for Dominion Generation s Virginia jurisdictional electric utility 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.

Dominion Generation s merchant generation fleet owns and operates several large facilities in the Midwest. The output from these generating plants is sold under long-term contracts and is therefore largely unaffected by competition.

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Dominion Generation s remaining merchant assets operate within functioning RTOs. Competitors include other generating assets bidding to operate within the RTOs. These RTOs have clearly identified market rules that ensure the competitive wholesale market is functioning properly. Dominion Generation s merchant units have a variety of short and medium-term contracts, and also compete in the spot market with other generators to sell a variety of products including energy, capacity and operating reserves. It is difficult to compare various types of generation given the wide range of fuels, fuel procurement strategies, efficiencies and operating characteristics of the fleet within any given RTO. However, we apply our expertise in operations, dispatch and risk management to maximize the degree to which our merchant fleet is competitive compared to similar assets within the region.

REGULATION

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

PROPERTIES

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

In December 2006, we acquired a 50% interest in a joint venture with Shell WindEnergy Inc. (Shell) to develop a wind-turbine facility in Grant County, West Virginia, which will produce approximately 164 Mw of electricity and is expected to begin operations in the fourth quarter of 2007.

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 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

Dominion Generation uses a variety of fuels to power our electric generation, as described below.

Nuclear Fuel Dominion 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 Dominion Generation primarily utilizes coal, oil and natural gas in its fossil fuel plants. Dominion Generation s

coal supply is obtained through long-term contracts and short-term spot agreements.

Dominion 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.

Dominion 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

Dominion Generation s sales of electricity typically vary seasonally based on demand for electricity by residential and commercial customers for cooling and heating use based on changes in temperature. Sales of electricity from our merchant generation plants are also affected by seasonal changes in demand and commodity prices.

NUCLEAR DECOMMISSIONING

Dominion Generation has a total of seven licensed, operating nuclear reactors at its Surry and North Anna plants in Virginia, its Millstone plant in Connecticut and its Kewaunee plant in Wisconsin.

Surry and North Anna serve customers of our regulated electric utility operations. Millstone and Kewaunee are nonregulated merchant plants. Millstone has two operating units. A third Millstone unit ceased operations before we acquired the plant.

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. As part of our acquisition of both Millstone and Kewaunee, we acquired decommissioning funds for the related units. We believe that the amounts currently available in our decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units, without any additional contributions to those trusts.

The total estimated cost to decommission our eight nuclear units is $4.1 billion in 2006 dollars and is primarily based upon site-specific studies completed in 2006. For all units except Millstone Unit 1 and Unit 2, the current cost estimates assume decommissioning activities will begin shortly after cessation of operations, which will occur when the operating licenses expire. Millstone Unit 1 is not in service and selected minor decommissioning activities are being performed. This unit will continue to be monitored until full decommissioning activities begin for the remaining Millstone units. We expect to start minor decommissioning activities at Millstone Unit 2 in 2035, with full decommissioning of Millstone Units 1, 2 and 3 during the period 2045 to 2059. We expect to decommission the Surry and North Anna units during the period 2032 to 2059. We intend to apply for a 20-year life extension in 2008 for our Kewaunee unit. If the NRC approves the life extension application, we expect to decommission Kewaunee during the period 2033 to 2059. The license expiration dates for our units are shown in the following table.

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(millions)	Surry Unit 1	Surry Unit 2	North Anna Unit 1	North Anna Unit 2	Millstone Unit 1	Millstone Unit 2	Millstone Unit 3	Kewaunee Unit 1	Total
NRC license expiration year	2032	2033	2038	2040	(1)	2035	2045	2013	
Most recent cost estimate (2006 dollars)	$ 457	$ 484	$ 436	$ 458	$ 630	$ 523	$ 531	$ 585	$ 4,104
Funds in trusts at December 31, 2006	361	356	296	280	309	362	355	472	2,791
2006 contributions to trusts	1.4	1.5	1.0	0.9					4.8

(1) Unit 1 ceased operations in 1998 before our acquisition of Millstone.

Dominion E&P

Dominion E&P includes our gas and oil exploration, development and production operations. These operations are 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, as well as the Western Canadian Sedimentary Basin.

In November 2006, we announced our decision to pursue the sale of all of our oil and natural gas E&P operations and assets, with the exception of those located in the Appalachian Basin. Any disposition would allow us to focus on our electric generating and energy distribution, transmission and storage businesses and realign our operations and risk profile more closely with our peer investment group of utilities. As of December 31, 2006, our natural gas and oil assets excluding the Appalachian Basin included about 5.5 trillion cubic feet of proved reserves. The Appalachian assets that we would retain constitute approximately 15% of our total proved reserves.

Proceeds from any sale are expected to be used to reduce debt repurchase shares of our common stock, and/or acquire assets related to our remaining core businesses. We expect to initiate a formal sales process in early 2007. Closing of any sale or sales is targeted for mid-2007.

In February 2006, we completed the acquisition of Pablo for approximately $92 million in cash. Pablo holds producing and other properties located in the Texas Panhandle area. In 2006, we received approximately $393 million of proceeds from the sale of gas and oil properties, primarily resulting from the fourth quarter sale of certain properties located in Texas and New Mexico.

COMPETITION

Dominion E&P s competitors range from major, international oil companies to smaller, independent producers. Dominion E&P faces significant competition in bidding for federal offshore leases and in obtaining leases and drilling rights for onshore properties. As the operator of production properties, Dominion E&P also faces competition in securing drilling equipment and supplies for exploration and development.

Dominion E&P sells most of its deliverable natural gas and oil into short and intermediate-term markets. Dominion E&P faces challenges related to the marketing of its natural gas and oil pro-

duction due to the contraction of participants in the energy marketing industry. However, Dominion E&P owns a large and diverse natural gas and oil portfolio and maintains an active gas and oil marketing presence in its primary production regions, which strengthens its knowledge of the marketplace and delivery options.

REGULATION

Our E&P operations are subject to regulation by numerous federal and state authorities. The pipeline transportation of our natural gas production is regulated by FERC; pipelines operating on or across the Outer Continental Shelf are subject to the Outer Continental Shelf Lands Act, which requires services to be offered on an open-access, non-discriminatory basis. Our production operations in the Gulf of Mexico and most of our operations in the western U.S. are located on property subject to federal oil and gas leases that are administered by the Minerals Management Service (MMS) or the Bureau of Land Management. These leases are issued through a competitive bidding process and require us to comply with stringent regulations. Offshore production facilities must comply with MMS regulations relating to engineering, construction, operations and the plugging and abandonment of wells. Our production operations are also subject to environmental regulations including regulations relating to oil spills into navigable waters of the U.S. See *Regulation Federal Regulations* and *Regulation Environmental Regulation*s for additional information.

PROPERTIES

Dominion E&P owns 6.5 trillion cubic feet proved equivalent of natural gas and oil reserves and produces approximately 1.3 billion cubic feet equivalent of natural gas per day from its leasehold acreage and facility investments. Either alone or with partners, we hold interests in natural gas and oil lease acreage, wellbores, well facilities, production platforms and gathering systems. We also own or hold rights to seismic data and other tools used in exploration and development drilling activities. Our share of developed leasehold totals 3.2 million acres, with another 2.0 million acres held for future exploration and development drilling opportunities. See also Item 2. Properties for additional information on Dominion E&P s properties.

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Note: Includes the Dominion E&P segment and the production activity of Dominion Transmission, Inc., which is included in the Dominion Energy segment.

Bcfe = billion cubic feet equivalent

Mmcfe = million cubic feet equivalent

SEASONALITY

Dominion E&P s business can be affected by seasonal changes in the demand for natural gas and oil. Commodity prices, including prices for our unhedged natural gas and oil production, can be affected by seasonal weather changes and by the effects of weather on operations.

Corporate

We also have a Corporate segment that includes:

- Our corporate, service company and other functions, including unallocated debt;
- Corporate-wide commodity risk management;
- The remaining assets of Dominion Capital, Inc., (DCI) a financial services subsidiary, which are being divested;
- The net impact of our discontinued telecommunications operations that were sold in May 2004;
- The net impact of the discontinued operations of the Peaker facilities; 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.

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

ELECTRIC

Our electric retail service is subject to regulation by the Virginia Commission and the North Carolina Commission.

Our electric utility subsidiary holds certificates of public convenience and necessity which authorize it to maintain and operate its electric facilities now in operation and to sell electricity to customers. However, this subsidiary 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 North Carolina Commission regulate our electric utility subsidiary s transactions with affiliates, transfers of certain facilities and issuance of securities.

Rates

Historically, the rates of our electric utility subsidiary have been based on the cost of providing traditional bundled electric service (i.e., the combination of generation, transmission and distribution 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

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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 the base rates of our electric utility 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. In Virginia, 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 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 our acquisition of 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 the operations of our electric utility subsidiary. 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, among other things: capped base rates, RTO participation, retail choice, stranded cost 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 Commission 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 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.

GAS

Our gas distribution services are regulated by the Ohio Commission, the Pennsylvania Commission and the West Virginia Commission.

Status of Competitive Retail Gas Services

Each of the three states in which we have gas distribution operations has enacted or considered legislation regarding a competitive deregulation of natural gas sales at the retail level.

Ohio Ohio has not enacted legislation requiring supplier choice for residential and commercial natural gas consumers. However, in cooperation with the Ohio Commission, we have offered retail choice to residential and commercial customers. At December 31, 2006, approximately 814,000 of our 1.2 million Ohio customers were participating in this Energy Choice program. Large industrial customers in Ohio also source their own natural gas supplies. In May 2006, the Ohio Commission approved a two-year pilot program to improve and expand our Energy Choice Program. Under the previous structure, non-Energy Choice customers purchased gas directly from us at a monthly gas cost recovery rate that included true-up adjustments that could change significantly from one quarter to the next. In August 2006, the Ohio Commission approved an auction that enabled us to enter into gas purchase contracts with selected suppliers at a fixed price above the New York Mercantile Exchange month-end settlement. This pricing mechanism, implemented in October 2006, replaces the traditional gas cost recovery rate with a monthly market price that eliminates the true-up adjustment, making it easier for customers to compare and switch to competitive suppliers by the end of the transition period. Subject to Ohio Commission approval, we plan to exit the gas merchant function in Ohio entirely and have all customers select an alternate gas supplier. We will continue to be the provider of last resort in the event of default by a supplier.

Pennsylvania In Pennsylvania, supplier choice is available for all residential and small commercial customers. At December 31, 2006, approximately 99,000 residential and small commercial customers had opted for Energy Choice in our Pennsylvania service area. Nearly all Pennsylvania industrial and large commercial customers buy natural gas from nonregulated suppliers.

West Virginia At this time, West Virginia has not enacted legislation to require customer choice in its retail natural gas markets. However, the West Virginia Commission has issued regulations to govern pooling services, one of the tools that natural gas suppliers may utilize to provide retail customer choice in the future and has issued rules requiring competitive gas service providers to be licensed in West Virginia.

Rates

Our gas distribution subsidiaries are subject to regulation of rates and other aspects of their businesses by the states in which they operate Pennsylvania, Ohio and West Virginia. When necessary, our gas distribution subsidiaries seek general base rate increases on a timely basis to recover increased operating costs. In addition to general rate increases, our gas distribution subsidiaries make routine separate filings with their respective state regulatory commissions to reflect changes in the costs of purchased gas. These purchased gas costs are subject to rate recovery through a mechanism that ensures dollar for dollar recovery of prudently incurred costs. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The purchased gas cost recovery filings generally cover prospective one, three or twelve-month periods. Approved increases or decreases in gas cost recovery rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

Federal Regulations

PUBLIC UTILITY HOLDING COMPANY ACT OF 2005 (PUHCA 2005)

The Energy Policy Act of 2005 (EPACT) provided for the repeal of the Public Utility Holding Company Act of 1935 (1935 Act) in February 2006. The 1935 Act and related regulations issued by the SEC governed our activities with respect to the issuance and acquisition of securities, acquisition and sale of utility assets, certain transactions among affiliates, engaging in businesses activities not directly related to the utility or energy business and other matters. Since the effective date of repeal of the 1935 Act, we are considered a holding company under PUHCA 2005, the rules and regulations of which are administered by FERC. PUHCA 2005 is more limited in scope than the 1935 Act and relates primarily to certain record-keeping requirements and transactions involving public utilities and their affiliates.

FEDERAL ENERGY REGULATORY COMMISSION

Electric

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. Our electric utility subsidiary and merchant generators sell electricity in the wholesale market under our market-based sales tariffs authorized by FERC. In addition, our electric utility subsidiary has 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 significant expenditures beyond the normal course of business.

Gas

FERC regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, as amended. Under the Natural Gas Act, FERC has authority over rates, terms and conditions of services performed by our interstate natural gas company subsidiaries, including Dominion Transmission, Inc. (DTI), Dominion Cove Point LNG, LP (DCP) and the Dominion South Pipeline Company, LP. FERC also has jurisdiction over

siting, construction and operation of natural gas import facilities and interstate natural gas pipeline facilities.

Our interstate gas transportation and storage activities are conducted on an open access basis, in accordance with certificates, tariffs and service agreements on file with FERC.

We are also subject to the Pipeline Safety Act of 2002 (2002 Act), which mandates inspections of interstate and intrastate natural gas transmission and storage pipelines, particularly those located in areas of high-density population. We have evaluated our natural gas transmission and storage properties, as required by the Department of Transportation regulations under the 2002 Act, and have implemented a program of identification, testing and potential remediation activities. These activities are ongoing.

In May 2005, FERC approved a comprehensive rate settlement with our subsidiary, DTI, and its customers and interested state commissions. The settlement, which became effective July 1, 2005, revised our natural gas transportation rates and reduced fuel retention levels for storage service customers. As part of the settlement, DTI and all signatory parties agreed to a rate moratorium until 2010.

In June 2006, we filed a general rate proceeding for DCP. The rates to be established in this case will take effect as of January 1, 2007. This rate proceeding will enable DCP to update the cost of service underlying its rates, including recovery of costs associated with the 2002 to 2003 reactivation of the LNG import terminal. Resolution of the case is expected during the first half of 2007.

We implemented various other rate filings, tariff changes and negotiated rate service agreements for our FERC-regulated businesses during 2006. In all material respects, these filings were approved by FERC in the form requested by us and were subject to only minor modifications.

FEDERAL OFFSHORE OIL AND GAS LEASE LEGISLATION

A bill passed by the U.S. House of Representatives on January 16, 2007, but not yet enacted into law, addresses certain federal offshore and gas leases issued in 1998 and 1999 that do not include a provision requiring royalties to be paid on specified royalty suspension volumes when oil and gas commodity futures closing prices exceed specified threshold levels (as is the case under current market conditions). The bill imposes certain conservation of resources fees and imposes sanctions on lessees, including disqualification from future offshore lease sales, for those who fail to comply. The Senate is considering such legislation. For further discussion, see *Offshore Oil and Gas Leases* in *Future Issues* of MD&A.

Environmental Regulations

Each of our operating segments faces substantial regulation and compliance costs with respect to environmental matters. For a discussion of significant aspects of these matters, including current and planned capital expenditures relating to environmental compliance, see *Environmental Matters* in *Future Issues and Other Matters* in MD&A. Additional information can also be found in Item 3. Legal Proceedings and Note 23 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

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implemented, will require significant reductions in sulfur dioxide (SO_2), nitrogen oxide (NO_X) 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. Separate from CAIR and CAMR, Massachusetts has regulations specifically targeting reductions in NO_x, SO_2, carbon dioxide (CO_2) and mercury emissions from our affected facilities in Massachusetts.

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% over the period 2002 through 2012. Several legislative proposals in the U.S. Congress have in the past and are likely in the future to include provisions seeking to target the reductions of greenhouse gas emissions. In addition to possible federal action, some states in which we operate have already or may adopt carbon reduction programs. For example, Massachusetts has implemented regulations requiring reductions in CO_2 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. Refer to Note 23 to our Consolidated Financial Statements for a description of our exposure relating to 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 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 Dominion 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 our decommissioning trusts, see *Dominion Generation Nuclear Decommissioning* and Note 23 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 natural gas and affect the price of energy commodities. In addition, severe weather, including hurricanes, winter storms and droughts, can be destructive, causing outages, production delays 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 for our regulated electric utility. 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.

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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.

Our merchant power business is operating in a challenging market, which could adversely affect our results of operations and future growth. The success of our merchant power business depends upon favorable market conditions as well as our ability to find buyers willing to enter into power purchase agreements at prices sufficient to cover operating costs. We attempt to manage these risks by entering into both short-term and long-term fixed price sales and purchase contracts and locating our assets in active wholesale energy markets. However, high fuel and commodity costs and excess capacity in the industry could adversely impact our results of operations.

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. In addition, we purchase and sell commodity-based contracts in the natural gas, electricity and oil markets for trading purposes. 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.

In addition, we use derivatives to hedge future sales of our merchant generation and gas and oil production, which may limit the benefit we would otherwise receive from increases in commodity prices. These hedge arrangements generally include collateral requirements that require us to deposit funds or post letters of credit with counterparties to cover the fair value of covered contracts in excess of agreed upon credit limits. When commodity prices rise to levels substantially higher than the levels where we have hedged future sales, we may be required to use a material portion of our available liquidity and obtain additional liquidity to cover these collateral requirements. In some circumstances, this could have a compounding effect on our financial liquidity and results of operations.

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 trading contracts, see *Market Risk Sensitive Instruments and Risk Management* in Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Notes 2 and 8 to our Consolidated Financial Statements.

Our E&P business is affected by factors that cannot be predicted or controlled and that could damage facilities, disrupt production or reduce the book value of our assets. Factors that may affect our financial results include, but are not limited to: damage to or suspension of operations caused by weather, fire, explosion or other events at our or third-party gas and oil facilities, fluctuations in natural gas and crude oil prices, results of future drilling and well completion activities, our ability to acquire additional land positions in competitive lease areas, operational risks that could disrupt production and geological and other uncertainties inherent in the estimate of gas and oil reserves.

Short-term market declines in the prices of natural gas and oil could adversely affect our financial results by causing a permanent write-down of our natural gas and oil properties as required by the full cost method of accounting. Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized. If net capitalized costs exceed the present value of estimated future net revenues based on hedge-adjusted period-end prices from the production of proved gas and oil reserves (the ceiling test) at the end of any quarterly period, then a permanent write-down of the assets must be recognized in that period.

In the past, we have maintained business interruption, property damage and other insurance for our E&P operations. However, the increased level of hurricane activity in the Gulf of Mexico led our insurers to terminate certain coverages for our E&P operations; specifically, our Operator s Extra Expense (OEE), offshore property damage and offshore business interruption coverage was terminated. All onshore property coverage (with the exception of OEE) and liability coverage commensurate

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with past coverage remained in place for our E&P operations. Our OEE coverage for both onshore and offshore E&P operations was reinstated under a new policy. However, efforts to replace the terminated insurance for our E&P operations for offshore property damage and offshore business interruption with similar insurance on commercially reasonable terms were unsuccessful. This lack of insurance could adversely affect our results of operations.

Our decision to pursue a sale of most of our E&P assets is expected to be dilutive to earnings, could have an adverse impact on our results of operations and may not yield the benefits that we expect. On November 1, 2006, we announced our decision to pursue a sale of all of our E&P assets, excluding those assets located in the Appalachian Basin. We expect that a sale of our E&P assets would reduce future earnings in the near term. Although we expect that shareholder value would increase over time, we can give no assurance that this will occur. While our management believes it would be able to execute any sale or sales by mid-2007, we may not be able to sell our E&P assets within the expected time frame. If we sell our E&P assets, we cannot be certain of the price we would receive or the impact that such a sale and the use of proceeds from any sale would have on our results of operations. We may also incur significant costs or be required to record certain charges in connection with any sale and in connection with transactions related to the deployment of the proceeds from any sale.

Additionally, uncertainty about the effect of the proposed disposition may have an adverse effect on the Company, particularly our E&P business. Although we have taken steps to reduce any adverse effects, including providing retention agreements for employees, these uncertainties may impair our ability to attract, retain and motivate key personnel and could cause partners, customers, suppliers and others that deal with our E&P business to seek to change future business relationships. Our E&P business could be harmed if, despite our retention efforts, key employees depart as a result of the proposed disposition.

An inability to access financial markets could affect the execution of our business plan. Dominion and our Virginia Power and CNG subsidiaries rely on access to short-term money markets, longer-term capital markets and banks as significant sources of liquidity for capital requirements and collateral requirements related to hedges of future gas and oil production not satisfied by the cash flows from our operations. Management believes that Dominion and our subsidiaries 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, Dominion s senior unsecured debt is rated BBB, positive outlook, by Standard & Poor s Ratings Services (Standard & Poor s); Baa2, stable outlook, by Moody s Investors Services (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 per share. A reduction in Dominion s credit ratings or the credit ratings of our Virginia Power and CNG subsidiaries by Standard & Poor s, Moody s or Fitch could increase our borrowing costs and adversely affect operating results and could require us to post additional collateral in connection with some of our price risk management activities.

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 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.

ITEM 2. PROPERTIES

We own our principal executive office and two other corporate offices, in Richmond, Virginia. We also lease corporate offices in other cities in which our subsidiaries operate.

Our assets consist primarily of our investments in our subsidiaries, the principal properties of which are described below and in Item 1. Business.

Substantially all of our electric utility s property is subject to the lien of the mortgage securing its 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. Certain of our nonutility generation facilities are also subject to liens.

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The following information detailing our gas and oil operations includes the activities of the Dominion E&P segment and the production activity of Dominion Transmission, Inc., which is included in the Dominion Energy segment:

COMPANY-OWNED PROVED GAS AND OIL RESERVES

Estimated net quantities of proved gas and oil reserves at December 31 of each of the last three years were as follows:

	2006 Proved Developed	2006 Total Proved	2005 Proved Developed	2005 Total Proved	2004 Proved Developed	2004 Total Proved
Proved gas reserves (bcf)						
U.S.	3,424	4,961	3,605	4,856	3,591	4,814
Canada	132	175	101	106	94	96
Total proved gas reserves	3,556	5,136	3,706	4,962	3,685	4,910
Proved oil reserves (000 bbl)						
U.S.	173,718	216,849	145,735	198,602	102,152	144,007
Canada	7,061	15,410	7,154	19,096	11,840	20,055
Total proved oil reserves	180,779	232,259	152,889	217,698	113,992	164,062
Total proved gas and oil reserves (bcfe)	4,640	6,530	4,623	6,268	4,369	5,894

bcf = billion cubic feet

bbl = barrel

bcfe = billion cubic feet equivalent

Certain of our subsidiaries file Form EIA-23 with the DOE which reports gross proved reserves, including the working interest shares of other owners, for properties operated by such subsidiaries. The proved reserves reported in the table above represent our share of proved reserves for all properties, based on our ownership interest in each property. For properties we operate, the difference between the proved reserves reported on Form EIA-23 and the gross reserves associated with the Company-owned proved reserves reported in the table above, does not exceed five percent. Estimated proved reserves as of December 31, 2006 are based upon studies for each of our properties prepared by our staff engineers and audited by Ryder Scott Company, L.P. Calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC guidelines.

QUANTITIES OF GAS AND OIL PRODUCED

Quantities of gas and oil produced during each of the last three years follow:

	2006	2005	2004
Gas production (bcf)			
U.S.	302	275	312
Canada	16	15	36
Total gas production	318	290	348
Oil production (000 bbl)			
U.S.	23,923	14,714	11,258
Canada	1,024	861	2,525
Total oil production	24,947	15,575	13,783
Total gas and oil production (bcfe)	467	383	431

The average realized price per thousand cubic feet (mcf) of gas with hedging results (including transfers to other Dominion operations at market prices) during the years 2006, 2005 and 2004 was $4.41, $4.79 and $4.14, respectively. The respective average realized prices without hedging results per mcf of gas produced were $6.67, $8.01 and $5.77. The respective average realized prices for oil with hedging results were $33.42, $30.46 and $25.22 per barrel and the respective average realized prices without hedging results were $54.49, $49.48 and $35.49 per barrel. The average production (lifting) cost per mcf equivalent of gas and oil produced (as calculated per SEC guidelines) during the years 2006, 2005 and 2004 was $1.18, $1.16 and $0.91, respectively.

ACREAGE

Gross and net developed and undeveloped acreage at December 31, 2006 was:

(thousands)	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
U.S.	4,381	2,782	2,939	1,614
Canada	643	453	469	401
Total	5,024	3,235	3,408	2,015

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NET WELLS DRILLED IN THE CALENDAR YEAR

The number of net wells completed during each of the last three years follows:

	2006	2005	2004
Exploratory:			
U.S.			
Productive	6	6	7
Dry	3	6	7
Total U.S.	9	12	14
Canada			
Productive	33		34
Dry	4		7
Total Canada	37		41
Total Exploratory	46	12	55
Development:			
U.S.			
Productive	1,039	909	921
Dry	33	34	17
Total U.S.	1,072	943	938
Canada			
Productive	31	59	36
Dry	4	5	3
Total Canada	35	64	39
Total Development	1,107	1,007	977
Total wells drilled (net):	1,153	1,019	1,032

As of December 31, 2006, 148 gross (91 net) wells were in the process of being drilled, including wells temporarily suspended.

Productive Wells

The number of productive gas and oil wells in which our subsidiaries had an interest at December 31, 2006, follows:

	Gross	Net
Gas wells:		
U.S.	23,784	17,219
Canada	607	405
Total gas wells	24,391	17,624
Oil wells:		
U.S.	1,850	617
Canada	390	147
Total oil wells	2,240	764

The number of productive wells includes 227 gross (168 net) multiple completion gas wells and 17 gross (11 net) multiple completion oil wells. Wells with multiple completions are counted only once for productive well count purposes.

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POWER GENERATION

We generate electricity for sale on a wholesale and a retail level. We can supply electricity demand either from our generation facilities or through purchased power contracts when needed. The following table lists Dominion Generation s generating units and capability, as of December 31, 2006:

Plant	Location	Primary Fuel Type	Net Summer Capability (Mw)
Utility Generation			
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
Purchased Capacity			2,076
Total Utility Generation			17,628
Merchant Generation			
Millstone	Waterford, CT	Nuclear	1,951(e)
Kewaunee	Kewaunee, WI	Nuclear	556
Kincaid	Kincaid, IL	Coal	1,158
Brayton Point	Somerset, MA	Coal	1,122
State Line	Hammond, IN	Coal	515
Salem Harbor	Salem, MA	Coal	314
Morgantown	Morgantown, WV	Coal	25(f)
Salem Harbor	Salem, MA	Oil	440
Brayton Point	Somerset, MA	Oil	438
Fairless (CC)	Fairless Hills, PA	Gas	1,076(c)

Elwood (CT)	Elwood, IL	Gas	712(g)
Armstrong (CT)	Shelocta, PA	Gas	625(h)
Troy (CT)	Luckey, OH	Gas	600(h)
Manchester (CC)	Providence, RI	Gas	432
Pleasants (CT)	St. Mary s, WV	Gas	313(h)
Other	Various	Various	17
Total Merchant Generation			10,294
Total Capacity			**27,922**

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

(a) Excludes 11.6 percent undivided interest owned by Old Dominion Electric Cooperative (ODEC).
(b) Excludes 50 percent undivided interest owned by ODEC.
(c) Includes generating units that we operate under leasing arrangements.
(d) Excludes 40 percent undivided interest owned by Allegheny Generating Company, a subsidiary of Allegheny Energy, Inc.
(e) Excludes 6.53 percent undivided interest in Unit 3 owned by Massachusetts Municipal Wholesale Electric Company and Central Vermont Public Service Corporation.
(f) Excludes 50 percent partnership interest owned by Cogen Technologies Morgantown, Ltd. and Hickory Power Corporation.
(g) Excludes 50 percent partnership interest owned by Peoples Elwood LLC.
(h) In December 2006, we reached an agreement to sell these facilities. The sale is expected to close in the first quarter of 2007.

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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. 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 *Regulation* in Item 1. Business, *Future Issues and Other Matters* in MD&A, and Note 23 to our Consolidated Financial Statements for additional information on various environmental, rate matters and other regulatory proceedings to which we are a party.

In March 2006, Peoples and Equitable Resources, Inc. (Equitable) filed a joint petition with the Pennsylvania Commission seeking approval of the purchase by Equitable of all 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 February 2007, the administrative law judge for the Pennsylvania Commission entered an initial decision approving a proposed joint settlement and recommending approval of the sale in Pennsylvania.

Before being acquired by us, Louis Dreyfus Natural Gas Corp. (Louis Dreyfus) was one of numerous defendants in a lawsuit consolidated and now pending in the 93rd Judicial District Court in Hidalgo County, Texas. The lawsuit alleges that gas wells and related pipeline facilities operated by Louis Dreyfus, and other facilities operated by other defendants, caused an underground hydrocarbon plume in McAllen, Texas. In April 2006, we entered into a settlement agreement with the plaintiffs resolving all of their claims against us. In May 2006, the plaintiffs non-suited Dominion with prejudice, resulting in the dismissal of the case. We remain subject, however, to a cross-claim and an indemnity claim with certain of the other defendants that were not a party to our settlement with the plaintiffs. Neither claim is material and we do not expect the resolution of these remaining claims or the settlement to have a material adverse effect on the results of operations or financial condition.

In July 1997, Jack Grynberg brought suit against CNG Producing Company, predecessor to Dominion Exploration & Production, Inc. (DEPI), and several of its affiliates. (There are 73 defendants in this case.) The suit seeks damages for alleged fraudulent mis-measurement of gas volumes and underreporting of gas royalties from gas production taken from federal leases. The suit was consolidated with approximately 360 other cases in the U.S. District Court for the District of Wyoming. Parts of Mr. Grynberg s claims were dismissed on the basis that they overlapped with Mr. Wright s claims, which are noted below. Mr. Grynberg has filed an appeal. In October 2006, Judge Downes issued an order dismissing all claims against DEPI and its affiliates on the jurisdictional grounds that Mr. Grynberg has failed to meet his burden to prove he is the original source of the claims being asserted under the False Claims Act. It is expected that Mr. Grynberg will appeal this order.

In April 1998, Harrold E. (Gene) Wright filed suit against DEPI (formerly known as CNG Producing Company), a subsidiary of CNG, and numerous other companies under the False Claims Act. Mr. Wright alleged various fraudulent valuation practices in the payment of royalties due under federal oil and gas leases. Shortly after filing, this case was consolidated under the Federal Multidistrict Litigation rules with the Grynberg case noted above. A substantial portion of the claim against us was resolved by settlement in late 2002. The case was remanded back to the U.S. District Court for the Eastern District of Texas, which denied our motion to dismiss on jurisdictional grounds in January 2005. Discovery in this matter is currently underway.

In September 2006, DTI signed a Consent Order and Agreement with the Pennsylvania Department of Environmental Protection (PADEP) which supercedes a 1990 COA between the parties and has paid a penalty of $850,000. This COA was entered into as part of the settlement of an enforcement action with the PADEP and resolution of lease breaches with the Department of Conservation and Natural Resources.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

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EXECUTIVE OFFICERS OF THE REGISTRANT

Name and Age	Business Experience Past Five Years
Thomas F. Farrell, II (52)	President and Chief Executive Officer (CEO) of Dominion Resources, Inc. (DRI) from January 2006 to date; Chairman of the Board of Directors and CEO of Virginia Electric and Power Company (VP) from February 2006 to date; Chairman of the Board of Directors, President and CEO of Consolidated Natural Gas Company (CNG) from January 2006 to date; Director of DRI from March 2005 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.
Thomas N. Chewning (61)	Executive Vice President and Chief Financial Officer (CFO) of DRI from May 1999 to date; Executive Vice President and CFO of CNG from January 2000 to date; Executive Vice President and CFO of VP from February 2006 to date.
Eva S. Hardy (62)	Executive Vice President External Affairs & Corporate Communications of DRI and CNG from January 2007 to date; Senior Vice President External Affairs & Corporate Communications of DRI from May 1999 to December 2006 and of CNG from September 1999 to December 2006.
Jay L. Johnson (60)	Executive Vice President of DRI and CNG from December 2002 to date; President and COO Delivery of VP from February 2006 to date; President and CEO of VP from December 2002 to January 2006; 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 (CAO) of DRI from January 2002 to December 2002; President of Dominion Resources Services, Inc. (DRS) from October 2002 to January 2003.
Duane C. Radtke (58)	Executive Vice President of DRI and CNG from April 2001 to date.
David A. Christian (52)	Senior Vice President Nuclear Operations and Chief Nuclear Officer of VP from April 2000 to date.
Mary C. Doswell (48)	Senior Vice President and CAO of DRI from January 2003 to date; President and CEO of DRS from January 2004 to date; President of DRS from January 2003 to December 2003; Vice President Billing and Credit of VP from October 2001 to December 2002.
G. Scott Hetzer (50)	Senior Vice President and Treasurer of DRI from May 1999 to date; Senior Vice President and Treasurer of VP and CNG from January 2000 to date.
Steven A. Rogers (45)	Senior Vice President and Chief Accounting Officer of DRI, VP and CNG from January 2007 to date; Senior Vice President and Controller of DRI and CNG from April 2006 to December 2006; Senior Vice President (Principal Accounting Officer) (PAO) of VP 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.
James L. Sanderlin (65)	Senior Vice President Law of DRI from September 1999 to date; Senior Vice President Law of CNG from January 2000 to date.
James F. Stutts (62)	Senior Vice President and General Counsel of DRI, VP and CNG from January 2007 to date; Vice President and General Counsel of DRI from September 1997 to December 2006; Vice President and General Counsel of VP from January 2002 to December 2006; Vice President and General Counsel of CNG from January 2000 to December 2006.

Any service listed for VP, CNG, DRS and DEI reflects service at a subsidiary of DRI.

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PART II

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

Our common stock is listed on the New York Stock Exchange. At December 31, 2006, there were approximately 162,000 registered shareholders, including approximately 68,000 certificate holders. Restrictions on our payment of dividends are discussed in Note 21 to our Consolidated Financial Statements. Quarterly information concerning stock prices and dividends is disclosed in Note 30 to our Consolidated Financial Statements.

During 2006, we issued 120 shares of common stock to a former employee as a deferred payment under a 1985 perform-

ance achievement plan. These shares were not registered under the Securities Act of 1933 (Securities Act). The issuance of this stock did not involve a public offering, and is therefore exempt from registration under the Securities Act.

The following table presents certain information with respect to our common stock repurchases during the fourth quarter of 2006.

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[2]	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased under the Plans or Program
10/1/06 10/31/06	1,947	$ 77.81	N/A	21,275,000 shares/$ 1.72 billion
11/1/06 11/30/06	503,270	$ 80.88	500,000	20,775,000 shares/$ 1.68 billion
12/1/06 12/31/06	5,037,894	$ 89.35[3]	5,036,428	15,738,572 shares/$ 1.23 billion
Total	5,543,111	$ 88.57[4]	5,536,428	15,738,572 shares/$ 1.23 billion

(1) Amount includes registered shares tendered by employees to satisfy tax withholding obligations on vested restricted stock.
(2) In February 2005, Dominion s Board of Directors authorized the repurchase of up to the lesser of 25 million shares or $2.0 billion of Dominion s outstanding common stock.
(3) Includes shares repurchased under an accelerated share repurchase agreement as discussed in Note 20 to our Consolidated Financial Statements.
(4) Represents the weighted average price paid per share during the fourth quarter of 2006.

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ITEM 6. SELECTED FINANCIAL DATA

(millions, except per share amounts)	**2006[1]**	2005[2]	2004[3]	2003[4]	2002
Operating revenue	**$ 16,482**	$ 17,971	$ 13,929	$ 12,035	$ 10,191
Income from continuing operations before cumulative effect of changes in accounting principles	**1,563**	1,047	1,273	942	1,364
Loss from discontinued operations, net of tax[5]	**(183)**	(8)	(24)	(635)	(2)
Cumulative effect of changes in accounting principles, net of tax		(6)		11	
Net income	**1,380**	1,033	1,249	318	1,362
Income from continuing operations before cumulative effect of changes in accounting principles per common share basic	**4.47**	3.06	3.87	2.97	4.85
Net income per common share basic	**3.95**	3.02	3.80	1.00	4.85
Income from continuing operations before cumulative effect of changes in accounting principles per common share diluted	**4.45**	3.04	3.85	2.95	4.83
Net income per common share diluted	**3.93**	3.00	3.78	1.00	4.82
Dividends paid per share	**2.76**	2.68	2.60	2.58	2.58
Total assets	**49,269**	52,660	45,418	43,546	39,239
Long-term debt[6]	**14,791**	14,653	15,507	15,776	12,060
Preferred securities of subsidiary trusts[6]					1,397

(1) Includes a $164 million after-tax impairment charge resulting from the classification of three of our natural gas-fired merchant generation peaking facilities (Peaker facilities) as held for sale and a $104 million after-tax charge resulting from the write-off of certain regulatory assets related to the pending sale of two of our regulated gas distribution subsidiaries. See Note 9 to our Consolidated Financial Statements.

(2) Includes a $272 million after-tax loss related to the discontinuance of hedge accounting for certain gas and oil hedges, resulting from an interruption of gas and oil production in the Gulf of Mexico caused by Hurricanes Katrina and Rita. 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.

(3) 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 $61 million after-tax loss related to the discontinuance of hedge accounting for certain oil hedges, resulting from an interruption of oil production in the Gulf of Mexico caused by Hurricane Ivan, and subsequent changes in the fair value of those hedges during the third quarter.

(4) Includes $122 million of after-tax incremental restoration expenses associated with Hurricane Isabel. Also in 2003, we adopted 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), which resulted in the recognition of the cumulative effect of changes in accounting principles.

(5) Reflects the net impact of our discontinued operations resulting from the pending sale of the Peaker facilities and the net impact of our discontinued telecommunications operations that were sold in May 2004. See Note 9 to our Consolidated Financial Statements.

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

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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 our results of operations and general financial condition. MD&A should be read in conjunction with our Consolidated Financial Statements. The terms Dominion, Company, we, our and us are used throughout this report and, depending on the context of its 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

The reader will find the following information in our MD&A:

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, production delays 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;
- 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;
- Changes in our ability to recover investments made under traditional regulation through rates;
- Receipt of approvals for and timing of closing dates for acquisitions and divestitures, including our divestiture of The Peoples Natural Gas Company (Peoples) and Hope Gas, Inc. (Hope) and any divestiture of our exploration and production (E&P) business;

- Risks associated with any realignment of our operating assets, including the potential dilutive effect on earnings in the near term, costs associated with any sale of our E&P business and the costs and reinvestment risks related to deployment of proceeds from any sale;
- Political and economic conditions, including the threat of domestic terrorism, inflation and deflation;
- Completing the divestiture of investments held by our financial services subsidiary, Dominion Capital, Inc. (DCI);
- Additional risk exposure associated with the termination of business interruption and offshore property damage insurance related to our E&P operations and our inability to replace such insurance on commercially reasonable terms; and
- Changes in rules for regional transmission organizations (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.

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

Dominion is a fully integrated gas and electric holding company headquartered in Richmond, Virginia. Our strategy is to be a leading provider of electricity, natural gas and related services to customers in the eastern region of the United States (U.S.). Our portfolio of assets includes approximately:

- 28,000 megawatts (Mw) of generation capacity;
- 7,800 miles of interstate natural gas transmission, gathering and storage pipeline;
- 6,000 miles of electric transmission lines;
- 55,000 miles of electric distribution lines in Virginia and North Carolina;
- 6.5 trillion cubic feet equivalent of proved gas and oil reserves; and
- An underground natural gas storage system with 979 billion cubic feet of capacity.

Our businesses are managed through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion E&P. 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.

Dominion Delivery includes our regulated electric and gas distribution and customer service businesses, as well as nonregulated retail energy marketing operations. Our electric distribution operations serve residential, commercial, industrial and governmental customers in Virginia and northeastern North Carolina. Our gas distribution operations serve residential, commercial and industrial gas sales and transportation customers in Ohio, Pennsylvania and West Virginia. Our nonregulated retail energy marketing operations market gas, electricity and related products and services to residential, small commercial and industrial customers in the Northeast, Mid-Atlantic and Midwest.

Revenue provided by our electric and gas distribution operations is based primarily on rates established by state regulatory authorities and state law. The profitability of these businesses is dependent on their 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). Income from retail energy marketing operations varies in connection with changes in weather and commodity prices, as well as the acquisition and loss of customers.

In March 2006, we entered into an agreement with Equitable Resources, Inc. to sell two of our wholly-owned regulated gas distribution subsidiaries, Peoples and 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 expected to close by the end of second quarter of 2007, subject to state regulatory approvals in Pennsylvania and West Virginia, as well as approval under the Hart-Scott-Rodino Act.

Dominion Energy includes our regulated electric transmission, natural gas transmission pipeline and storage businesses and the Cove Point liquefied natural gas (LNG) import and storage facility. It also includes gathering and extraction activities, as well as certain Appalachian natural gas production. Dominion Energy includes producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage, associated gas trading and results of certain energy trading activities exited in December 2004. The electric transmission business serves 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 PJM wholesale electricity markets. The gas transmission pipeline and storage business serves our gas distribution businesses and other customers in the Northeast, Mid-Atlantic and Midwest.

Revenue provided by our regulated electric and gas transmission operations and the LNG facility is based primarily on rates established by the Federal Energy Regulatory Commission

(FERC). The profitability of these businesses 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.

Earnings from Dominion Energy s nonregulated businesses are subject to variability associated with changes in commodity prices. Dominion Energy s nonregulated businesses use physical and financial arrangements to attempt to hedge this price risk. Certain hedging and trading activities may require cash deposits to satisfy collateral requirements. Variability in earnings also results from changes in operating and maintenance expenditures (including labor and benefits).

Dominion Generation includes the generation operations of our electric utility and merchant fleet and utility energy supply, energy marketing and price risk management activities for our generation assets. Our generation mix is diversified and includes coal, nuclear, gas, oil, hydro and purchased power. The generation facilities of our electric utility fleet are located in Virginia, West Virginia and North Carolina. The generation facilities of our merchant fleet are located in Connecticut, Illinois, Indiana, Massachusetts, Ohio, Pennsylvania, Rhode Island, West Virginia and Wisconsin.

Dominion 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* under *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 provided by the merchant fleet relates to changes in market-based prices received for electricity and the demand for electricity, which is primarily weather driven. We manage price volatility by hedging a substantial portion of our expected sales. Variability also results from changes in the cost of fuel consumed, labor and benefits and the timing, duration and costs of scheduled and unscheduled outages.

In December 2006, we reached an agreement with an entity jointly owned by Tenaska Power Fund, L.P. and Warburg Pincus LLC to sell three of our natural gas-fired merchant generation peaking facilities (Peaker facilities). Peaking facilities are used during times of high electricity demand, generally in the summer months. 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 sale is expected to result in proceeds of approximately $256 million and should close in the first quarter of 2007, pending regulatory approval by FERC. We have obtained approval from the Federal Trade Commission. No state regulatory approvals are required.

We offered the facilities for sale following a review of our portfolio of assets. We have decided not to sell a fourth merchant generation facility, State Line, a 515 Mw coal-fired facility in Hammond, Indiana.

Dominion E&P includes our gas and oil exploration, development and production business. Operations are 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, as well as the Western Canadian Sedimentary Basin.

Dominion E&P generates income from the sale of natural gas and oil we produce from our reserves. Variability in earnings relates primarily to changes in commodity prices, which are market-based, and production volumes, which are impacted by numerous factors including drilling success, timing of development projects and external factors such as storm-related damage caused by hurricanes. We attempt to manage commodity price volatility by hedging a substantial portion of our expected production. These hedging activities may require cash deposits to satisfy collateral requirements.

In November 2006, we announced our decision to pursue the sale of all of our oil and natural gas E&P operations and assets, with the exception of those located in the Appalachian Basin. As of December 31, 2006, our natural gas and oil assets excluding the Appalachian Basin included about 5.5 trillion cubic feet of proved reserves. The Appalachian assets that we would retain constitute approximately 15% of our total reserves as of December 31, 2006.

Corporate includes our corporate, service company and other operations (including unallocated debt), corporate-wide commodity risk management services, the remaining assets of DCI, which are in the process of being divested, the net impact of our discontinued telecommunications operations that were sold in May 2004 and the net impact of the discontinued operations of the Peaker facilities. In addition, Corporate includes 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.

Outlook

A sale of substantially all of our E&P business would allow us to focus on growing our electric generating and energy distribution, transmission and storage businesses and realign our operations and risk profile more closely with our peer investment group of utilities. If a sale is completed, we would use the net cash proceeds to reduce debt and maintain or improve our existing credit ratings. We would also expect to repurchase shares of our common stock and/or acquire select assets to complement our remaining businesses. By redeploying net cash proceeds to debt reduction, stock buybacks and expansion of our remaining businesses, we believe that shareholders would see solid, reliable growth from a complementary set of assets. Our objective is to grow consolidated earnings at a long-term average annual rate of 4 to 6 percent following any E&P sale. Closing of any sale or sales is targeted for mid-2007.

While a sale would likely dilute consolidated earnings per share in the short term, we believe a sale will result in more stable and predictable earnings that are less sensitive to changes in commodity prices, and could result in an increased dividend. Our Board of Directors will address the issue of a possible change in the dividend policy following a sale. In total, we believe that our strategic repositioning, once complete, will provide the necessary platform to enhance shareholder value.

Another important development impacting the future of our Company is the passage of legislation in Virginia that would re-regulate certain elements of our electric utility 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.

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 the Audit Committee of our Board of Directors.

ACCOUNTING FOR DERIVATIVE CONTRACTS AT FAIR VALUE

We use derivative contracts such as futures, swaps, forwards, options and financial transmission rights to buy and sell energy-related commodities and to manage our commodity and financial markets risks. Derivative contracts, with certain exceptions, are subject to fair value accounting and are reported in our Consolidated Balance Sheets at fair value. Accounting requirements for derivatives and related hedging activities are complex and may be subject to further clarification by standard-setting bodies.

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 use of statistical methods. 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. 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 under 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 a contract s estimated fair value.

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

USE OF ESTIMATES IN GOODWILL IMPAIRMENT TESTING

As of December 31, 2006, we reported $4.3 billion of goodwill in our Consolidated Balance Sheet, a significant portion of which resulted from the acquisition of Consolidated Natural Gas Company (CNG) in 2000. Substantially all of this goodwill is allocated to our Generation, Transmission, Delivery and E&P reporting units. In April of each year, we test our goodwill for potential impairment, and perform additional tests more frequently if impairment indicators are present. The 2006, 2005 and 2004 annual tests did not result in the recognition of any goodwill impairment, as the estimated fair values of our reporting units exceeded their respective carrying amounts.

We estimate the fair value of our reporting units by using a combination of discounted cash flow analyses, based on our internal five-year strategic plan, and other valuation techniques that use multiples of earnings for peer group companies and analyses of recent business combinations involving peer group companies. These calculations are dependent on subjective factors such as our estimate of future cash flows, the selection of appropriate discount and growth rates, and the selection of peer group companies and recent transactions. These underlying assumptions and estimates are made as of a point in time; subsequent modifications, particularly changes in discount rates or growth rates inherent in our estimates of future cash flows, could result in a future impairment of goodwill. Although we have consistently applied the same methods in developing the assumptions and estimates that underlie the fair value calculations, such as estimates of future cash flows, and based those estimates on relevant information available at the time, such cash flow estimates are highly uncertain by nature and may vary significantly from actual results. If the estimates of future cash flows used in the most recent annual test had been 10% lower, the resulting fair values would have still been greater than the carrying values of each of those reporting units tested, indicating that no impairment was present.

USE OF ESTIMATES IN LONG-LIVED ASSET IMPAIRMENT TESTING

Impairment testing for an individual or group of long-lived assets or for intangible assets with definite lives is required when circumstances indicate those assets may be impaired. When an asset s carrying amount exceeds the undiscounted estimated future cash flows associated with the asset, the asset is considered impaired to the extent that the asset s fair value is less than its carrying amount. Performing an impairment test on long-lived assets involves judgment in areas such as identifying circumstances that indicate an impairment may exist; identifying and grouping affected assets; and developing the undiscounted and discounted estimated future cash flows (used to estimate fair value in the absence of market-based value) associated with the asset, including probability weighting such cash flows to reflect expectations about possible variations in their amounts or timing and the selection of an appropriate discount rate. Although our cash flow estimates are based on relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. For example, estimates of future cash flows would contemplate factors such as the expected use of the asset, including future production and sales levels, and expected fluctuations of prices of commodities sold and consumed.

In conjunction with the results of a review of our portfolio of assets, the Peaker facilities, with a combined carrying amount of $504 million, were marketed for sale in the third quarter of 2006. An impairment analysis performed in the third quarter of 2006 indicated that the carrying amount of each of the Peaker facilities was recoverable as the expected undiscounted cash flows, probability weighted to reflect both continued use and possible sale scenarios, exceeded the carrying amount. In December 2006, we reached an agreement to sell the Peaker facilities and accordingly, we reduced their carrying amounts to fair value less cost to sell and classified them as held for sale in our Consolidated Balance Sheet. Also in the fourth quarter of 2006, in conjunction with the review of our assets, a decision was made to no longer pursue the development of a gas transmission pipeline project with capitalized construction costs of $28 million. The pipeline project was previously tested for impairment during 2005. The results of our analysis in 2005 indicated that this asset was not impaired. Impairment charges of $280 million ($181 million after-tax) were recorded in December 2006 related to the Peaker facilities and the transmission pipeline project.

Also in 2006, a natural gas-fired merchant generation facility project, with a carrying amount of $460 million, was tested for impairment. The results of our analysis indicated that this carrying amount, as well as the estimated cost to complete, were recoverable.

In 2005, we tested a group of gas and steam electric turbines held for future development with a carrying amount of $187 million for impairment. The results of our analysis indicated that this carrying amount was recoverable. In 2004, we did not test any significant long-lived assets or asset groups for impairment as no circumstances arose that indicated an impairment may exist.

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 $109 million, $102 million and $91 million, respectively, of accretion, and expect to incur $82 million in 2007.

A significant portion of our AROs relates to the future decommissioning of our nuclear facilities. At December 31, 2006, nuclear decommissioning AROs, which are reported in the Dominion Generation segment, totaled $1.4 billion, representing approximately 73% 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 utility and merchant nuclear plants. We obtained updated cost studies for all of our nuclear plants in 2006 which generally 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 0.72% due to projected reductions in both general and decommissioning specific inflation rates, resulting in a $481 million decrease in our nuclear decommissioning AROs.

EMPLOYEE BENEFIT PLANS

We sponsor noncontributory defined benefit pension plans and other postretirement benefit plans for eligible active employees, retirees and qualifying dependents. The projected costs of providing benefits under these plans are dependent, in part, on historical information such as employee demographics, the level of contributions made to the plans and earnings on plan assets. Assumptions about the future, including the expected rate of return on plan assets, discount rates applied to benefit obligations and the anticipated rate of increase in health care costs and participant compensation, also have a significant impact on employee benefit costs. The impact on pension and other postretirement benefit plan obligations associated with changes in these factors is generally recognized in our Consolidated Statements of Income over the remaining average service period of plan participants rather than immediately.

The expected long-term rates of return on plan assets, discount rates and medical cost trend rates are critical assumptions. We determine the expected long-term rates of return on plan assets for pension plans and other postretirement benefit plans by using a combination of:

- Historical return analysis to determine expected future risk premiums;
- Forward-looking return expectations derived from the yield on long-term bonds and the price earnings ratios of major stock market indices;
- Expected inflation and risk-free interest rate assumptions; and
- Investment allocation of plan assets. Effective September 1, 2006, the strategic target asset allocation for our pension fund is 34% U.S. equity securities, 12% non-U.S. equity securities, 22% debt securities, 7% real estate and 25% other, such as private equity investments. Prior to September 1, 2006, the strategic target asset allocation for our pension fund was 45% U.S. equity securities, 8% non-U.S. equity securities, 22% debt securities and 25% other, such as real estate and private equity investments.

Assisted by an independent actuary, we develop assumptions, which are then compared to the forecasts of other independent investment advisors to ensure reasonableness. An internal committee selects the final assumptions. We calculated our pension cost using an expected return on plan assets assumption of 8.75% for 2006, 2005 and 2004. We calculated our 2006 and 2005 other postretirement benefit cost using an expected return on plan assets assumption of 8.00% compared to 7.79% for 2004. The rate used in calculating other postretirement benefit cost is lower than the rate used in calculating pension cost because of differences in the relative amounts of various types of investments held as plan assets.

We determine discount rates from analyses performed by a third-party actuarial firm of AA/Aa rated bonds with cash flows matching the expected payments to be made under our plans. The discount rates used to calculate 2006 pension cost and other postretirement benefit cost were 5.60% and 5.50%, respectively, compared to the 6.00% and 6.25% discount rates used to calculate 2005 and 2004 pension and other postretirement benefit costs, respectively. Lower long-term bond yields were the primary reason for the decline in the discount rate from 2005 to 2006. We selected discount rates of 6.20% and 6.10% for determining our December 31, 2006 projected pension and postretirement benefit obligations, respectively.

We establish the medical cost trend rate assumption based on analyses performed by a third-party actuarial firm of various factors including the specific provisions of our medical plans, actual cost trends experienced and projected, and demographics of plan participants. Our medical cost trend rate assumption as of December 31, 2006 is 9.00% and is expected to gradually decrease to 5.00% in later years.

The following table illustrates the effect on cost of changing the critical actuarial assumptions previously discussed, while holding all other assumptions constant:

		Increase in Net Periodic Cost	
Actuarial Assumption (millions, except percentages)	Change in Assumption	Pension Benefits	Other Postretirement Benefits
Discount rate	(0.25)%	$ 13	$ 3
Rate of return on plan assets	(0.25)%	11	2
Healthcare cost trend rate	1%	N/A	30

In addition to the effects on cost, a 0.25% decrease in the discount rate would increase our projected pension benefit obligation by $122 million and would increase our accumulated postretirement benefit obligation by $38 million at December 31, 2006.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, CONTINUED

ACCOUNTING FOR REGULATED OPERATIONS

The accounting for our regulated electric and gas 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. In 2006, $166 million of our regulatory assets were written off as a result of the pending sale of Peoples and Hope since the recovery of those assets is no longer probable. We currently believe the recovery of our remaining regulatory assets is probable. See Notes 2 and 14 to our Consolidated Financial Statements.

ACCOUNTING FOR GAS AND OIL OPERATIONS

We follow the full cost method of accounting for gas and oil E&P activities prescribed by the Securities and Exchange Commission (SEC). Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized and subsequently depleted using the units-of-production method. The depletable base of costs includes estimated future costs to be incurred in developing proved gas and oil reserves, as well as capitalized asset retirement costs, net of projected salvage values. Capitalized costs in the depletable base are subject to a ceiling test prescribed by the SEC. The test limits capitalized amounts to a ceiling the present value of estimated future net revenues to be derived from the production of proved gas and oil reserves, assuming period-end pricing adjusted for any cash flow hedges in place. We perform the ceiling test quarterly, on a country-by-country basis, and would recognize asset impairments to the extent that total capitalized costs exceed the ceiling. In addition, gains or losses on the sale or other disposition of gas and oil properties are not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil attributable to a country.

Our estimate of proved reserves requires a large degree of judgment and is dependent on factors such as historical data, engineering estimates of proved reserve quantities, estimates of the amount and timing of future expenditures to develop the proved reserves, and estimates of future production from the proved reserves. Our estimated proved reserves as of December 31, 2006 are based upon studies for each of our properties prepared by our

staff engineers and audited by Ryder Scott Company, L.P. Calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC guidelines. Given the volatility of natural gas and oil prices, it is possible that our estimate of discounted future net cash flows from proved natural gas and oil reserves that is used to calculate the ceiling could materially change in the near-term.

The process to estimate reserves is imprecise, and estimates are subject to revision. If there is a significant variance in any of our estimates or assumptions in the future and revisions to the value of our proved reserves are necessary, related depletion expense and the calculation of the ceiling test would be affected and recognition of natural gas and oil property impairments could occur. See Notes 2 and 29 to our Consolidated Financial Statements.

INCOME TAXES

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

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 (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). 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.

Other

ACCOUNTING STANDARDS

During 2006, 2005 and 2004, we were required to adopt several new accounting standards, which are discussed in Note 3 to our Consolidated Financial Statements. Our adoption of SFAS No. 158*, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans* on December 31, 2006 affected the comparability of our Consolidated Balance Sheet at December 31, 2006 to prior periods. Under SFAS No. 158, our

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Consolidated Balance Sheet now reflects the overfunded or underfunded status of our defined benefit plans as an asset or a liability, respectively, with previously unrecognized net actuarial gains or losses, prior service costs or credits and transition obligations recognized as a component of either AOCI or regulatory assets or liabilities. See Note 4 to our Consolidated Financial Statements for a discussion of recently issued accounting standards that will be adopted in the future.

DOMINION CLEARINGHOUSE

During the fourth quarter of 2004, we performed an evaluation of our Dominion Clearinghouse (Clearinghouse) trading and marketing operations, which resulted in a decision to exit certain energy trading activities and instead focus on the optimization of our assets. In January 2005, in connection with the reorganization, commodity derivative contracts held by the Clearinghouse were assessed to determine if they contribute to the optimization of our assets. As a result of this review, certain commodity derivative contracts previously designated as held for trading purposes were redesignated as held for non-trading purposes. Under our derivative income statement classification policy described in Note 2 to our Consolidated Financial Statements, all changes in fair value, including amounts realized upon settlement, related to the reclassified contracts were previously presented in operating revenue on a net basis. Upon redesignation as non-trading, all unrealized changes in fair value and settlements related to those derivative contracts that are financially settled are reported in other operations and maintenance expense. In addition, all physically-settled sales contracts are presented in operating revenue and all physically-settled purchase contracts are presented in operating expense in our Consolidated Statements of Income.

RESULTS OF OPERATIONS

Presented below is a summary of our consolidated results:

Year Ended December 31, (millions, except EPS)	2006	$ Change	2005	$ Change	2004
Net Income	$ 1,380	$ 347	$ 1,033	$ (216)	$ 1,249
Diluted earnings per share (EPS)	3.93	0.93	3.00	(0.78)	3.78

Overview

2006 VS. 2005

Net income increased 34% to $1.4 billion. Favorable drivers included increased gas and oil production, higher realized prices from our merchant generation business, an increased contribution from our nonregulated retail energy marketing operations, higher business interruption insurance proceeds received in 2006 than in 2005 and the absence of losses incurred in 2005 due to the discontinuance of hedge accounting for certain gas and oil hedges resulting from hurricane-related interruptions of gas and oil production in the Gulf of Mexico. These favorable drivers were partially offset by an impairment charge related to the Peaker facilities, milder weather in our gas and electric service territories, lower realized gas prices for our E&P operations and a

reduction in gains from sales of emissions allowances held for consumption.

2005 VS. 2004

Our 2005 results were significantly impacted by Hurricanes Katrina and Rita (2005 hurricanes), which struck the Gulf Coast area in late August and late September 2005, respectively. Due to the hurricanes, our production assets in the Gulf of Mexico and, to a lesser extent, southern Louisiana were temporarily shut in. The interruption in gas and oil production resulted in a $272 million after-tax loss related to the discontinuance of hedge accounting for certain gas and oil hedges. Results were also impacted by delays in production caused by damage to third-party downstream infrastructure.

Our 2005 results were also negatively impacted by increased fuel and purchased power expenses incurred by our electric utility operations primarily as a result of higher commodity prices. These negatives were partially offset by higher realized gas and oil prices for our E&P operations, gains on the sale of emissions allowances and a higher contribution from merchant generation operations, primarily reflecting the benefit of two acquisitions during 2005. In January 2005, we completed the acquisition of three fossil-fired power stations with generating capacity of more than 2,700 Mw (Dominion New England) and in July 2005, we completed the acquisition of the 556 Mw Kewaunee nuclear power station (Kewaunee).

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	$ 16,482	$ (1,489)	$ 17,971	$ 4,042	$ 13,929
Operating Expenses					
Electric fuel and energy purchases	3,236	(1,434)	4,670	2,544	2,126
Purchased electric capacity	481	(23)	504	(83)	587
Purchased gas	2,937	(1,004)	3,941	1,014	2,927
Other energy-related commodity purchases	1,022	(369)	1,391	402	989
Other operations and maintenance	3,280	226	3,054	299	2,755
Depreciation, depletion and amortization	1,606	209	1,397	108	1,289
Other taxes	575	(6)	581	62	519
Other income	174	6	168	1	167
Interest and related charges	1,030	64	966	40	926
Income tax expense	920	332	588	(117)	705
Loss from discontinued operations, net of tax	(183)	(175)	(8)	16	(24)

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

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, CONTINUED

2006 VS. 2005

Operating Revenue decreased 8% to $16.5 billion, primarily reflecting:

- A $1.0 billion decrease primarily attributable to lower volumes associated with requirements-based power sales contracts that we are exiting. The effect of this decrease is more than offset by a corresponding decrease in *Electric fuel and energy purchases expense*;
- An $844 million decrease in our producer services business consisting of a decrease in both volumes and prices associated with gas aggregation, partially offset by favorable price changes related to gas marketing activities. The effect of this decrease is partially offset by a corresponding decrease in *Purchased gas expense*;
- A $367 million decrease from regulated gas distribution operations, primarily reflecting a $219 million decrease resulting from the loss of customers to Energy Choice programs and a $270 million decrease associated with milder weather and variations in rates resulting from changes in customer usage patterns, sales mix and other factors, partially offset by a $122 million increase related to the recovery of higher gas prices. The effect of this net decrease was partially offset by a corresponding decrease in *Purchased gas expense*;
- A $308 million decrease in nonutility coal sales, primarily resulting from decreased volumes. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*;
- A $178 million decrease in sales of emissions allowances purchased for resale, reflecting lower prices ($115 million) and lower overall sales volume ($63 million). The effect of this decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*; and
- A $93 million decrease in revenue from sales of gas purchased by E&P operations to facilitate gas transportation and other contracts, primarily due to the impact of netting sales and purchases of gas under buy/sell arrangements associated with the implementation of Emerging Issues Task Force (EITF) Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*.

These decreases were partially offset by:

- A $313 million increase from our merchant generation business, primarily reflecting higher revenue for nuclear operations as a result of higher realized prices and new business from the addition of Kewaunee, which was acquired in July 2005. This increase was partially offset by lower sales volume for fossil plants driven largely by comparably milder weather and lower prices;
- A $235 million increase associated with hedging activities for our merchant generation assets. The effect of this increase is offset by a corresponding increase in *Other operations and maintenance expense*;
- A $188 million increase in sales of gas and oil production, primarily due to higher volumes ($397 million), partially offset by lower prices ($209 million);
- A $184 million increase in gas sales by our nonregulated retail energy marketing operations primarily resulting from increased customer counts ($141 million) and higher contracted sales prices ($43 million);
- A $170 million increase in sales of extracted products, primarily due to increased prices and a contractual change for a portion of our gas production processed by third parties. We now take title to and market the extracted products from this gas;
- An increase of $95 million resulting from higher business interruption insurance revenue received in 2006 related to the 2005 hurricanes ($274 million) versus business interruption revenue received in 2005 ($179 million) related to Hurricane Ivan; and
- An $88 million increase due to a sale of gas inventory by our East Ohio Gas subsidiary related to the implementation of the Standard Service Offer (SSO) pilot program as approved by the Ohio Commission. The SSO was initiated to encourage and assist other suppliers to enter the gas procurement market. By the end of the transition period, we plan to exit the gas merchant function in Ohio and have all customers select an alternate gas supplier. The effect of this increase was offset by a comparable increase in *Purchased gas expense*.

Operating Expenses

Electric fuel and energy purchases expense decreased 31% to $3.2 billion, primarily reflecting the combined effects of:

- A $1.2 billion decrease associated with lower volumes associated with requirements-based power sales contracts, as discussed in *Operating Revenue;*
- A $162 million decrease for our utility generation operations, 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; and
- A $104 million decrease from our merchant generation business, due primarily to lower commodity prices and decreased consumption of fossil fuel, reflecting the effects of milder weather on demand, partially offset by higher replacement power costs incurred due to an increase in scheduled outage days.

Purchased gas expense decreased 25% to $2.9 billion, principally resulting from:

- An $815 million decrease associated with our producer services business, due to lower volumes and prices;
- A $192 million decrease related to regulated gas distribution operations, due to a $252 million decrease associated with milder weather and the migration of additional customers to Energy Choice and a $222 million decrease due to lower average gas prices, partially offset by a $282 million increase related to the recovery of gas costs;
- A $120 million decrease related to E&P operations, as the result of lower volumes and the impact of netting sales and purchases of gas under buy/sell arrangements following the implementation of EITF 04-13, as discussed in *Operating Revenue*; partially offset by
- A $139 million increase associated with nonregulated retail energy marketing operations, primarily due to increased volumes.

Other energy-related commodity purchases expense decreased 27% to $1.0 billion, primarily attributable to the following factors, all of which are discussed in *Operating Revenue*:

- A $237 million decrease in the cost of coal purchased for resale; and
- A $175 million decrease in emissions allowances purchased for resale; partially offset by

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- A $47 million increase related to purchases of oil by E&P operations, reflecting higher market prices ($63 million), partially offset by lower volumes ($16 million) of oil purchases under buy/sell arrangements.

Other operations and maintenance expense increased 7% to $3.3 billion, resulting from:

- A $235 million increase primarily related to hedging activities associated with our generation assets. The effect of this increase is offset by a corresponding increase in *Operating Revenue*;
- A $166 million charge from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope;
- A $105 million increase attributable to higher production handling, transportation and operating costs related to E&P operations;
- A $97 million increase resulting primarily from higher salaries, wages and benefits expenses;
- $91 million of impairment charges related to DCI investments;
- A $79 million increase resulting from Kewaunee, which was acquired in July 2005;
- A $65 million decrease in gains from the sale of emissions allowances held for consumption;
- A $60 million charge to eliminate the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts that sold trust preferred securities;
- A $41 million reduction in proceeds related to financial transmission rights (FTRs) granted by PJM to our utility generation operations. These FTRs are used to offset congestion costs associated with PJM spot market activity, which are included in *Electric fuel and energy purchases expense*;
- A $35 million increase in generation-related outage costs primarily due to an increase in the number of scheduled outages;
- 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 $27 million charge resulting from the cancellation of a pipeline project;

These increases were partially offset by:

- A $62 million benefit resulting from favorable changes in the fair value of certain gas and oil derivatives that were de-designated as hedges following the 2005 hurricanes;
- A $96 million decrease in hedge ineffectiveness expense associated with our E&P operations, primarily due to a decrease in the fair value differential between the delivery location and commodity specifications of derivative contracts held by us as compared to our forecasted gas and oil sales and the increased use of basis swaps;
- A benefit resulting from the absence of the following items recognized in 2005:
  - A $423 million loss related to the discontinuance of hedge accounting for certain gas and oil hedges resulting from an interruption of gas and oil production in the Gulf of Mexico caused by the 2005 hurricanes;
  - A $77 million charge resulting from the termination of a long-term power purchase agreement;
  - A $59 million loss related to the discontinuance of hedge accounting for certain oil derivatives primarily resulting from a delay in reaching anticipated production levels in the Gulf of Mexico, and subsequent changes in the fair value of those derivatives; and
  - A $51 million charge related to credit exposure associated with the bankruptcy of Calpine Corporation; partially offset by
  - A $24 million net benefit resulting from the establishment of certain regulatory assets and liabilities in connection with the settlement of a North Carolina rate case in the first quarter of 2005.

Depreciation, depletion and amortization expense (DD&A) increased 15% to $1.6 billion, largely due to the impact of increased gas and oil production, as well as higher E&P finding and development costs.

Interest expense increased 7% to $1.0 billion principally reflecting the impact of additional borrowings and higher interest rates on variable rate debt.

Loss from discontinued operations increased to $183 million primarily reflecting a $164 million after-tax impairment charge related to the pending sale of the Peaker facilities, whose operating losses were reclassified to discontinued operations in December 2006.

2005 VS. 2004

Operating Revenue increased 29% to $18.0 billion, primarily reflecting:

- A $1.1 billion increase in sales from our merchant generation operations, primarily attributable to the addition of Dominion New England and Kewaunee and a full year of commercial operations at our Fairless Energy power station (Fairless), which began operating in June 2004;
- A $730 million increase related to the designation of certain commodity derivative contracts as held for non-trading purposes effective January 1, 2005. These contracts were previously held for trading purposes as discussed in Note 28 to our Consolidated Financial Statements.

The impact of this change in classification was offset by similar changes in *Other operations and maintenance expense* and *Electric fuel and energy purchases expense;*

- A $588 million increase from gas aggregation activities and nonregulated retail energy marketing operations primarily due to higher gas prices. This increase was largely offset by a corresponding increase in *Purchased gas expense*;
- A $363 million increase from our regulated electric utility operations reflecting a $153 million increase in sales to wholesale customers, a $99 million increase due to the impact of a comparatively higher fuel rate for non-Virginia jurisdictional customers, a $77 million increase primarily due to the impact of favorable weather on customer usage and a $59 million increase from customer growth associated with new customer connections, partially offset by a $25 million decrease due to variations in seasonal rate premiums and discounts. The increase resulting from a comparatively higher fuel rate was more than offset by an increase in *Electric fuel and energy purchases expense*; and
- A $341 million increase from regulated gas distribution operations primarily related to the recovery of higher gas prices.

The effect of this increase was offset by a comparable increase in *Purchased gas expense;*

- A $276 million increase in nonutility coal sales resulting from higher coal prices ($171 million) and increased sales volumes ($105 million). This increase was more than offset by a corresponding increase in *Other energy-related commodity purchases expense*;
- A $110 million increase due to higher natural gas prices related to market-based services for the optimization of transportation and storage assets by our E&P operations, partially offset by the effect of unfavorable price changes on unsettled contracts. This increase was largely offset by a corresponding increase in *Purchased gas expense*;
- A $110 million increase in sales of gas purchased by E&P operations to facilitate gas transportation and satisfy other agreements. This increase was largely offset by a corresponding increase in *Purchased gas expense*;
- An $87 million increase in sales of purchased oil by E&P operations. This increase was more than offset by a corresponding increase in *Other energy-related commodity purchases expense*;
- A $37 million increase in sales of emissions allowances held for resale primarily due to higher prices. This increase was more than offset by a corresponding increase in *Other energy-related commodity purchases expense*.

Operating Expenses

Electric fuel and energy purchases expense increased 120% to $4.7 billion, primarily reflecting the combined effects of:

- A $1.2 billion increase related to the designation of certain commodity derivative contracts as held for non-trading purposes effective January 1, 2005, which were previously held for trading purposes as discussed in *Operating Revenue;*
- A $796 million increase related to utility operations primarily resulting from higher commodity prices including purchased power; and
- A $556 million increase due to the addition of Dominion New England and Kewaunee and a full year of commercial operations at Fairless.

Purchased electric capacity expense decreased 14% to $504 million, as a result of the termination of several long-term power purchase agreements in connection with the purchase of the related generating facilities in 2005 and 2004.

Purchased gas expense increased 35% to $3.9 billion, principally resulting from the following items which are discussed in *Operating Revenue*:

- A $522 million increase associated with gas aggregation activities and nonregulated retail energy marketing operations;
- A $305 million increase associated with regulated gas distribution operations; and
- A $124 million increase related to E&P operations.

Other energy related-commodity purchases expense increased 41% to $1.4 billion, primarily reflecting the following items which are discussed in *Operating Revenue*:

- A $263 million increase in the cost of coal purchased for resale;
- A $91 million increase related to purchases of oil by E&P operations; and
- A $47 million increase in emissions allowances purchased for resale.

Other operations and maintenance expense increased 11% to $3.1 billion, resulting from:

- A $423 million loss related to the discontinuance of hedge accounting for certain gas and oil hedges resulting from an interruption of gas and oil production in the Gulf of Mexico caused by the 2005 hurricanes;
- A $361 million increase due to the addition of Dominion New England and Kewaunee and a full year of commercial operations at Fairless;
- A $193 million increase in salaries and benefits, due to higher incentive-based compensation ($106 million), wages ($43 million) and pension and medical benefits ($44 million);
- A $77 million charge resulting from the termination of a long-term power purchase agreement;
- A $75 million increase in hedge ineffectiveness expense associated with E&P operations, primarily due to an increase in the fair value differential between the delivery location and commodity specifications of our derivative contracts and the delivery location and commodity specifications of our forecasted gas and oil sales;
- A $59 million loss related to the discontinuance of hedge accounting in March 2005 for certain oil hedges primarily resulting from a delay in reaching anticipated production levels in the Gulf of Mexico, and subsequent changes in the fair value of those hedges;
- A $51 million charge related to credit exposure associated with the bankruptcy of Calpine Corporation;
- A $35 million charge related to our investment in and planned divestiture of DCI assets;

These increases were partially offset by the following:

-

A $344 million decrease related to the designation of certain commodity derivative contracts as held for non-trading purposes effective January 1, 2005, which were previously held for trading purposes as discussed in *Operating Revenue*;

- A $186 million benefit related to FTRs;
- A $139 million gain resulting from the sale of emissions allowances held for consumption;
- A $24 million net benefit resulting from the establishment of certain regulatory assets and liabilities in connection with the settlement of a North Carolina rate case in the first quarter of 2005; and
- The net impact 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 in connection with our exit from certain energy trading activities;
  - A $96 million loss related to the discontinuance of hedge accounting for certain oil hedges resulting from an interruption of oil production in the Gulf of Mexico caused by Hurricane Ivan, and subsequent changes in the fair value of those hedges during the third quarter;
  - A $72 million charge associated with the impairment of retained interests from mortgage securitizations and venture capital and other equity investments held by DCI; and
  - A $71 million net charge resulting from the termination of certain long-term power purchase agreements; partially offset by

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- A $120 million benefit due to favorable changes in the fair value of certain oil options related to E&P operations.

Depreciation, depletion and amortization expense increased 8% to $1.4 billion, largely due to incremental depreciation and amortization expense resulting from our acquisition of the Dominion New England power plants and other property additions.

Other taxes increased 12% to $581 million, primarily due to higher property taxes resulting from the Dominion New England power plants and higher severance taxes associated with increased commodity prices.

Loss from discontinued operations reflects charges related to the Peaker facilities, whose operating losses were reclassified to discontinued operations as a result of their pending sale.

SEGMENT RESULTS OF OPERATIONS

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit or loss. Presented below is a summary of contributions by our operating segments to net income:

Year Ended December 31,	2006 Net Income	2006 Diluted EPS	2005 Net Income	2005 Diluted EPS	2004 Net Income	2004 Diluted EPS
(millions, except EPS)						
Dominion Delivery	$ 438	$ 1.25	$ 448	$ 1.30	$ 466	$ 1.41
Dominion Energy	360	1.02	319	0.93	190	0.57
Dominion Generation	537	1.53	416	1.20	533	1.61
Dominion E&P	680	1.93	565	1.64	595	1.80
Primary operating segments	2,015	5.73	1,748	5.07	1,784	5.39
Corporate	(635)	(1.80)	(715)	(2.07)	(535)	(1.61)
Consolidated	$ 1,380	$ 3.93	$ 1,033	$ 3.00	$ 1,249	$ 3.78

Dominion Delivery

Presented below are operating statistics related to Dominion Delivery s 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
Gas throughput (bcf):					
Gas sales	94	(28)	131	3	127
Gas transportation	240		241	(1)	244
Heating degree days (gas service area)(3)	5,190	(12)	5,899	3	5,716
Average gas delivery customer accounts(4):					
Gas sales	858	(17)	1,030	3	996
Gas transportation	830	26	661	(5)	693
Average nonregulated retail energy marketing customer accounts(4)	1,354	17	1,162	(13)	1,341

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) Thirteen-month average, in thousands.

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

2006 VS. 2005

(millions, except EPS)	Increase (Decrease) Amount	EPS
Regulated electric sales:		
Weather	$ (29)	$ (0.08)
Customer growth	11	0.03
Other(1)	15	0.04
Regulated gas sales weather	(26)	(0.07)
Major storm damage and service restoration	(18)	(0.05)
Interest expense(2)	(11)	(0.03)
Other margins gas(3)	(10)	(0.03)
2005 North Carolina rate case settlement	(6)	(0.02)
Nonregulated retail energy marketing operations(4)	57	0.17
Other	7	0.02
Share dilution		(0.03)
Change in net income contribution	$ (10)	$ (0.05)

(1) Attributable to rate variations from changes in customer usage patterns and sales mix, and other factors.
(2) Principally reflects additional intercompany borrowings and higher interest rates on those borrowings.
(3) Largely reflects reduced customer usage at our regulated gas distribution operations, due in part to price sensitivity.
(4) Largely reflects higher electric and gas margins due to higher rates, increased gas customers and lower commodity costs.

2005 VS. 2004

(millions, except EPS)	Increase (Decrease) Amount	EPS
Interest expense(1)	$ (25)	$ (0.08)
Salaries, wages and benefits expense	(14)	(0.04)
Depreciation expense	(10)	(0.03)
Bad debt expense(2)	(7)	(0.02)
Regulated electric sales:		
Weather	14	0.04
Customer growth	11	0.03
Regulated gas sales weather	8	0.02
2005 North Carolina rate case settlement	6	0.02
Other	(1)	
Share dilution		(0.05)
Change in net income contribution	$ (18)	$ (0.11)

(1) Represents the impact of additional long-term affiliate borrowings and variable rate debt, higher interest rates on affiliate borrowings and prepayment penalties resulting from the early redemption of debt.
(2) Higher bad debt expense primarily reflects the absence of a 2004 reduction in reserves.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, CONTINUED

Dominion Energy

Presented below are operating statistics related to Dominion Energy s operations:

Year Ended December 31,	2006	% Change	2005	% Change	2004
Gas transportation throughput (bcf)	650	(18)%	794	13%	704

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

2006 VS. 2005

(millions, except EPS)	Increase (Decrease) Amount	EPS
Gas transmission:		
Other margins(1)	$ 39	$ 0.11
Rate settlement(2)	(13)	(0.04)
Producer services(3)	23	0.06
Other	(8)	(0.02)
Share dilution		(0.02)
Change in net income contribution	$ 41	$ 0.09

(1) Higher margins primarily from extracted products and short-term transportation and storage opportunities.
(2) Represents lower natural gas transportation and storage revenue as a result of a rate settlement between Dominion Transmission, Inc. (DTI) and its customers, effective July 1, 2005.
(3) Higher income resulting from the impact of favorable price changes related to price risk management and gas marketing activities associated with certain transportation and storage contracts.

2005 VS. 2004

(millions, except EPS)	Increase (Decrease) Amount	EPS
Producer services(1)	$ 119	$ 0.36
Economic hedges(2)	22	0.07
Cove Point(3)	13	0.04
Gas transmission rate settlement	(17)	(0.05)
Salaries, wages and benefits expense	(11)	(0.03)
Other	3	0.01
Share dilution		(0.04)
Change in net income contribution	$ 129	$ 0.36

(1) Reflects the impact of losses in the prior year related to certain energy trading activities that were exited in December 2004 and higher contributions from market-based gas trading, storage, transportation and aggregation activities.
(2) Represents the impact of price movements in 2004 associated with a portfolio of financial derivative instruments used to manage price risk associated with a portion of our anticipated sales of 2004 natural gas production that had not been considered in the hedging activities of the

Dominion E&P segment. In 2005, we did not enter into similar economic hedging transactions.
(3) Reflects the addition of a fifth storage tank in December 2004 and increased pipeline capacity.

Dominion Generation

Presented below are operating statistics related to Dominion Generation s operations:

Year Ended December 31,	2006	% Change	2005	% Change	2004
Electricity supplied (million mwhrs):					
Utility	79.7	(2)%	81.4	4%	78.0
Merchant[1]	41.7		41.5	43	29.1
Degree days (electric utility service area):					
Cooling	1,557	(9)	1,707	8	1,585
Heating	3,178	(16)	3,784	3	3,682

(1) Includes electricity supplied by the Peaker facilities whose results were reclassified to discontinued operations in December 2006 due to their pending sale.

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

2006 VS. 2005

(millions, except EPS)	Increase (Decrease) Amount	EPS
Merchant generation margin[1]	$ 215	$ 0.63
Unrecovered Virginia fuel expenses	40	0.12
Regulated electric sales:		
Customer growth	24	0.07
Weather	(64)	(0.18)
Other[2]	17	0.05
Sales of emissions allowances	(40)	(0.12)
Energy supply margin[3]	(27)	(0.08)
Outage costs[4]	(20)	(0.06)
Salaries, wages and benefits expense	(13)	(0.04)
2005 North Carolina rate case settlement	(10)	(0.03)
Other	(1)	
Share dilution		(0.03)
Change in net income contribution	$ 121	$ 0.33

(1) Primarily reflects higher realized prices.
(2) Primarily attributable to rate variations from changes in customer usage patterns and sales mix, and other factors.
(3) Primarily reflects a reduced benefit from FTRs in excess of congestion costs at our utility operations.
(4) Primarily due to an increase in the duration of scheduled outage days for our electric utility and certain merchant fossil plants.

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2005 VS. 2004

(millions, except EPS)	Increase (Decrease) Amount	EPS
Unrecovered Virginia fuel expenses	$ (280)	$ (0.85)
Energy marketing and risk management activities[1]	(50)	(0.15)
Interest and other financing expense[2]	(44)	(0.13)
Salaries, wages and benefits expense	(36)	(0.11)
Merchant generation margin[3]	102	0.31
Sales of emissions allowances	63	0.19
Energy supply margin[4]	40	0.12
Regulated electric sales:		
Weather	39	0.12
Customer growth	24	0.07
Purchased electric capacity expense	37	0.11
2005 North Carolina rate case settlement	10	0.03
Other	(22)	(0.07)
Share dilution		(0.05)
Change in net income contribution	$ (117)	$ (0.41)

(1) Reflects lower gains in 2005 from coal trading and marketing activities and losses related to price risk management activities and legacy power transactions.
(2) Represents higher interest rates on affiliate borrowings and variable rate debt, prepayment penalties resulting from the early redemption of debt and the lease financing of Fairless.
(3) Primarily represents contributions from Dominion New England and Kewaunee, partially offset by a lower contribution from the Millstone power station due to an additional scheduled outage in 2005.
(4) Higher energy supply margins reflect a benefit from FTRs in excess of congestion costs at our utility operations.

Dominion E&P

Presented below are operating statistics related to Dominion E&P s operations:

Year Ended December 31,	2006	% Change	2005	% Change	2004
Gas production (bcf)	308	10%	280	(17)%	337
Oil production (million bbls)	24.7	61	15.3	13	13.6
Average realized prices without hedging results:					
Gas (per mcf)[1]	$ 6.63	(17)	$ 7.98	39	$ 5.74
Oil (per bbl)	54.66	10	49.54	40	35.49
Average realized prices with hedging results[2]:					
Gas (per mcf)[1]	4.29	(9)	4.73	16	4.08
Oil (per bbl)	33.39	11	30.21	20	25.11
DD&A (per mcfe)	1.71	16	1.47	13	1.30
Average production (lifting) cost (per mcfe)[3]	1.19	2	1.17	27	0.92

bbl = barrel

mcf = thousand cubic feet

mcfe = thousand cubic feet equivalent

(1) Excludes $262 million, $323 million and $223 million of revenue recognized in 2006, 2005 and 2004, respectively, under the volumetric production payment (VPP) agreements described in Note 12 to our Consolidated Financial Statements.
(2) Excludes the effects of the economic hedges discussed under *Dominion Energy*.

(3) The inclusion of volumes produced and delivered under the VPP agreements would have resulted in lifting costs of $1.06, $1.00 and $0.83 for 2006, 2005 and 2004, respectively.

Presented below, on an after-tax basis, are the key factors impacting Dominion E&P s net income contribution:

2006 VS. 2005

(millions, except EPS)	Increase (Decrease) Amount	EPS
Gas and oil production[1]	$ 406	$ 1.18
Business interruption insurance	62	0.18
Operations and maintenance[2]	40	0.11
Gas and oil prices	(208)	(0.60)
DD&A	(162)	(0.47)
Interest expense[3]	(30)	(0.09)
Other	7	0.02
Share dilution		(0.04)
Change in net income contribution	$ 115	$ 0.29

(1) Represents an increase primarily in Gulf of Mexico deepwater and shelf gas and oil production and Rocky Mountain gas production.
(2) Primarily reflects the impact of mark-to-market gains associated with gas hedges that were de-designated following the 2005 hurricanes, partially offset by increased production costs and salaries, wages and benefits expense.
(3) Primarily reflects additional intercompany borrowings and higher interest rates on those borrowings.

2005 VS. 2004

(millions, except EPS)	Increase (Decrease) Amount	EPS
Operations and maintenance[1]	$ (134)	$ (0.41)
Gas and oil production[2]	(111)	(0.34)
Interest expense[3]	(25)	(0.08)
Gas and oil prices	185	0.56
Business interruption insurance Hurricane Ivan	50	0.15
Other	5	0.02
Share dilution		(0.06)
Change in net income contribution	$ (30)	$ (0.16)

(1) Reflects the absence of a 2004 benefit from favorable changes in the fair value of certain oil options, an increase in hedge ineffectiveness expense in 2005 and the discontinuance of hedge accounting for certain oil hedges in March 2005 largely resulting from delays in reaching anticipated production levels in the Gulf of Mexico, and subsequent changes in the fair value of those hedges, partially offset by a benefit reflecting the impact of a decrease in gas and oil prices on hedges that were de-designated following the 2005 hurricanes.
(2) Reflects interruptions caused by the 2005 hurricanes and the sale of the majority of our natural gas and oil properties in British Columbia, Canada in December 2004.
(3) Represents the combined impact of an increase in affiliate borrowings and higher interest rates, as well as prepayment penalties resulting from the early redemption of Canadian debt.

Included below are the volumes and weighted average prices associated with hedges in place as of December 31, 2006 by applicable time period:

Year	Natural Gas Hedged production	Natural Gas Average hedge price	Oil Hedged production	Oil Average hedge price

	(bcf)	(per mcf)	(million bbls)	(per bbl)
2007	**225.2**	**$ 5.90**	**10.0**	**$ 33.41**
2008	**174.9**	**8.23**	**5.0**	**49.36**
2009	**36.6**	**7.97**	**0.3**	**75.36**

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Corporate

Presented below are the Corporate segment s after-tax results:

(millions, except EPS amounts)	2006	2005	2004
Specific items attributable to operating segments	$ (149)	$ (505)	$ (224)
DCI operations	(95)	(22)	(82)
Peaker discontinued operations	(183)	(13)	(9)
Telecommunications operations(1)		5	(13)
Other corporate operations	(208)	(180)	(207)
Total net expense	(635)	(715)	(535)
Earnings per share impact	$ (1.80)	$ (2.07)	$ (1.61)

(1) $5 million and $(15) million are classified as discontinued operations in 2005 and 2004, respectively.

Specific Items Attributable to Operating Segments

Corporate includes 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. See Note 28 to our Consolidated Financial Statements for discussion of these items.

DCI Operations

DCI s net loss for 2006 increased $73 million, primarily due to an $85 million impairment of a DCI investment during the third quarter of 2006.

DCI recognized a net loss of $22 million in 2005; a decrease of $60 million as compared to 2004. The decrease primarily resulted from a reduction in after-tax charges associated with the impairment and divestiture of other DCI investments.

Peaker Discontinued Operations

In 2006, we recognized a $283 million ($183 million after-tax) loss from the discontinued operations of the Peaker facilities. The loss from discontinued operations includes:

- $253 million ($164 million after-tax) associated with the impairment of the merchant generation facilities; and
- $30 million ($19 million after-tax) of operating losses.

As a result of the pending sale, we reclassified 2005 and 2004 after-tax operating losses of $13 million and $9 million, respectively, to discontinued operations.

Telecommunications Operations

We sold our telecommunications business in May 2004 to Elantic Telecom, Inc., which subsequently filed for bankruptcy. Due to the resolution of certain contingencies, we recognized an after-tax benefit of $5 million in 2005 related to the discontinued telecommunications business.

Other Corporate Operations

The net expenses associated with other corporate operations for 2006 increased by $28 million as compared to 2005, primarily reflecting a $37 million after-tax charge to eliminate the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts.

The net expenses associated with other corporate operations for 2005 decreased by $27 million as compared to 2004, primarily reflecting an increase in interest income from affiliate advances and higher income tax benefits. This was partially offset by the

absence of a $28 million after-tax benefit in 2004 associated with the disposition of CNG International s investment in Australian pipeline assets.

SELECTED INFORMATION ENERGY TRADING ACTIVITIES

We engage in energy trading, marketing and hedging activities to complement our integrated energy businesses and facilitate our risk management activities. As part of these operations, we enter into contracts for purchases and sales of energy-related commodities, including natural gas, electricity, oil and coal. Settlements of contracts may require physical delivery of the underlying commodity or cash settlement. We also enter into contracts with the objective of benefiting from changes in prices. For example, after entering into a contract to purchase a commodity, we typically enter into a sales contract, or a combination of sales contracts, with quantities and delivery or settlement terms that are identical or very similar to those of the purchase contract. When the purchase and sales contracts are settled either by physical delivery of the underlying commodity or by net cash settlement, we may receive a net cash margin (a realized gain), or may pay a net cash margin (a realized loss). We continually monitor our contract positions, considering location and timing of delivery or settlement for each energy commodity in relation to market price activity.

A summary of the changes in the unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes during 2006 follows:

(millions)	Amount
Net unrealized loss at December 31, 2005	$ (7)
Contracts realized or otherwise settled during the period	(14)
Net unrealized gain at inception of contracts initiated during the period	
Change in unrealized gains and losses	63
Changes in unrealized gains and losses attributable to changes in valuation techniques	
Net unrealized gain at December 31, 2006	$ 42

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at December 31, 2006, is summarized in the following table based on the approach used to determine fair value:

	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)	$ 42	$ (2)	$ 1	$	$	$ 41
Other external sources(2)		1	(4)	3	1	1
Models and other valuation methods						
Total	$ 42	$ (1)	$ (3)	$ 3	$ 1	$ 42

(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.

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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 $3.0 billion of unused capacity under our credit facilities. See additional discussion under *Credit Facilities and Short-Term Debt*.

A summary of our cash flows for 2006, 2005 and 2004 is presented below:

(millions)	2006	2005	2004
Cash and cash equivalents at beginning of year	$ 146	$ 361	$ 126
Cash flows provided by (used in):			
Operating activities	4,005	2,623	2,770
Investing activities	(3,494)	(3,360)	(1,215)
Financing activities	(515)	522	(1,320)
Net increase (decrease) in cash and cash equivalents	(4)	(215)	235
Cash and cash equivalents at end of year[1]	$ 142	$ 146	$ 361

(1) 2006 amount includes $4 million of cash classified as held for sale in our Consolidated Balance Sheet.

Operating Cash Flows

In 2006, net cash provided by operating activities increased by $1.4 billion as compared to 2005. The increase was primarily due to an increase in cash earnings attributable to higher natural gas and oil production, recovery of deferred fuel and purchased gas costs and business interruption insurance proceeds, as well as increased contributions from our merchant generation, nonregulated retail energy marketing and gas transmission businesses. The 2006 increase also reflects favorable changes in working capital, mainly accounts receivable and inventories. We believe that our operations provide a stable source of cash flow sufficient to contribute to planned levels of capital expenditures and maintain or grow the dividend on common shares. 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. The declaration and payment of dividends are subject to the discretion of our Board of Directors and will depend upon our results of operations, financial condition, capital requirements and future prospects.

CREDIT RISK

Our exposure to potential concentrations of credit risk results primarily from our energy marketing and price risk management activities and sales of gas and oil production. Presented below is a summary of our gross credit 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.

(millions)	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
Investment grade[1]	$ 855	$ 28	$ 827
Non-investment grade[2]	57	2	55
No external ratings:			
Internally rated investment grade[3]	280	5	275
Internally rated non-investment grade[4]	171		171
Total	$ 1,363	$ 35	$ 1,328

(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 (Standard & Poor s). The five largest counterparty exposures, combined, for this category represented approximately 21% 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 13% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 3% of the total net credit exposure.

Investing Cash Flows

Significant cash flows used in investing activities for 2006 included:

- $2.1 billion of capital expenditures for the purchase and development of gas and oil producing properties, drilling and equipment costs and undeveloped lease acquisitions;
- $2.0 billion of capital expenditures, including environmental upgrades, routine capital improvements, construction of generation facilities, purchase of nuclear fuel and construction and improvements of gas and electric transmission and distribution assets;
- $1.1 billion for purchases of securities held as investments in our nuclear decommissioning trusts; and
- $91 million related to the acquisition of Pablo Energy LLC, which holds producing and other properties in the Texas Panhandle area, net of cash acquired.

Cash flows used in investing activities for 2006 were partially offset by:

- $1.0 billion of proceeds from the sales of securities held as investments in our nuclear decommissioning trusts;
- $393 million of proceeds from sales of gas and oil properties, primarily resulting from the fourth quarter sale of certain properties located in Texas and New Mexico;
- $150 million of proceeds received from the sale or disposal of certain assets; and
- $76 million of proceeds from sales of emissions allowances held for consumption.

Financing Cash Flows and Liquidity

We rely on banks and capital markets as significant sources of funding for capital requirements not satisfied by cash provided by the companies operations. As discussed in *Credit Ratings*, 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 certain regulatory approvals, including registration with the SEC and, in the case of Virginia Electric and Power Company (Virginia Power), approval by the Virginia State Corporation Commission (Virginia Commission).

In December 2005, the 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, Dominion and Virginia Power meet the definition of a well-known seasoned issuer. This allows the companies 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:

- $2.3 billion for the repayment of long-term debt;
- $970 million of common dividend payments;
- $540 million for the repurchase of common stock; and
- $300 million for the repayment of affiliated notes payable; partially offset by
- $2.5 billion from the issuance of long-term debt;
- $713 million from the net issuance of short-term debt; and
- $479 million from the issuance of common stock.

CREDIT FACILITIES AND SHORT-TERM DEBT

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 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. 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 our credit quality and the credit quality of our counterparties. Short-term financing is supported by a $3.0 billion five-year joint credit facility with Virginia Power and CNG dated February 2006, that can also be used to support up to $1.5 billion of letters of credit. Short-term financing at CNG is also supported by an amended and restated $1.7 billion five-year revolving credit facility and a $1.05 billion 364-day credit facility, both dated February 2006. At December 31, 2006, we had committed lines of credit totaling $5.75 billion. These lines of credit support commercial paper borrowings, bank loans and letter of credit issuances. Our financial policy precludes issuing commercial paper in excess of our supporting lines of credit. At December 31, 2006, we had the following commercial paper, bank loans and letters of credit outstanding and capacity available under credit facilities:

(millions)	Facility Limit	Outstanding Commercial Paper	Outstanding Bank Loans	Outstanding Letters of Credit	Facility Capacity Available
Five-year revolving joint credit facility[1]	$ 3,000	$ 1,759	$	$ 236	$ 1,005
Five-year CNG credit facility[2]	1,700		500	484	716
364-day CNG credit facility[3]	1,050				1,050
Totals	$ 5,750	$ 1,759	$ 500	$ 720	$ 2,771

(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 primarily used to support the issuance of letters of credit and commercial paper by CNG to fund collateral requirements under its gas and oil hedging program. The facility was entered into in February 2006 and terminates in August 2010. In October 2006, we borrowed $500 million from this facility to repay CNG s $500 million 2001 Series B 5.375% Senior Notes, which matured on November 1, 2006. We expect to repay the outstanding loan with proceeds received from pending asset sales.
(3) The $1.05 billion 364-day credit facility was used to support the issuance of letters of credit and commercial paper by CNG to fund collateral requirements under its gas and oil hedging program. The facility was entered into in February 2006 and terminated in February 2007.

We have also entered into several bilateral credit facilities in addition to the facilities above in order to provide collateral required on derivative contracts used in our risk management strategies for gas and oil production operations. At December 31, 2006, we had the following letter of credit facilities:

Company (millions)	Facility Limit	Outstanding Letters of Credit	Facility Capacity Remaining	Facility Inception Date	Facility Maturity Date
CNG	$ 100	$ 25	$ 75	June 2004	June 2007
CNG	100	100		August 2004	August 2009
CNG(1)	200		200	December 2005	December 2010
Totals	$ 400	$ 125	$ 275		

(1) This facility can also be used to support commercial paper borrowings.

In connection with our commodity hedging activities, we are required to provide collateral to counterparties under some circumstances. Under certain collateral arrangements, we may satisfy these requirements by electing to either deposit cash, post letters of credit or, in some cases, utilize other forms of security. From time to time, we vary the form of collateral provided to counterparties after weighing the costs and benefits of various factors associated with the different forms of collateral. These factors include short-term borrowing and short-term investment rates, the spread over these short-term rates at which we can issue commercial paper, balance sheet impacts, the costs and fees of alternative collateral postings with these and other counterparties and overall liquidity management objectives.

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LONG-TERM DEBT

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

Type	Principal (millions)	Rate	Maturity	Issuing Company
Enhanced junior subordinated notes	$ 500	6.30%	2066	Dominion
Senior notes	400	variable	2008	Dominion
Enhanced junior subordinated notes	300	7.50%	2066	Dominion
Senior notes	250	5.60%	2016	Dominion
Senior notes	550	6.00%	2036	Virginia Power
Senior notes	450	5.40%	2016	Virginia Power
Total long-term debt issued	$ 2,450			

In February 2006, we successfully remarketed $330 million of 5.75% 2002 Series A senior notes related to our equity-linked debt securities. The senior notes, which will mature in 2008, now carry an annual interest rate of 5.687%.

In February 2006, Dominion Energy Brayton Point, LLC borrowed $47 million in connection with the Massachusetts Development Finance Agency s issuance of its Solid Waste Disposal Revenue Bonds (Dominion Energy Brayton Point Issue) Series 2006, which mature in 2036 and bear a coupon rate of 5.0%. The bonds were issued pursuant to a trust agreement whereby funds are withdrawn from the trust as improvements are made at our Brayton Point Station located in Somerset, Massachusetts. We have withdrawn $33 million from the trust as of December 31, 2006.

In June 2006, DCI began consolidating a collateralized debt obligation (CDO) entity in accordance with FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R). At December 31, 2006, this CDO entity had $385 million of notes payable that mature in January 2017 and are nonrecourse to us.

During 2006, we repaid $2.3 billion of long-term debt securities.

ISSUANCE OF COMMON STOCK

During 2006, we issued 6.6 million shares of common stock and received proceeds of $479 million. Of this amount, 4.5 million shares and proceeds of $330 million resulted from the settlement of stock purchase contracts associated with our 2002 issuance of equity-linked debt securities. The remainder of the shares issued and proceeds received were through Dominion Direct® (a dividend reinvestment and open enrollment direct stock purchase plan), employee savings plans and the exercise of employee stock options. From May 2006 until November 2006, we issued new common shares in consideration of proceeds received through these programs. In November 2006, we began purchasing our

common stock on the open market with the proceeds received through these programs, rather than having additional new common shares issued.

REPURCHASES OF COMMON STOCK

In February 2005, we were authorized by our Board of Directors to repurchase up to the lesser of 25 million shares or $2.0 billion of our outstanding common stock.

Pursuant to this authority, in November 2006, we repurchased 500 thousand shares of our common stock for approximately $40 million. Additionally, in December 2006, we entered into a prepaid accelerated share repurchase agreement (ASR) with a financial institution as the counterparty. Under the ASR, we will ultimately receive between 5.6 million and 6.5 million shares in exchange for the prepayment of $500 million. At the time of execution of the ASR, the counterparty delivered to us 5 million shares. The final number of shares delivered to the Company will be determined by a volume weighted-average price of our common stock over the period commencing on December 12, 2006, and terminating on or before May 16, 2007. The actual termination date is at the option of the counterparty. The average price to be used to determine the final shares delivered to the Company is subject to a maximum and minimum price. Assuming normal termination, we will receive a minimum of 560 thousand additional shares. In no event will termination, normal or otherwise, result in the Company delivering shares or additional cash to the counterparty.

At December 31, 2006 the remaining purchase authorization is the lesser of 15.7 million shares or $1.2 billion of our outstanding common stock.

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 the current credit ratings of Dominion, Virginia Power and CNG (the Dominion Companies) provide sufficient access to the capital markets. However, disruptions in the banking and capital markets not specifically related to us may affect the Dominion Companies 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 an individual company s credit rating. Credit ratings should be evaluated independently and are subject to revision or withdrawal at any time by the assigning rating organization. The credit ratings for the Dominion Companies are most affected by each company s financial profile, mix of regulated and nonregulated businesses and respective cash flows, changes in methodologies used by the rating agencies and event risk, if applicable, such as major acquisitions or dispositions.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, CONTINUED

Credit ratings for the Dominion Companies as of February 1, 2007 follow:

	Fitch	Moody s	Standard & Poor s
Dominion Resources, Inc.			
Senior unsecured debt securities	BBB+	Baa2	BBB
Junior subordinated debt securities	BBB	Baa3	BB+
Enhanced junior subordinated notes	BBB	Baa3	BB+
Commercial paper	F2	P-2	A-2
Virginia Power			
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
CNG			
Senior unsecured debt securities	BBB+	Baa1	BBB
Junior subordinated debt securities	BBB	Baa2	BB+
Commercial paper	F2	P-2	A-2

In November 2006, Standard & Poor s placed the credit ratings for the Dominion Companies on positive outlook, citing that the sale of the oil and gas assets would be favorable as it improves Dominion s business risk profile by significantly reducing exposure to this segment to less than 5% of overall cash flow. Moody s reaffirmed its credit ratings for the Dominion Companies, stating that the oil and gas divestiture is a potentially positive development for the credit, but will not have a material effect on the ratings at this time. Moody s stated that a divestiture of Dominion s oil and gas operations will substantially reduce the nonregulated revenues, earnings, cash flows and assets as a percentage of the consolidated company, which will, in turn, significantly lower our overall business and operating risk profile. Fitch reaffirmed its credit ratings for the Dominion Companies, stating that the closing of the potential oil and gas sale would alleviate several of Fitch s primary rating concerns and increase the share of consolidated cash flows from more stable businesses.

Generally, a downgrade in an individual company s credit rating would not restrict its ability to raise short-term and long-term financing as long as its 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 and earnings per share.

Debt Covenants

As part of borrowing funds and issuing debt (both short-term and long-term) or preferred securities, the Dominion Companies 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, including dividends, redemptions, repurchases, liquidation payments or guarantee payments; and in some cases, the termination of credit commitments unless a waiver of such requirements is agreed to by the lenders/security holders. These provisions are customary, with each agreement specifying which covenants apply. These provisions are not necessarily unique to the Dominion Companies.

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 our credit facilities. In addition, our credit agreements contain various terms and conditions that could affect our ability to borrow under these facilities. They include maximum debt to total capital ratios and cross-default provisions.

As of December 31, 2006, the calculated total debt to total capital ratio for our companies, pursuant to the terms of the agreements, was as follows:

Company	Maximum Ratio	Actual Ratio(1)
Dominion Resources, Inc.	65%	54%
Virginia Power	65%	47%
CNG	65%	47%

(1) Indebtedness as defined by the bank agreements excludes junior subordinated notes payable reflected as long-term debt on our Consolidated Balance Sheets.

These provisions apply separately to the Dominion Companies. If any one of the Dominion Companies or any of that specific company s material subsidiaries fail to make payment on various debt obligations in excess of $35 million, the lenders could require that respective company to accelerate its repayment of any outstanding borrowings under the credit facility and the lenders could terminate their commitment to lend funds to that company. Accordingly, any defaults on indebtedness by CNG or any of its material subsidiaries would not affect the lenders commitment to Virginia Power. Similarly, any defaults on indebtedness by Virginia Power or any of its material subsidiaries would not affect the lenders commitment to CNG. Likewise, any default by Dominion will not affect the lender s commitment to Virginia Power or CNG. However, any default by either CNG or Virginia Power would also affect in like manner the lenders commitment to Dominion under the joint credit agreement.

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 have initially designated the $250 million 8.4% Capital Securities of Dominion Resources Capital Trust III that were issued in January 2001 as covered debt under the RCCs. In the future, we will be allowed to change the series of our debt designated as covered debt under the RCCs. Under the terms of the RCCs, we agree not to redeem or repurchase all or part of the June or September hybrids prior to June 30 or September 30, 2036, respectively, unless we issue qualifying securities to non-affiliates in a replacement offering in the 180 days prior to

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the redemption or repurchase date. The proceeds we receive from the replacement offering, adjusted by a predetermined factor, must exceed the redemption or repurchase price. Qualifying securities include common stock, preferred stock and other securities that generally rank equal to or junior to the hybrids and include distribution deferral and long-dated maturity features similar to the hybrids. For purposes of the RCCs, non-affiliates include individuals enrolled in our dividend reinvestment plan, direct stock purchase plan and employee benefit plans.

We monitor the covenants on a regular basis in order to ensure that events of default will not occur. Other than the RCCs discussed above, as of December 31, 2006, there have been no changes to or events of default under our debt covenant.

Dividend Restrictions

The Virginia Commission may prohibit any public service company, including Virginia Power, 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 the payment of dividends by Virginia Power.

Certain agreements associated with our credit facilities contain restrictions on the ratio of our debt to total capitalization. These limitations did not restrict our ability to pay dividends or receive dividends from our subsidiaries at December 31, 2006.

See Note 18 to our Consolidated Financial Statements for a description of potential restrictions on dividend payments by us and certain of our subsidiaries in connection with the deferral of distribution payments on trust preferred securities or deferral of interest payments on enhanced junior subordinated notes.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

We are party to numerous contracts and arrangements obligating the Company 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 and financial derivatives. 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 certain derivative instruments. The majority of our current liabilities will be paid in cash in 2007.

(millions)	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Long-term debt[1]	$ 2,479	$ 2,021	$ 2,443	$ 10,370	$ 17,313
Interest payments[2]	1,005	1,662	1,378	9,904	13,949
Leases	209	345	250	294	1,098
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
Fuel to be used for nonregulated operations	28	68	58	172	326
Production handling	54	69	26	5	154
Pipeline transportation and storage	149	241	121	85	596
Energy commodity purchases for resale[4]	469	31	12	4	516
Other[5]	594	166	49	68	877
Other long-term liabilities[6]:					
Financial derivative commodities[4]	839	189	2		1,030
Other contractual obligations[7]	60	84	15		159
Total cash payments	$ 7,017	$ 6,459	$ 5,418	$ 23,682	$ 42,576

(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 and enhanced junior subordinated notes.
(3) Amounts exclude open purchase orders for services that are provided on demand, the timing of which cannot be determined.
(4) Represents the summation of settlement amounts, by contracts, due from us if all physical or financial transactions among our counterparties and the Company were liquidated and terminated.
(5) Includes capital and operations and maintenance commitments, onshore and offshore drilling rigs and funding for our investment in a wind-power facility as discussed in Note 23 to our Consolidated Financial Statements.
(6) Excludes regulatory liabilities, AROs and employee benefit plan obligations that are not contractually fixed as to timing and amount. See Notes 14, 15 and 22 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.
(7) Includes interest rate swap agreements.

Our planned capital expenditures during 2007 and 2008 are expected to total approximately $4.4 billion and $4.6 billion, respectively. These expenditures are expected to include construction and expansion of electric generation and LNG facilities, environmental upgrades, construction improvements and expansion of gas and electric transmission and distribution assets, purchases of nuclear fuel and expenditures to explore for and develop natural gas and oil properties. We expect to fund our capital expenditures with cash from operations and a combination of securities issuances and short-term borrowings.

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 Mw (at net summer capability) coal burning plant located in Hopewell, Virginia, which has been out of service since 2003, 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.

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

Use of Off-Balance Sheet Arrangements

GUARANTEES

We primarily enter into guarantee arrangements on behalf of our consolidated subsidiaries. These arrangements are not subject to the recognition and measurement provisions of FASB Interpretation No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* See Note 23 to our Consolidated Financial Statements for further discussion of these guarantees.

At December 31, 2006, we have issued $32 million of guarantees to support third parties, equity method investees and employees affected by Hurricane Katrina. In addition, in 2005, we, along with two other gas and oil E&P companies, entered into a four-year drilling contract related to a new, ultra-deepwater drilling rig that is expected to be delivered in mid-2008. The contract has a four-year primary term, plus four one-year extension options. Our minimum commitment under the agreement is for approximately $99 million over the four-year term; however, we are jointly and severally liable for up to $394 million to the contractor if the other parties fail to pay the contractor for their obligations under the primary term of the agreement. We believe this scenario is improbable and have not recognized any significant liabilities related to any of these arrangements.

In 2006, we, along with three other gas and oil exploration companies, executed agreements with a third party to design, construct, install and own the Thunder Hawk facility, a semi-submersible production facility to be located in the deepwater Gulf of Mexico. We anticipate that mechanical completion of the Thunder Hawk facility will occur in 2009 and that the processing of our production will start by 2010. Due to current offshore insurance market conditions, it is anticipated that the Thunder Hawk facility will only be partially insured against a catastrophic full or partial loss. We, along with the three other participating producers, will be required to continue to make demand payments in the event of a catastrophic loss if insurance payments are not sufficient to pay the lessor s outstanding debt incurred for the Thunder Hawk facility. The agreements require that we pay a demand charge of approximately $63 million over five years starting on the day after the mechanical completion of the Thunder

Hawk facility. Our obligation will terminate upon the earlier event of full payment of the lessor s debt incurred for the Thunder Hawk facility or the full payment of our demand charge obligation. We believe that it is unlikely that we would be required to perform under this guarantee and have not recognized any significant liabilities for this arrangement. The agreements also require the payment of production processing fees including a minimum processing fee if yearly production processing fees are below specified amounts. Our maximum obligation for the minimum processing fee would be approximately $3 million per year. Our obligation for the payment of these processing fees will terminate upon the cessation of our production.

LEASING ARRANGEMENT

We have an agreement to lease the Fairless power station in Pennsylvania, which began commercial operations in June 2004. During construction, we acted as the construction agent for the lessor, controlled the design and construction of the facility and have since been reimbursed for all project costs ($898 million) advanced to the lessor. We make annual lease payments of $53 million. The lease expires in 2013 and at that time, we may renew the lease at negotiated amounts based on original project costs and current market conditions, subject to lessor approval; purchase Fairless at its original construction cost; or sell Fairless, on behalf of the lessor, to an independent third party. If Fairless is sold and the proceeds from the sale are less than its original construction cost, we would be required to make a payment to the lessor in an amount up to 70.75% of original project costs adjusted for certain other costs as specified in the lease. The lease agreement does not contain any provisions that involve credit rating or stock price trigger events.

Benefits of this arrangement include:

- Certain tax benefits as we are considered the owner of the leased property for tax purposes. As a result, we are entitled to tax deductions for depreciation not recognized for financial accounting purposes; and
- As an operating lease for financial accounting purposes, the asset and related borrowings used to finance the construction of the asset are not included in our Consolidated Balance Sheets. Although this improves measures of leverage calculated using amounts reported in our Consolidated Financial Statements, credit rating agencies view lease obligations as debt equivalents in evaluating our credit profile.

FUTURE ISSUES AND OTHER MATTERS

Status of Electric Restructuring in Virginia

1999 VIRGINIA RESTRUCTURING ACT

The Virginia Electric Utility Restructuring Act (1999 Virginia Restructuring Act) was enacted in 1999 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 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.

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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 Commission 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 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;

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  - 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; or
  - 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.

Transmission Expansion Plan

Each year, as part of PJM s Regional Transmission Expansion Plan (RTEP) process, reliability projects will be 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.

Offshore Oil and Gas Leases

A bill passed by the U.S. House of Representatives on January 16, 2007, but not yet enacted into law, addresses certain federal offshore oil and gas leases issued in 1998 and 1999 that do not include a provision requiring royalties to be paid on specified royalty suspension volumes when oil and gas commodity futures closing prices exceed specified threshold levels (as is the case under current market conditions). The bill imposes a conservation of resources fee of $1.25 per million British thermal units (MMbtu) of gas and $9.00 per barrel oil (2005 dollars) produced from such leases on and after October 1, 2006 in calendar years when the average oil or gas (as applicable) commodity futures monthly closing prices on the New York Mercantile Exchange (NYMEX) exceed $4.34 per MMbtu for gas or $34.73 for oil (2005 dollars). In addition, commencing on and after October 1, 2006, in calendar years when the average NYMEX monthly closing prices exceed the foregoing thresholds, a conservation of resources fee of $3.75 per acre per lease per year is imposed on such leases that are non-producing. The bill permits lessees to avoid payment of the foregoing fee by agreeing to lease amendments that provide that royalties are payable with respect to royalty suspension volumes on and after October 1, 2006 when the foregoing threshold conditions are met. Finally, the bill imposes sanctions on lessees, including disqualification from future offshore lease sales, for those who do not enter into such lease amendments and fail to pay the fee. The Senate is considering similar legislation.

Common Stock Dividend Increase

In January 2007, our quarterly dividend rate increased from 69 cents per share to 71 cents per share, for an annual rate in 2007 of $2.84. While all dividends are payable only as and when declared by the Board of Directors, our expected cash flow and earnings should enable us to pay dividends at the current rate and to make future increases when our Board of Directors deems it financially prudent. The Board of Directors declares common stock dividends on a quarterly basis.

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. We also may seek recovery through regulated rates for environmental expenditures related to regulated gas 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.

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ENVIRONMENTAL PROTECTION AND MONITORING EXPENDITURES

We incurred approximately $138 million, $205 million and $132 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 $181 million and $188 million in 2007 and 2008, respectively. In addition, capital expenditures related to environmental controls were $332 million, $140 million and $94 million for 2006, 2005 and 2004, respectively. These expenditures are expected to be approximately $300 million and $174 million for 2007 and 2008, respectively.

CLEAN AIR ACT (CAA) 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 (NO_X) and mercury emissions from electric generating facilities. The SO_2 and NO_X emission reduction requirements are imposed in two phases, with initial reduction levels targeted for 2009 (NO_X) and 2010 (SO_2), and a second phase of reductions targeted for 2015 (SO_2 and NO_X). 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. West Virginia has adopted both final rules. Illinois has adopted CAMR and is more strict than the federal requirements. 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. Illinois has proposed, but not yet finalized, regulations to implement CAIR, which are also more strict than the federal requirements. Separate from CAIR and CAMR, Massachusetts has regulations specifically targeting reductions in NO_x, SO_2, carbon dioxide (CO_2) and mercury emissions from our affected facilities in Massachusetts. These CAA 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). The 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 at this time. Implementation of projects to comply with these SO_2, NO_X and mercury limitations, and other state emission control programs are ongoing and will be influenced by changes in the regulatory environment, availability of emission allowances and emission control technology. In response to these CAA requirements, we estimate that we will

make capital expenditures at our affected generating facilities of approximately $958 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 thirteen states, claiming emissions from those units are contributing to air quality problems in North Carolina. We have electrical generating units in six 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 CAIR adequately addresses the air quality issues identified by North Carolina. Therefore, we do not anticipate additional expenditures in relation to this matter.

OTHER

We operate two fossil fuel-fired generating power stations in Massachusetts that are subject to the implementation of CO_2 emission regulations issued by the Massachusetts Department of Environmental Protection. The final CO_2 regulations have been promulgated and contain provisions that limit our liability through the establishment of alternative compliance payments. Based on our analysis we estimated that the impact of these regulations will not be material.

Additionally, in January 2007, the Governor of Massachusetts signed the Regional Greenhouse Gas Initiative, committing Massachusetts to a multi-state effort to reduce emissions of carbon dioxide. Implementing regulations in Massachusetts have yet to be promulgated. Until the implementing regulations are promulgated, it is not possible to predict the financial impact that may result.

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 $8 million over the next 2 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.

In August 2006, the Connecticut Department of Environmental Protection (CTDEP) issued a notice of a Tentative Determination to renew Millstone Power Station s pollution elimination discharge permit, which included a draft copy of the revised permit. An administrative hearing will be held on the draft permit with a Final Determination expected to be issued by the CTDEP within the next year. Until the final permit is reissued, it is not possible to predict the financial impact that may result.

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. 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 Envi -

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ronmental 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. Both permits are stayed pending the outcome of the EPA process. Until the remand process and any resulting appeals are completed, the outcome of this matter cannot be predicted.

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 to include provisions seeking to target the reductions of greenhouse gas emissions. In addition to possible federal action, some of the states in which we operate have already or may adopt carbon reduction programs. 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 and states 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 of Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations. 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 present in our electric operations, gas and oil production and procurement operations, and energy marketing and trading operations due to the exposure to market

shifts in prices received and paid for natural gas, oil, electricity and other commodities. We use commodity derivative contracts to manage price risk exposures for these operations. 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

We manage price risk associated with purchases and sales of natural gas, oil, electricity 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 $597 million and $691 million as of December 31, 2006 and 2005, respectively. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $3 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of December 31, 2006 and 2005, 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

Our Canadian natural gas and oil E&P activities are relatively self-contained within Canada. As a result, our exposure to foreign currency exchange risk for these activities is limited primarily to the effects of translation adjustments that arise from including that operation in our Consolidated Financial Statements. We monitor this exposure and believe it is not material. In addition, 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%

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unfavorable change in relevant foreign exchange rates would have resulted in a decrease of approximately $3 million and $8 million in the fair value of currency forward contracts held 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, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $25 million. A hypothetical 10% increase in market interest rates, as determined at December 31, 2005, would have resulted in a decrease in annual earnings of approximately $20 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 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 $63 million and $67 million in 2006 and 2005, respectively. We recorded, in AOCI, gross unrealized gains on these investments of $194 million in 2006 and net unrealized gains of $27 million in 2005.

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. Our pension and other postretirement benefit plans experienced net realized and unrealized gains of $674 million and $484 million in 2006 and 2005, respectively. As of December 31, 2006, a hypothetical 0.25% decrease in the assumed rates of return on our plan assets would result in an increase in net periodic cost of approximately $11 million for pension benefits and $2 million for other postretirement benefits. As of December 31, 2005, a hypothetical 0.25% decrease in the assumed rates of return on our plan assets would have resulted in an increase in net periodic cost of approximately $10 million for pension benefits and $2 million for other postretirement benefits.

Risk Management Policies

We have established operating procedures with corporate management to ensure that proper internal controls are maintained. In addition, we have established an independent function at the corporate level to monitor compliance with the risk management policies of all subsidiaries. We maintain 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, we also monitor the financial condition of existing counterparties on an ongoing basis. Based on our credit policies and the 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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Dominion Resources, Inc.

Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Dominion Resources, Inc. and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of income, common shareholders 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Dominion Resources, Inc. 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 methods of accounting to adopt new accounting standards for pension and other postretirement benefit plans, share-based payments, and purchases and sales of inventory with the same counterparty in 2006, and for conditional asset retirement obligations in 2005.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2007, expresses an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Richmond, Virginia

February 28, 2007

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CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31, (millions, except per share amounts)	2006	2005	2004
Operating Revenue	$ 16,482	$ 17,971	$ 13,929
Operating Expenses			
Electric fuel and energy purchases	3,236	4,670	2,126
Purchased electric capacity	481	504	587
Purchased gas	2,937	3,941	2,927
Other energy-related commodity purchases	1,022	1,391	989
Other operations and maintenance	3,280	3,054	2,755
Depreciation, depletion and amortization	1,606	1,397	1,289
Other taxes	575	581	519
Total operating expenses	13,137	15,538	11,192
Income from operations	3,345	2,433	2,737
Other income	174	168	167
Interest and related charges:			
Interest expense	890	844	798
Interest expense junior subordinated notes payable[1]	124	106	112
Subsidiary preferred dividends	16	16	16
Total interest and related charges	1,030	966	926
Income from continuing operations before income tax expense	2,489	1,635	1,978
Income tax expense	920	588	705
Minority interest	6		
Income from continuing operations before cumulative effect of change in accounting principle	1,563	1,047	1,273
Loss from discontinued operations (net of income tax benefit of $100, $2 and $10 in 2006, 2005 and 2004, respectively)	(183)	(8)	(24)
Cumulative effect of change in accounting principle (net of income tax benefit of $4)		(6)	
Net Income	$ 1,380	$ 1,033	$ 1,249
Earnings Per Common Share Basic:			
Income from continuing operations before cumulative effect of change in accounting principle	$ 4.47	$ 3.06	$ 3.87
Loss from discontinued operations	(0.52)	(0.02)	(0.07)
Cumulative effect of change in accounting principle		(0.02)	
Net income	$ 3.95	$ 3.02	$ 3.80
Earnings Per Common Share Diluted:			
Income from continuing operations before cumulative effect of change in accounting principle	$ 4.45	$ 3.04	$ 3.85
Loss from discontinued operations	(0.52)	(0.02)	(0.07)
Cumulative effect of change in accounting principle		(0.02)	
Net income	$ 3.93	$ 3.00	$ 3.78
Dividends paid per common share	$ 2.76	$ 2.68	$ 2.60

(1) Includes $104 million, $106 million and $112 million payable to affiliated trusts at December 31, 2006, 2005 and 2004, respectively.
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	$ 138	$ 146
Customer receivables (less allowance for doubtful accounts of $26 and $38)	2,395	3,335
Other receivables (less allowance for doubtful accounts of $13 and $9)	358	226
Inventories:		
Materials and supplies	429	392
Fossil fuel	383	314
Gas stored	289	461
Derivative assets	1,593	3,429
Assets held for sale	1,391	4
Deferred income taxes	310	928
Prepayments	254	161
Other	558	733
Total current assets	8,098	10,129
Investments		
Nuclear decommissioning trust funds	2,791	2,534
Available-for-sale securities	39	287
Loans receivable, net	399	31
Other	596	649
Total investments	3,825	3,501
Property, Plant and Equipment		
Property, plant and equipment	43,575	42,063
Accumulated depreciation, depletion and amortization	(14,193)	(13,123)
Total property, plant and equipment, net	29,382	28,940
Deferred Charges and Other Assets		
Goodwill	4,298	4,298
Pension and other postretirement benefit assets	1,246	1,915
Derivative assets	642	1,915
Intangible assets	628	619
Regulatory assets	539	758
Other	611	585
Total deferred charges and other assets	7,964	10,090
Total assets	$ 49,269	$ 52,660

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At December 31, (millions)	2006	2005
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Securities due within one year	$ 2,478	$ 2,330
Short-term debt	2,332	1,618
Accounts payable	2,142	2,756
Accrued interest, payroll and taxes	759	694
Derivative liabilities	2,276	6,087
Liabilities held for sale	497	
Other	745	995
Total current liabilities	11,229	14,480
Long-Term Debt		
Long-term debt	12,842	13,237
Junior subordinated notes payable to:		
Affiliates	1,151	1,416
Other	798	
Total long-term debt	14,791	14,653
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	5,858	4,984
Asset retirement obligations	1,930	2,249
Derivative liabilities	681	3,971
Regulatory liabilities	614	607
Other	973	1,062
Total deferred credits and other liabilities	10,056	12,873
Total liabilities	36,076	42,006
Commitments and Contingencies (see Note 23)		
Minority Interest	23	
Subsidiary Preferred Stock Not Subject To Mandatory Redemption	257	257
Common Shareholders Equity		
Common stock no par[1]	11,250	11,286
Other paid-in capital	128	125
Retained earnings	1,960	1,550
Accumulated other comprehensive loss	(425)	(2,564)
Total common shareholders equity	12,913	10,397
Total liabilities and shareholders equity	$ 49,269	$ 52,660

(1) 500 million shares authorized; 349 million shares and 347 million shares outstanding at December 31, 2006 and December 31, 2005, respectively.

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

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CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS EQUITY AND COMPREHENSIVE INCOME

	Common Stock					
(millions)	Shares	Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2003	325	$ 10,052	$ 61	$ 1,054	$ (629)	$ 10,538
Comprehensive income:						
Net income				1,249		1,249
Net deferred derivative losses hedging activities, net of $632 tax benefit					(1,118)	(1,118)
Net unrealized gains on investment securities, net of $18 tax expense					37	37
Foreign currency translation adjustments					30	30
Amounts reclassified to net income:						
Net realized losses on investment securities, net of $12 tax benefit					23	23
Net derivative losses hedging activities, net of $407 tax benefit					705	705
Foreign currency translation adjustments					(44)	(44)
Total comprehensive income				1,249	(367)	882
Issuance of stock equity-linked securities	7	413				413
Issuance of stock employee and direct stock purchase plans	3	206				206
Stock awards and stock options exercised (net of change in unearned compensation)	5	223				223
Cash settlement forward equity transaction		(6)				(6)
Tax benefit from stock awards and stock options exercised			31			31
Dividends				(861)		(861)
Balance at December 31, 2004	340	10,888	92	1,442	(996)	11,426
Comprehensive income:						
Net income				1,033		1,033
Net deferred derivative losses hedging activities, net of $1,648 tax benefit					(2,846)	(2,846)
Net unrealized gains on investment securities, net of $19 tax expense					27	27
Minimum pension liability adjustment, net of $3 tax expense					4	4
Foreign currency translation adjustments					10	10
Amounts reclassified to net income:						
Net realized gains on investment securities, net of $8 tax expense					(11)	(11)
Net derivative losses hedging activities, net of $723 tax benefit					1,250	1,250
Foreign currency translation adjustments					(2)	(2)
Total comprehensive income				1,033	(1,568)	(535)
Issuance of stock employee and direct stock purchase plans		9				9
Stock awards and stock options exercised (net of change in unearned compensation)	6	363				363
Issuance of stock forward equity transaction	5	319				319
Stock repurchase and retirement	(4)	(276)				(276)
Cash settlement forward equity transaction		(17)				(17)
Tax benefit from stock awards and stock options exercised			31			31
Dividends and other adjustments			2	(925)		(923)
Balance at December 31, 2005	347	11,286	125	1,550	(2,564)	10,397
Comprehensive income:						
Net income				**1,380**		**1,380**
Net deferred derivative gains hedging activities, net of $625 tax expense					**1,173**	**1,173**
Unrealized gains on investment securities, net of $83 tax expense					**126**	**126**
Minimum pension liability adjustment, net of $7 tax expense					**10**	**10**
Foreign currency translation adjustments					**(8)**	**(8)**
Amounts reclassified to net income:						

Net realized gains on investment securities, net of $6 tax expense					(9)	(9)
Net derivative losses hedging activities, net of $724 tax benefit					1,182	1,182
Total comprehensive income				1,380	2,474	3,854
Issuance of stock employee and direct stock purchase plans	1	95				95
Stock awards and stock options exercised (net of change in unearned compensation)	2	79				79
Issuance of stock equity-linked securities	4	330				330
Stock repurchase and retirement	(5)	(540)				(540)
Tax benefit from stock awards and stock options exercised			8			8
Adjustment to initially adopt SFAS No. 158, net of $239 tax benefit					(335)	(335)
Dividends and other adjustments			(5)	(970)		(975)
Balance at December 31, 2006	349	$ 11,250	$ 128	$ 1,960	$ (425)	$