DOMINION RESOURCES INC /VA/
Form 10-K
March 02, 2006
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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, 2005

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	**54-1229715**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
120 Tredegar Street	
Richmond, Virginia	**23219**
(Address of principal executive offices)	**(Zip Code)**

(804) 819-2000

(Registrant s telephone number)

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

Title of Each Class	**Name of Each Exchange on Which Registered**
Common stock, no par value	New York Stock Exchange
8.75% Equity income securities, $50 par	New York Stock Exchange
8.4% Trust preferred securities, $25 par	New York Stock Exchange

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

None

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 $24.6 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, 2006, Dominion had 347,479,911 shares of common stock outstanding.

DOCUMENT INCORPORATED BY REFERENCE.

(a) Portions of the 2006 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. This area, which stretches from Wisconsin, Illinois and adjoining states through our primary Mid-Atlantic service areas in Ohio, Pennsylvania, West Virginia, Virginia and North Carolina, and up through New York and New England, is home to approximately 40% of the nation s demand for energy.

The terms Dominion, Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Dominion Resources, Inc., one of Dominion Resources, Inc. s consolidated subsidiaries or operating segments or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries.

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 risk management activities and natural gas and oil exploration and production. VPEM provides fuel and risk management services to Virginia Power and other Dominion affiliates and engages in energy trading activities. VPEM was formerly an indirect wholly-owned subsidiary of Virginia Power, however on December 31, 2005, Virginia Power transferred VPEM to Dominion through a series of dividend distributions.

As of December 31, 2005, we had approximately 17,400 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.

Operating Segments

We manage our operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion Exploration & Production. We also report Corporate and other functions as a segment. While we manage our daily operations through 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 business, 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.

Competition

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

Deregulation is at varying stages 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, legislation has not been enacted to require supplier choice for residential and commercial natural gas consumers. However, we offer an Energy Choice program to customers on our own initiative, 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 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 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 54,000 miles of distribution lines, exclusive of service level lines, in Virginia and North Carolina. The right-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.

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Dominion Delivery s investment in its gas distribution network is located in the states of Ohio, Pennsylvania and West Virginia. Our gas distribution network involves approximately 27,000 miles of pipe, exclusive of service pipe. Dominion Delivery also operates more than 200 billion cubic feet (bcf) of gas storage in Ohio and Pennsylvania. See *Dominion Energy Properties* for additional information regarding Dominion Delivery s storage properties.

Sources of Fuel Supply

Dominion Delivery s supply of electricity to serve its retail customers is primarily provided 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: 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 us or third parties.

Seasonality

Dominion Delivery s business typically varies seasonally based on demand for electricity by residential and commercial customers for cooling and heating use based on changes in temperature. The same is true for gas sales based on heating needs.

Dominion Energy

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

Competition

Now that our electric transmission facilities have been integrated into PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), our electric transmission business is 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 and gas marketers seeking to provide or arrange transportation, storage and other services for customers. 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 longline 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 operations are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Virginia Commission and the North Carolina Commission. FERC also regulates our natural gas pipeline transmission, storage and LNG operations. 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, surplus capacity in the line, if any exists.

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.

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. We also have storage operations involving both Dominion Energy and Dominion Delivery. These storage operations include 26 underground gas storage fields located in New York, Ohio, Pennsylvania and West Virginia, with more than 2,000 storage wells and approximately 373,000 acres of operated leaseholds.

The total designed capacity of the underground storage fields is approximately 970 bcf of which approximately 200 bcf is operated by Dominion Delivery and 750 bcf is operated by Dominion Energy, with the remaining portion being operated by a third party. Six of the 26 storage fields are jointly-owned with other companies and have a capacity of 242 bcf. Dominion Energy also has approximately 8 bcf of above ground storage capacity at its Cove Point LNG facility. The Dominion Energy and Dominion Delivery segments together have more than 100 compressor stations with approximately 688,000 installed compressor horsepower.

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The map below illustrates our 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 gas pipelines and large markets in the Northeast and Mid-Atlantic regions. Our pipelines are part of an interconnected gas transmission system, which continues to provide local distribution companies, marketers, power generators and industrial and commercial customers accessibility to supplies nationwide.

Our underground storage facilities play an important part in balancing gas supply with consumer demand and are essential to serving the Midwest, Mid-Atlantic and Northeast 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 business is affected by seasonal changes in the prices of commodities that it transports and actively markets and trades.

Dominion Generation

Dominion Generation s electric utility and merchant fleet includes approximately 28,100 megawatts (Mw) of generation capability. The generation mix is diversified and includes coal, nuclear, gas, oil, hydro and purchased power. Our strategy for our electric generation operations focuses on serving customers in the energy intensive Northeast, Mid-Atlantic and Midwest regions of the United States.

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 risk management activities associated with the optimization of generation assets.

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 the extent originally anticipated. 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.

The majority of 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

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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, management believes that we have the expertise in operations, dispatch and risk management to maximize the degree to which our merchant fleet is competitive compared to like assets within the region.

Regulation

In Virginia and North Carolina, our electric utility generation facilities, along with power purchases, are used to serve our utility service area obligations. Due to amendments to the Virginia Restructuring Act and the fuel factor statute in 2004, revenues for serving Virginia jurisdictional retail load are based on capped base rates through 2010 and the related fuel costs for the generating fleet, including power purchases, are subject to fixed rate recovery provisions until July 1, 2007, when a one-time adjustment will be made effective through December, 2010. Such adjustment will be prospective and will not take into account any over-recovery or under-recovery of prior fuel costs. Subject to market conditions, any generation remaining after meeting utility system needs is sold into PJM.

Properties

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

Sources of Fuel Supply

Dominion Generation uses a variety of fuels to power its 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. 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 spot purchases. Additional utility requirements are purchased mainly under 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 us or third parties.

We have a portfolio of firm natural gas transportation contracts (capacity) that allow flexible natural gas deliveries 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.

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 is a nonregulated merchant plant with two operating units. A third Millstone unit ceased operations before we acquired the plant. In July 2005, we completed the acquisition of the 556-megawatt Kewaunee nuclear power station in eastern Wisconsin.

Decommissioning represents the decontamination and removal of radioactive contaminants from a nuclear power plant once operations have ceased, in accordance with standards established by the Nuclear Regulatory Commission (NRC). Amounts collected from ratepayers and placed in trusts have been invested to fund future costs of decommissioning the Surry and North Anna units. As part of our acquisition of both Millstone and Kewaunee, we acquired the decommissioning funds for the related units. Currently, we believe that the amounts 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 $3.5 billion and is primarily based upon site-specific studies completed in 2002. We will perform new cost studies 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 decommissioning activities begin for the remaining Millstone units. The current operating licenses expire in the years detailed in the following table. During 2005, the NRC approved Dominion s application for a 20-year life extension for Millstone Units 2 and 3. We expect to decommission the Surry and North Anna units during the period 2032 to 2045. We expect to start minor decommissioning activities at Millstone Unit 2 in 2034, with full decommissioning to take place at Millstone Units 2 and 3 during the period 2045 to 2057. We plan to file an application for a 20-year life extension for our Kewaunee unit. If the NRC approves the application, we currently expect to decommission Kewaunee during the period 2032 to 2042.

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	Surry		North Anna		Millstone			Kewaunee	
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2	Unit 3	Unit 1	Total
(millions)									
NRC license expiration year	2032	2033	2038	2040	(1)	2035	2045	2013	
Most recent cost estimate	$375	$368	$391	$363	$531	$486	$518	$440	$3,472
Funds in trusts at December 31, 2005	326	321	266	252	285	327	322	434	2,533
2005 contributions to trusts	1.5	1.7	1.1	1.1					5.4

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

Dominion Exploration & Production (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, and Western Canada.

Competition

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

In terms of its production activities, 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 production 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 exploration and production operations are subject to regulation by numerous federal and state authorities. The pipeline transportation of our natural gas production is regulated by FERC and pipelines operating on or across the Outer Continental Shelf are subject to the Outer Continental Shelf Lands Act, which requires open-access, non-discriminatory pipeline facilities. Our production operations in the Gulf of Mexico and most of our operations in the western United States are located on federal oil and gas leases 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 and operational specifications and the plugging and abandonment of wells. Our production operations are also subject to numerous environmental regulations including regulations relating to oil spills into navigable waters of the United States. See *Regulation Federal Regulations* and *Regulation Environmental Regulation* for additional information.

Properties

Dominion E&P owns 6.3 trillion cubic feet of proved equivalent of natural gas and oil reserves and produces approximately 1.1 billion cubic feet equivalent of natural gas per day from its leasehold acreage and facility investments. We, either alone or with partners, 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 3.1 million acres, with another 2.4 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 activities of 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 weather effects.

Corporate

We also have a Corporate segment that includes:

- Our corporate, service company and other functions, including unallocated debt;
- Corporate-wide enterprise commodity risk management and optimization;
- 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; and
- Specific items attributable to our operating segments that are excluded from the profit measures evaluated by management in assessing segment performance or allocating resources among the segments.

Regulation

We are subject to regulation by the SEC, FERC, the Environmental Protection Agency (EPA), the Department of Energy (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 authorizing it to maintain and operate its electric facilities now in operation and to sell electricity to customers. However, it may not construct or incur financial commitments for construction of any substantial generating facilities or large capacity transmission lines without the prior approval of various state and federal government agencies.

Status of Electric Deregulation in Virginia

The Virginia Electric Utility Restructuring Act (Virginia Restructuring Act) was enacted in 1999 and established a plan to restructure the electric utility industry in Virginia. The Virginia Restructuring Act addressed, among other things: capped base rates, RTO participation, retail choice, the recovery of stranded costs, and the functional separation of a utility s electric generation from its electric transmission and distribution operations.

Retail choice has been available to all of our Virginia regulated electric customers since January 1, 2003. We have also separated our generation, distribution and transmission functions through the creation of divisions. State regulatory requirements ensure that our generation and other divisions operate independently and prevent cross-subsidies between Generation and other divisions.

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In 2004, the Virginia Restructuring Act and the Virginia fuel factor statute were amended. The amendments:

- Extend capped base rates to December 31, 2010, unless modified or terminated earlier under the Virginia Restructuring Act;
- Lock in our fuel factor provisions until the earlier of July 1, 2007 or the termination of capped rates under the Virginia Restructuring Act, with no adjustment for previously incurred over-recovery or under-recovery of fuel costs, thus eliminating deferred fuel accounting for the Virginia jurisdiction;
- Provide for a one-time adjustment of our fuel factor, effective July 1, 2007 through December 31, 2010 (unless capped rates are terminated earlier under the Virginia Restructuring Act), with no adjustment for previously incurred over-recovery or under-recovery of fuel costs; and
- End wires charges on the earlier of July 1, 2007 or the termination of capped rates.

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen, 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.

When our fuel factor is adjusted in July 2007, we will remain subject to the risk that fuel factor-related cost recovery shortfalls may adversely affect our margins. Conversely, we could experience a positive economic impact to the extent that we can reduce our fuel factor-related costs for our electric utility generation operations.

We anticipate that our unhedged natural gas and oil production will act as a natural internal hedge for fuel used in our electric utility generation operations. If gas and oil prices rise, it is expected that our exploration and production operations will earn greater profits that will help offset higher fuel costs and lower profits in our electric utility generation operations. Conversely, if gas and oil prices fall, it is expected that our electric utility generation operations will incur lower fuel costs and earn higher profits that will help mitigate lower profits in our exploration and production operations. We also anticipate that the fixed fuel rate will lessen the effect of variations in weather on our electric utility generation operations. During periods of mild weather it is expected that our electric utility generation operations will burn less high-cost fuel because customers will use less electricity, thereby mitigating decreased revenues. Alternatively, in periods of extreme weather, our higher fuel costs from running costlier plants are expected to be mitigated by additional revenues as customers use more electricity.

Other amendments to the Virginia Restructuring Act were enacted in 2004 with respect to a minimum stay exemption program, a wires charge exemption program and the development of a coal-fired generating plant in southwest Virginia for serving default service needs. Under the minimum stay exemption program, large customers with a load of 500kW or greater would be exempt from the twelve-month minimum stay obligation under capped rates if they return to supply service from the incumbent utility at market-based pricing after they have switched to supply service with a competitive service provider. The wires charge exemption program would allow large industrial and commercial customers, as well as aggregated customers in all rate classes, to avoid paying wires charges when selecting electricity supply service from a competitive service provider by agreeing to market-based pricing upon return to the incumbent utility. For 2006, our wires charges are set at zero for all rate classes. In February 2005, we joined a consortium to explore the development of a coal-fired electric power station in southwest Virginia.

Retail Access Pilot Programs

The three retail access pilot programs, approved by the Virginia Commission in 2003, continue to be available to customers. There are currently six competitive suppliers and seven aggregators registered with us and licensed to supply electricity to customers in Virginia. Currently, the relationship between capped rates and market prices makes customer switching difficult.

Rate Matters

Virginia In December 2003, the Virginia Commission approved the proposed settlement of our 2004 fuel factor increase of $386 million. The settlement includes a recovery period for the under-recovery balance over three and a half years. Approximately $171 million and $85 million of the $386 million was recovered in 2004 and 2005, respectively. The remaining unrecovered balance is expected to be recovered by July 1, 2007.

As a result of amendments to the Virginia Restructuring Act in 2004, our capped base rates were extended to December 31, 2010. In addition, our fuel factor provisions were frozen until July 1, 2007, at which time they will be adjusted once for the period through December 31, 2010. See *Status of Electric Deregulation in Virginia* for additional information regarding the Virginia Restructuring Act amendments.

North Carolina In connection with the North Carolina Commission s approval of the CNG acquisition, we agreed not to request an increase in North Carolina retail electric base rates before 2006, except for certain events that would have a significant financial impact on our electric utility operations. However, in 2004 the North Carolina Commission commenced an investigation into our North Carolina base rates and subsequently

ordered us to file a general rate case to show cause why our North Carolina base rates should not be reduced. The rate case was filed in September 2004 and in March 2005, the North Carolina Commission approved a settlement that included a prospective $12 million annual reduction in current base rates and a five-year base rate moratorium, effective as of April 2005.

Fuel rates are still subject to change under the annual fuel cost adjustment proceedings.

Gas

Our gas distribution service is regulated by the Ohio Commission, the Pennsylvania Commission and the West Virginia Commission.

Status of Gas Deregulation

Each of the three states in which we have gas distribution operations has enacted or considered legislation regarding 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, on our own initiative, offered retail choice to customers. At December 31, 2005, approximately 697,000 of our 1.2 million Ohio customers were participating in this open-access program. Large industrial customers in Ohio also source their own natural gas supplies. In April 2005, we filed an application with the Ohio Commission seeking approval of a plan to improve and expand our Energy Choice Program. See *Future Issues and Other Matters Ohio Energy Choice Pilot Program* in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A).

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Pennsylvania In Pennsylvania, supplier choice is available for all residential and small commercial customers. At December 31, 2005, approximately 75,000 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.

Rate Matters

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 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.

Ohio In December 2003, the Ohio Commission approved a joint application filed by us and several other Ohio natural gas companies for recovery of bad debt expenses via a rider known as a bad debt tracker. The tracker insulates us from the effect of changes in bad debt expense, which is affected by the volatility of natural gas prices, weather and prices charged by competitive retail natural gas suppliers. The tracker is an adjustable rate that recovers the cost of bad debt in a manner similar to a gas cost recovery rate. Instead of recovering bad debt costs through our base rates, we recover all eligible bad debt expenses through the bad debt tracker. Annually, we assess the need to adjust the tracker based on the preceding year s unrecovered deferred bad debt expense.

Pennsylvania In July 2004, the Pennsylvania Commission approved a settlement agreement between us and the Office of Consumer Advocate (OCA) in which the OCA agreed to drop its appeal of a previous Pennsylvania Commission order that allowed us to recover approximately $16.5 million in unrecovered purchased gas costs. As part of the settlement, all customer service and delivery charges will be fixed through December 31, 2008. Gas costs will continue to pass through to the customer through the purchased gas cost adjustment mechanism.

West Virginia In October 2005, the West Virginia Public Service Commission issued a final order approving a $32 million increase in our base and purchased gas cost recovery rates. Under the order, the combined increase for base and purchased gas recovery rates for the 2005/2006 winter is subject to a 20 percent cap. Accordingly, the purchased gas cost recovery rate reflected the effect of the increase effective November 1, 2005 through January 1, 2006. Beginning January 2006, the increase was applied to both base and purchased gas cost recovery rates, with $4 million of the $32 million attributable to the base rate. The order also provides for the recovery of interest costs for any gas cost under-recovery as a result of the cap.

In May 2005, FERC approved a comprehensive rate settlement with our subsidiary, Dominion Transmission, Inc. (DTI), and its customers and interested state commissions. The settlement, which became effective July 1, 2005, reduces our natural gas transportation and storage service revenues by approximately $49 million annually, through a combination of firm transportation rate reductions 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.

Federal Regulations

Energy Policy Act of 2005 (EPACT)

In August 2005, the President of the United States signed EPACT. Key provisions include the following:

- Repeal of the Public Utility Holding Company Act of 1935 (1935 Act);
- Establishment of a self-regulating electric reliability organization governed by an independent board with FERC oversight;

- Provision for greater regulatory oversight by other federal and state authorities;
- Extension of the Price Anderson Act for 20 years until 2025;
- Provision for standby financial support and production tax credits for new nuclear plants;
- Grant of enhanced merger approval authority to FERC;
- Provision of authority to FERC for the siting of certain electric transmission facilities if states cannot or will not act in a timely manner;
- Grant of exclusive authority to FERC to approve applications for construction of LNG facilities; and
- Improvement of the processes for approval and permitting of interstate pipelines.

Many of the changes Congress enacted must be implemented through public notice and proposed rule making by the federal agencies affected and this process is ongoing. We will continue to evaluate the effects that EPACT may have on our business.

Public Utility Holding Company Act of 2005 (PUHCA 2005)

EPACT provides for the repeal of the 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. Upon the effective date of repeal of the 1935 Act, we will be considered a holding company under PUHCA 2005, the rules and regulations of which will be 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

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sales tariff 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.

As required by the Virginia Restructuring Act, we joined an RTO and, in May 2005, integrated our electric transmission assets into the new PJM South Region.

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 gas pipeline subsidiaries, including Dominion Transmission, Inc. (DTI) and Dominion Cove Point LNG, LP. FERC also has jurisdiction over siting, construction and operation of natural gas import facilities and interstate natural gas pipeline facilities.

FERC Order 636 requires our transmission pipelines to operate as open-access transporters and provide transportation and storage services on an equal basis for all gas suppliers, whether purchased from us or from another gas supplier.

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

We are also subject to the Pipeline Safety Act of 2002, which includes mandates regarding the inspection frequency for interstate and intrastate natural gas transmission and storage pipelines located in areas of high-density population where the consequences of potential pipeline accidents pose the greatest risk to people and their property. We have evaluated our natural gas transmission and storage properties under the final regulations issued in December 2003 and have developed the required implementation plan including identification, testing and potential remediation activities.

We implemented various rate filings, tariff changes and negotiated rate service agreements for our FERC-regulated businesses during 2005. In all material respects, these filings were approved by FERC in the form requested by us and were subject to only minor modifications.

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.

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

In March 2005, the EPA Administrator signed both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule. These rules, when implemented, will require significant reductions in future 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 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. These regulatory actions will require additional reductions in emissions from our fossil fuel-fired generating facilities. In November 2005, we announced initial plans to spend approximately $500 million to install additional emission controls on our coal-fired stations in Virginia over the next 10 years to comply with these rules.

In March 2004, the State of North Carolina filed a petition with the EPA under Section 126 of the Clean Air Act seeking additional NO_X and SO_2 reductions from electrical generating units in thirteen states, claiming emissions from the electrical generating units in those states are contributing to air quality problems in North Carolina. We have electrical generating units in six of the thirteen states. The EPA has proposed to address the issues raised by North Carolina through the state s implementation of CAIR and is expected to issue a final rulemaking in March 2006. At this time, we do not anticipate additional expenditures beyond those that will be required to comply with the EPA CAIR regulations.

The United States Congress is considering 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 a variety of periods of up to 15 years. If these new proposals are adopted, we may incur additional significant expenditures to comply with the new standards.

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 are evaluating information from certain of our existing power stations and expect to spend approximately $16 million over the next 3 years conducting studies and technical evaluations. We cannot predict the outcome of the EPA regulatory process or state with any certainty what specific controls may be required.

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 precise financial effects of compliance obligations cannot be assessed until these regulations are finalized in early 2006. We do not expect the impact of these regulations on us to be material.

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

Nuclear Regulatory Commission

All aspects of the operation and maintenance of our nuclear power stations, which are part of the Dominion Generation segment, are regulated by the NRC. Operating licenses issued by the NRC are subject to revocation, suspension or modification,

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and the operation of a nuclear unit may be suspended if the NRC determines that the public interest, health or safety so requires.

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

The NRC also requires us to decontaminate 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.

Recent Developments

On March 1, 2006 we entered into an agreement with Equitable Resources, Inc. to sell two of our wholly-owned regulated gas distribution subsidiaries, The Peoples Natural Gas Company and Hope Gas, Inc. for $969.6 million plus adjustments to reflect capital expenditures and changes in working capital. We expect to complete the transaction by the first quarter of 2007, subject to state regulatory approvals in Pennsylvania and West Virginia as well as approval under the federal Hart-Scott-Rodino Act.

Where You Can Find More Information About Dominion

We file our annual, quarterly and current reports, proxy statements and other information with the 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.

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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 may require numerous permits, approvals and certificates from various governmental agencies. We must also comply with environmental legislation and associated regulations. Management believes 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 Virginia Restructuring Act, as amended in 2004, our base rates (excluding, generally, a fuel factor with limited adjustment provisions, and certain other allowable adjustments) remain capped through December 31, 2010 unless modified or terminated consistent with the Virginia Restructuring Act. Although the Virginia Restructuring 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 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, under the 2004 amendments to the Virginia fuel factor statute, our current Virginia fuel factor provisions are locked-in until the earlier of July 1, 2007 or the termination of capped rates by order of the Virginia Commission, with no deferred fuel accounting. The amendments provide for a one-time adjustment of our fuel factor, effective July 1, 2007 through December 31, 2010 (unless capped rates are terminated earlier), with no adjustment for previously incurred over-recovery or under-recovery. As a result of the current locked-in fuel factor and the uncertainty of what the one-time adjustment will be, 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.

Under the Virginia Restructuring Act, the generation portion of our electric utility operations is open to competition and resulting uncertainty. Under the Virginia Restructuring Act, the generation portion of our electric utility operations in Virginia is open to competition and is no longer subject to cost-based regulation. To date, a competitive retail market has been slow to develop. Consequently, it is difficult to predict the pace at which a competitive environment will evolve and the extent to which we will face increased competition and be able to operate profitably within this competitive environment.

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 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 manage 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 financial 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

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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.

Derivatives designated under hedge accounting to the extent not 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 exploration and production business is dependent on 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 damage to or suspension of operations caused by weather, fire, explosion or other events to our or third-party gas and oil facilities, fluctuations in natural gas and crude oil prices, results of future drilling and well completion activities, and our ability to acquire additional land positions in competitive lease areas, as well as inherent operational risks that could disrupt production.

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) in a given country at the end of any quarterly period, then a permanent write-down of the assets must be recognized in that period.

We maintain business interruption insurance for offshore operations associated with our exploration and production business. We have placed our insurers on notice that we have suffered substantial property damage and business interruption loss related to Hurricanes Katrina and Rita. Failure to realize the full value of our claims could adversely affect our results of operations. Additionally, the increased level of hurricane activity in the Gulf of Mexico is likely to significantly increase the cost of business interruption insurance and could make it unavailable on commercially reasonable terms. Inability to insure our offshore Gulf of Mexico operations could adversely affect our results of operations.

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, 2006, Dominion s senior unsecured debt is rated BBB, stable outlook, by Standard & Poor s Rating Group (Standard & Poor s); Baa1, under review for potential downgrade, 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 trading and marketing 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. Implementation of our growth strategy is dependent on our ability to recruit, retain and motivate employees. Competition for skilled employees in some areas is high and the inability to retain and attract these employees could adversely affect our business and future financial condition.

Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

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

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 and certain of our nonutility generation facilities are subject to liens.

Information detailing our gas and oil operations presented below and on the following page includes the activities of the Dominion E&P segment and the production activity of DTI, 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:

	2005		2004		2003	
	Proved Developed	**Total Proved**	Proved Developed	Total Proved	Proved Developed	Total Proved
Proved gas reserves (bcf)						
United States	**3,605**	**4,856**	3,591	4,814	3,474	4,718
Canada	**101**	**106**	94	96	360	443
Total proved gas reserves	**3,706**	**4,962**	3,685	4,910	3,834	5,161
Proved oil reserves (000 bbl)						
United States	**145,735**	**198,602**	102,152	144,007	55,530	149,707
Canada	**7,154**	**19,096**	11,840	20,055	32,849	54,802
Total proved oil reserves	**152,889**	**217,698**	113,992	164,062	88,379	204,509
Total proved gas and oil reserves (bcfe)	**4,623**	**6,268**	4,369	5,894	4,364	6,388

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, 2005 are based upon studies for each of our properties prepared by our staff engineers and reviewed 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:

	2005	2004	2003
Gas production (bcf)			
United States	275	312	335
Canada	15	36	40
Total gas production	290	348	375
Oil production (000 bbl)			
United States	14,714	11,258	9,612
Canada	861	2,525	2,639
Total oil production	15,575	13,783	12,251
Total gas and oil production (bcfe)	383	431	449

The average sales price per thousand cubic feet (mcf) of gas with hedging results (including transfers to other Dominion operations at market prices) realized during the years 2005, 2004 and 2003 was $4.79, $4.14 and $4.00, respectively. The respective average prices without hedging results per mcf of gas produced were $8.01, $5.77 and $5.10. The respective average sales prices realized for oil with hedging results were $30.46, $25.22 and $23.51 per barrel and the respective average prices without hedging results were $49.48, $35.49 and $27.43 per barrel. The average production (lifting) cost per mcf equivalent of gas and oil produced (as calculated per SEC guidelines) during the years 2005, 2004 and 2003 was $1.16, $0.91 and $0.80, respectively.

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Acreage

Gross and net developed and undeveloped acreage at December 31, 2005 was:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
(thousands)				
United States	4,310	2,610	3,431	1,875
Canada	950	474	698	519
Total	5,260	3,084	4,129	2,394

Net Wells Drilled in the Calendar Year

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

	2005	2004	2003
Exploratory:			
United States			
Productive	6	7	8
Dry	6	7	7
Total United States	12	14	15
Canada			
Productive		34	10
Dry		7	1
Total Canada		41	11
Total Exploratory	12	55	26
Development:			
United States			
Productive	909	921	819
Dry	34	17	36
Total United States	943	938	855
Canada			
Productive	59	36	31
Dry	5	3	10
Total Canada	64	39	41
Total Development	1,007	977	896
Total wells drilled (net):	1,019	1,032	922

As of December 31, 2005, 149 gross (99 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, 2005, follows:

	Gross	Net
Gas wells:		
United States	20,624	13,769

Canada	671	427
Total gas wells	21,295	14,196
Oil wells:		
United States	3,445	889
Canada	394	149
Total oil wells	3,839	1,038

The number of productive wells includes 208 gross (80 net) multiple completion gas wells and 10 gross (4 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 our generating units and capability, as of December 31, 2005.

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	441(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	312
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	1,607(d)
Gaston	Roanoke Rapids, NC	Hydro	225
Roanoke Rapids	Roanoke Rapids, NC	Hydro	99
Pittsylvania	Hurt, VA	Wood	80
Other	Various	Various	15
			15,515(e)
Merchant Generation			
Millstone	Waterford, CT	Nuclear	1,951(f)
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(g)
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	704(h)
Armstrong (CT)	Shelocta, PA	Gas	625(c)
Troy (CT)	Luckey, OH	Gas	600(c)

Manchester (CC)	Providence, RI	Gas	432
Pleasants (CT)	St. Mary s, WV	Gas	313(c)
Other	Various	Various	17
			10,294
Purchased Capacity			2,244
		Total Capacity	**28,053**

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) Totals may not add due to rounding.
(f) Excludes 6.53 percent undivided interest in Unit 3 owned by Massachusetts Municipal Wholesale Electric Company and Central Vermont Public Service Company.
(g) Excludes 50 percent partnership interest owned by Cogen Technologies Morgantown, Ltd. and Hickory Power Corporation.
(h) Excludes 50 percent partnership interest owned by Peoples Elwood, LLC.

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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 rate matters and various regulatory proceedings to which we are a party.

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. The plaintiffs claim that they have suffered damages, including property damage and lost profits, as a result of the alleged plume and seek compensation for these items.

In July 1997, Jack Grynberg brought suit against CNG and several of its subsidiaries. The suit seeks damages for alleged fraudulent mismeasurement 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. While some of the defendants have been dismissed from the case, the court denied the motion to dismiss filed by the CNG companies and we appealed. The case is stayed pending a ruling, which is not expected until the second quarter of 2006.

In April 1998, Harrold E. (Gene) Wright filed suit against Dominion Exploration & Production, Inc. (formerly known as CNG Producing Company), a subsidiary of CNG, and numerous other companies under the False Claims Act. 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 2005, DTI reached an agreement in principle on a proposed Consent Order and Agreement (COA) with the Pennsylvania Department of Environmental Protection (PADEP) which would supersede a 1990 COA between the parties. The agreement in principle resolves longstanding groundwater contamination issues at several DTI compressor stations in Pennsylvania and includes a penalty and environmental projects of $850,000 to be paid to PADEP and the Pennsylvania Department of Conservation and Natural Resources to resolve alleged violations. Negotiations are ongoing with both agencies to finalize language and payment mechanisms. As of December 31, 2005, DTI has accrued $850,000 for the penalty and environmental projects.

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 (51)	President and Chief Executive Officer of Dominion from January 2006 to date; Chairman of the Board of Directors and Chief Executive Officer of Virginia Electric and Power Company from February 2006 to date; Chairman of the Board of Directors, President and Chief Executive Officer of Consolidated Natural Gas Company from January 2006 to date; President and Chief Operating Officer of Dominion from January 2004 to December 2005; President and Chief Operating Officer of Consolidated Natural Gas Company from January 2004 to December 2005; Executive Vice President of Dominion from March 1999 to December 2003; President and Chief Executive Officer of Virginia Electric and Power Company from December 2002 to December 2003; Executive Vice President of Consolidated Natural Gas Company from January 2000 to December 2003; Chief Executive Officer of Virginia Electric and Power Company from May 1999 to December 2002.
Thomas N. Chewning (60)	Executive Vice President and Chief Financial Officer of Dominion from May 1999 to date; Executive Vice President and Chief Financial Officer of Consolidated Natural Gas Company from January 2000 to date.
Jay L. Johnson (59)	Executive Vice President of Dominion from December 2002 to date; President and Chief Operating Officer-Delivery of Virginia Electric and Power Company from February 2006 to date; President and Chief Executive Officer of Virginia Electric and Power Company from December 2002 to January 2006; Senior Vice President, Business Excellence, Dominion Energy, Inc. from September 2000 to December 2002.
Duane C. Radtke (57)	Executive Vice President of Dominion and Consolidated Natural Gas Company from April 2001 to date; President of Devon Energy International from August 2000 to April 2001.
Mary C. Doswell (47)	Senior Vice President and Chief Administrative Officer of Dominion from January 2003 to date; President and Chief Executive Officer of Dominion Resources Services, Inc. from January 2004 to date; President of Dominion Resources Services, Inc. from January 2003 to December 2003; Vice President Billing and Credit of Virginia Electric and Power Company from October 2001 to December 2002; Vice President Metering of Virginia Electric and Power Company from January 2000 to October 2001.
Paul D. Koonce (46)	President and Chief Operating Officer-Energy of Virginia Electric and Power Company from February 2006 to date; Chief Executive Officer Energy of Virginia Electric and Power Company from January 2004 to January 2006; Chief Executive Officer Transmission of Virginia Electric and Power Company from January 2003 to December 2003; Senior Vice President Portfolio Management of Virginia Electric and Power Company from January 2000 to December 2002.
Mark F. McGettrick (48)	President and Chief Operating Officer-Generation of Virginia Electric and Power Company from February 2006 to date; President and Chief Executive Officer Generation of Virginia Electric and Power Company from January 2003 to January 2006; Senior Vice President and Chief Administrative Officer of Dominion from January 2002 to December 2002; President of Dominion Resources Services, Inc. from October 2002 to January 2003; Senior Vice President Customer Service and Metering of Virginia Electric and Power Company from January 2000 to December 2001.
Eva S. Hardy (61)	Senior Vice President External Affairs & Corporate Communications of Dominion from May 1999 to date.
G. Scott Hetzer (49)	Senior Vice President and Treasurer of Dominion from May 1999 to date; Senior Vice President and Treasurer of Virginia Electric and Power Company and Consolidated Natural Gas Company from January 2000 to date.
James L. Sanderlin (64)	Senior Vice President Law of Dominion from September 1999 to date; Senior Vice President Law of Consolidated Natural Gas Company from January 2000 to date.
Steven A. Rogers (44)	Vice President, Controller and Principal Accounting Officer of Dominion and Consolidated Natural Gas Company and Vice President and Principal Accounting Officer of Virginia Electric and Power Company from June 2000 to date.

Any service listed for Virginia Electric and Power Company, Consolidated Natural Gas Company, Dominion Resources Services, Inc. and Dominion Energy, Inc. reflects service at a subsidiary of Dominion.

In May 2004, we sold our telecommunications subsidiary, Dominion Telecom, Inc., to a third party and Dominion Telecom, Inc. became Elantic Telecom, Inc. Subsequent to the sale, Elantic Telecom, Inc. filed for protection under Chapter 11 of the U.S. Federal Bankruptcy code. Messrs. Johnson and Hetzer served as executive officers of Dominion Telecom, Inc. during the two years prior to its sale.

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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, 2005, there were approximately 168,000 registered shareholders, including approximately 74,000 certificate holders. The quarterly information concerning stock prices and dividends is incorporated by reference from Note 30 to the Consolidated Financial Statements. Restrictions on our payment of dividends are discussed in Note 21 to the Consolidated Financial Statements.

During 2005, we issued 116 shares of common stock to a former employee as a deferred payment under a 1985 performance 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 2005.

Issuer Purchases of Equity Securities

Period		(a) Total Number of Shares (or Units) Purchased	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased under the Plans or Program
10/1/05	10/31/05			N/A	21,275,000 shares/$1.72 billion
11/1/05	11/30/05	201(1)	$77.65	N/A	21,275,000 shares/$1.72 billion
12/1/05	12/31/05			N/A	21,275,000 shares/$1.72 billion
Total		201	$77.65	N/A	21,275,000 shares/$1.72 billion

(1) Amount represents registered shares tendered by employees to satisfy tax withholding obligations on vested restricted stock.

Item 6. Selected Financial Data

(millions, except per share amounts)	2005(1)	2004(2)	2003(3)	2002	2001(4)
Operating revenue	$ 18,041	$ 13,991	$ 12,095	$ 10,215	$ 10,560
Income from continuing operations before cumulative effect of changes in accounting principles	1,034	1,264	949	1,362	544
Income (loss) from discontinued operations, net of tax(5)	5	(15)	(642)		
Cumulative effect of changes in accounting principles, net of tax	(6)		11		
Net income	1,033	1,249	318	1,362	544
Income from continuing operations before cumulative effect of changes in accounting principles per common share basic	3.02	3.84	2.99	4.85	2.17
Net income per common share basic	3.02	3.80	1.00	4.85	2.17
Income from continuing operations before cumulative effect of changes in accounting principles per common share diluted	3.00	3.82	2.98	4.82	2.15
Net income per common share diluted	3.00	3.78	1.00	4.82	2.15
Dividends paid per share	2.68	2.60	2.58	2.58	2.58
Total assets	52,660	45,418	43,546	39,239	36,044
Long-term debt(6)	14,653	15,507	15,776	12,060	12,119

Preferred securities of subsidiary trusts[6]	1,397	1,132

(1) 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.

(2) Includes a $112 million after-tax charge related to our interest in a long-term power tolling contract that was divested in 2005 and a $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.

(3) Includes $122 million of after-tax incremental restoration expenses associated with Hurricane Isabel. Also in 2003, we adopted accounting standards that resulted in the recognition of the cumulative effect of changes in accounting principles. See Note 3 to our Consolidated Financial Statements.

(4) Includes a $97 million after-tax charge representing exposure to the Enron Corp. bankruptcy and $68 million of after-tax charges associated with a senior management restructuring initiative.

(5) Reflects 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 Financial Accounting Standards Board Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, 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. See Note 3 to our Consolidated Financial Statements.

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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
- Introduction
- Accounting Matters
- Results of Operations
- Segment Results of Operations
- Selected Information Energy Trading Activities
- Sources and Uses of Cash
- Future Issues and Other Matters

Forward-Looking Statements

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

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

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events, including hurricanes and winter storms, that can cause outages, production delays and property damage to our facilities;
- State and federal legislative and regulatory developments, including deregulation and changes in 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 the 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;
- Realization of expected business interruption insurance proceeds;
- Transitional issues related to the transfer of control over our electric transmission facilities to a regional transmission organization;
- Political and economic conditions, including the threat of domestic terrorism, inflation and deflation; and
- Completing the divestiture of investments held by our financial services subsidiary, Dominion Capital, Inc. (DCI).

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 energy company headquartered in Richmond, Virginia. Our strategy is to be a leading provider of electricity, natural gas and related services to customers in the energy intensive Northeast, Mid-Atlantic and Midwest regions of the United States. This area represents about a quarter of the nation s landmass, but accounts for approximately 40 percent of energy consumed. Our diversified portfolio of assets includes approximately:

- 28,100 megawatts of generation capacity;
- 7,800 miles of interstate natural gas transmission, gathering and storage pipeline;
- 6,000 miles of electric transmission lines;
- 6.3 trillion cubic feet equivalent of proved gas and oil reserves; and
- an underground natural gas storage system with 950 billion cubic feet of capacity, the nation s largest.

Our businesses are managed through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion Exploration & Production. 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 business, as well as non -

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regulated 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.

Revenue provided by 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 they are permitted to charge, to recover costs and earn a reasonable return on their capital investments. Variability 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.

Dominion Energy includes our tariff-based electric transmission, natural gas transmission pipeline and storage businesses and the Cove Point liquefied natural gas (LNG) facility. It also includes certain natural gas production located in the Appalachian basin and producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage, associated gas trading and the prior year s results of certain energy trading activities exited in December 2004. The electric transmission business serves Virginia and northeastern North Carolina and on May 1, 2005, became a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO). As a result, we integrated our control area into the PJM energy markets. The gas transmission pipeline and storage business serves Dominion s gas distribution businesses and other customers in the Northeast, Mid-Atlantic and Midwest.

Revenue provided by regulated electric and gas transmission operations and the LNG facility is based primarily on rates approved by the Federal Energy Regulatory Commission (FERC). The profitability of these businesses is dependent on their ability, through the rates they are permitted to charge, to recover costs and earn a reasonable return on their capital investments. Variability results from changes in rates, the demand for services, which is primarily weather dependent, and operating and maintenance expenditures (including labor and benefits).

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 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 as well as energy marketing and risk management activities associated with the optimization of 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 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, when a one-time prospective adjustment will be made effective through December 2010. Changes in our utility operating costs, particularly with respect to fuel and purchased power, relative to costs used to establish the rates, will impact Dominion Generation s 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. 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.

Dominion Exploration & Production (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, and Western Canada.

Dominion E&P generates income from the sale of natural gas and oil we produce from our reserves. Variability 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. We attempt to mitigate the financial impact of storm-related delays in production by maintaining business interruption insurance for our offshore operations. Our business interruption insurance covers delays caused by damage to both our production facilities and to third-party facilities downstream.

Corporate includes the operations of our corporate, service company and other operations (including unallocated debt), corporate-wide enterprise commodity risk management and optimization 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 specific items attributable to our operating segments that are

excluded from the profit measures evaluated by management in assessing segment performance or allocating resources among the segments.

Accounting Matters

Critical Accounting Policies and Estimates

We have identified the following accounting policies, including certain inherent estimates, that as a result of the judgments, uncertainties, uniqueness and complexities of the underlying accounting standards and operations involved, could result in material changes to our financial condition or results of operations under different conditions or using different assumptions. We have discussed the development, selection and disclosure of each of these policies with our Audit Committee.

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 on our

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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 in the circumstances and applied consistently from period to period. If pricing information is not available from external sources, judgment is required to develop the estimates of fair value. For individual contracts, the use of different valuation models or assumptions could have a material effect on the contract s estimated fair value.

For cash flow hedges of forecasted transactions, we must estimate the future cash flows of the forecasted transactions, as well as evaluate the probability of occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could 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, 2005, we reported $4.3 billion of goodwill on 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 Exploration & Production 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 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. In 2003, impairment charges of $78 million were recognized as a result of interim tests conducted for certain DCI subsidiaries and our discontinued telecommunications business.

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 2005 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, indicating 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 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 our judgment in areas such as identifying circumstances indicating 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 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 2005, we tested a group of gas and steam turbines held for future development with a carrying amount of $187 million for impairment. The results of our analysis indicated that these assets were not impaired. 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. In 2003, reflecting a significant revision in long-term expectations for potential growth in telecommunications service revenue, we approved a strategy to sell our interest in the telecommunications business. In

connection with this change in strategy, we tested the network assets to be sold for impairment, using the revised long-term expectations for potential growth. Our assets were determined to be substantially impaired and were written down to fair value. We sold our telecommunications business in 2004.

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 tangible 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 on our Consolidated Balance Sheets were measured during a period of historically low interest rates. The impact on measurements of new AROs, using different rates in the future, may be significant. In the future, if we revise any assumptions used to calculate the fair value of existing AROs, we will adjust the carrying amount of

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both the ARO liability and related long-lived asset. We record accretion expense, increasing the ARO liability, with the passage of time. In 2005, 2004 and 2003, we recognized $102 million, $91 million and $86 million, respectively, of accretion expense, and expect to incur $124 million in 2006.

A significant portion of our AROs relate to the future decommissioning of our nuclear facilities. At December 31, 2005, nuclear decommissioning AROs, which are reported in the Dominion Generation segment, totaled $1.7 billion, representing approximately 77% 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 experts periodic site-specific base year cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our utility nuclear plants. We use internal and external cost studies for our merchant nuclear facilities based on similar methods. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual results. In addition, these cost estimates are dependent on subjective factors, including the selection of cost escalation rates, which we consider to be a critical assumption.

We determine cost escalation rates, which represent projected cost increases over time, due to both general inflation and increases in the cost of specific decommissioning activities, for each of our nuclear facilities. The use of alternative rates would have been material to the liabilities recognized. For example, had we increased the cost escalation rate by 0.5%, the amount recognized as of December 31, 2005 for our AROs related to nuclear decommissioning would have been $343 million higher.

Employee benefit plans

We sponsor noncontributory defined benefit pension plans and other postretirement benefit plans for eligible active employees, retirees and qualifying dependents. The 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 selection of 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. The strategic target asset allocation for our pension fund is 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 2005, 2004 and 2003. We calculated our 2005 other postretirement benefit cost using an expected return on plan assets assumption of 8.00% compared to 7.79% and 7.78% for 2004 and 2003, respectively. 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 and because other postretirement benefit activity, unlike the pension activity, was partially taxable in 2004 and 2003.

Discount rates are determined 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 rate used to calculate 2005 pension and other postretirement benefit costs was 6.00% compared to the 6.25% and 6.75% discount rates used to calculate 2004 and 2003 pension and other postretirement benefit costs, respectively. Lower long-term bond yields were the primary reason for the decline in the discount rate from 2004 to 2005.

The medical cost trend rate assumption is established 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, 2005 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:

Actuarial Assumption	Change in Assumption	Increase in Net Periodic Cost	
		Pension Benefits	Other Postretirement Benefits
		(millions)	
Discount rate	(0.25)%	$14	$ 7
Rate of return on plan assets	(0.25)%	10	2
Healthcare cost trend rate	1%	N/A	26

In addition to the effects on cost, a 0.25% decrease in the discount rate would increase our projected pension benefit obligation by $138 million and would increase our accumulated postretirement benefit obligation by $53 million.

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. Specifically, our regulated businesses record assets and liabilities that nonregulated companies would not report under accounting principles generally accepted in the United States of America. 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

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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 regulated 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 regulatory assets is determined to be less than probable, the regulatory asset will be written off and an expense will be recorded in the period such assessment is made. We currently believe the recovery of our 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 exploration and production 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 depreciated using the units-of-production method. The depreciable 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 depreciable 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 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, 2005 are based upon studies for each of our properties prepared by our staff engineers and reviewed 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 them differently. We establish liabilities for tax-related contingencies in accordance with Statement of Financial Accounting Standards (SFAS) No. 5, *Accounting for Contingencies,* and review them in light of changing facts and circumstances. 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. In addition, 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 2005, 2004 and 2003, we were required to adopt several new accounting standards, the requirements of which are discussed in Note 3 to our Consolidated Financial Statements. The adoption of Financial Accounting Standards Board (FASB) Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities.* (FIN 46R) on December 31, 2003 with respect to special purpose entities, affected the comparability of our 2005 and 2004 Consolidated Statements of Income to 2003 s as follows:

- We were required to consolidate certain variable interest lessor entities through which we had financed and leased several new power generation projects, as well as our corporate headquarters and aircraft. In 2005 and 2004, our Consolidated Statements of Income reflect depreciation expense on the net property, plant and equipment and interest expense on the debt associated with these entities, whereas in 2003 the lease payments to these entities were reflected as rent expense in other operations and maintenance expense.
- In addition, under FIN 46R, we report as long-term debt our junior subordinated notes held by five capital trusts, rather than the trust preferred securities issued by those trusts. As a result, in 2005 and 2004 we reported interest expense on the junior subordinated notes rather than preferred distribution expense on the trust preferred securities.

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 are now 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

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the reclassified contracts were previously presented in operating revenue on a net basis. Upon reclassification as non-trading, all unrealized changes in fair value and settlements related to those derivative contracts that are financially settled are now reported in other operations and maintenance expense. The statement of income related amounts for those reclassified derivative sales contracts that are physically settled are now presented in operating revenue, while the statement of income related amounts for physically settled purchase contracts are reported in operating expenses.

Crude Oil Buy/Sell Arrangements

We enter into buy/sell and related agreements primarily as a means to reposition our offshore Gulf of Mexico crude oil production to more liquid marketing locations onshore. We typically enter into either a single or a series of buy/sell transactions in which we sell our crude oil production at the offshore field delivery point and buys similar quantities at Cushing, Oklahoma for sale to third parties. We are able to enhance profitability by selling to a wide array of refiners and/or trading companies at Cushing, one of the largest crude oil markets in the world, versus restricting sales to a limited number of refinery purchasers in the Gulf of Mexico.

Under the primary guidance of EITF Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*, we present the sales and purchases related to our crude oil buy/sell arrangements on a gross basis in our Consolidated Statements of Income. These transactions require physical delivery of the crude oil and the risks and rewards of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling and counterparty nonperformance risk. Amounts currently shown on a gross basis in our Consolidated Statements of Income are summarized below.

Year Ended December 31, (millions)	**2005**	2004	2003
Sale activity included in operating revenue	**$377**	$290	$181
Purchase activity included in operating expenses[1]	**362**	271	163

(1) Included in other energy-related commodity purchases

In September 2005, the FASB ratified the EITF s consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, that will require buy/sell and related agreements to be presented on a net basis in our Consolidated Statements of Income if they are entered into in contemplation of one another. This new guidance is required to be applied to all new arrangements entered into, and modifications or renewals of existing arrangements, for reporting periods beginning April 1, 2006. We are currently assessing the impact that this new guidance may have on our income statement presentation of these transactions; however, there will be no impact on our results of operations or cash flows. See Note 4 to our Consolidated Financial Statements.

Results of Operations

Presented below is a summary of our consolidated results:

Year Ended December 31, (millions, except EPS)	**2005**	**$ Change**	2004	$ Change	2003
Net Income	**$ 1,033**	**$ (216)**	$ 1,249	$931	$ 318
Diluted earnings per share (EPS)	**3.00**	**(0.78)**	3.78	2.78	1.00

Overview

2005 vs. 2004

Our 2005 results were significantly impacted by Hurricanes Katrina and Rita, 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 exploration and production operations, gains on the sale of excess 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 megawatts (Dominion New England) and in July 2005, we completed the acquisition of the 556-megawatt Kewaunee nuclear power station (Kewaunee).

2004 vs. 2003

Our results for 2004 improved dramatically reflecting the absence of $750 million of after-tax losses recognized in 2003 associated with our discontinued telecommunications business that we sold in May 2004. Other positive drivers included higher average realized gas and oil prices and a favorable change in the fair value of certain oil options held by our exploration and production operations. These positives were partially offset by increased fuel expenses incurred by electric utility operations as a result of the elimination of deferred fuel accounting, a loss from energy trading and marketing activities reflecting comparatively lower price volatility on natural gas option positions and the effect of unfavorable price changes on electric trading margins and an after-tax charge related to our interest in a long-term power tolling contract that was divested in 2005, in connection with our exit from certain energy trading activities.

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Analysis of Consolidated Operations

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

Year ended December 31, (millions)	2005	$ Change	2004	$ Change	2003
Operating Revenue	$ 18,041	$4,050	$ 13,991	$1,896	$ 12,095
Operating Expenses					
Electric fuel and energy purchases	4,713	2,551	2,162	495	1,667
Purchased electric capacity	505	(82)	587	(20)	607
Purchased gas	3,941	1,014	2,927	752	2,175
Other energy-related commodity purchases	1,391	402	989	543	446
Other operations and maintenance	3,058	292	2,766	(181)	2,947
Depreciation, depletion and amortization	1,412	107	1,305	89	1,216
Other taxes	582	63	519	43	476
Other income (loss)	168	1	167	207	(40)
Interest and related charges	991	52	939	(36)	975
Income tax expense	582	(118)	700	103	597
Income (loss) from discontinued operations, net of tax	5	20	(15)	627	(642)
Cumulative effect of changes in accounting principles, net of tax	(6)	(6)		(11)	11

An analysis of our results of operations for 2005 compared to 2004 and 2004 compared to 2003 follows.

2005 vs. 2004

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

- A $1.9 billion increase in nonregulated electric sales primarily due to a $1.1 billion increase 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. The increase also reflects 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 on *Operating Revenue* was offset by similar changes in *Other operations and maintenance expense* and *Electric fuel and energy purchases expense;*
- An $863 million increase in nonregulated gas sales largely reflecting a $588 million increase from gas aggregation activities and nonregulated retail energy marketing operations primarily due to higher prices, a $110 million increase due to higher natural gas prices related to market-based services for the optimization of transportation and storage assets, partially offset by the effect of unfavorable price changes on unsettled contracts and a $110 million increase in sales of gas purchased by exploration and production operations to facilitate gas transportation and satisfy other agreements. The increases in revenue from gas aggregation activities, nonregulated retail energy marketing operations and exploration and production operations were largely offset by corresponding increases in *Purchased gas expense*;
- A $400 million increase in other energy-related commodity sales reflecting a $276 million increase in nonutility coal sales resulting from higher coal prices ($171 million) and increased sales volumes ($105 million), an $87 million increase in sales of purchased oil by exploration and production operations and a $37 million increase in sales of emissions allowances held for resale primarily due to higher prices. This increase was largely offset by a corresponding increase in *Other energy-related commodity purchases expense*;
- A $363 million increase in regulated electric sales 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 in regulated gas sales primarily related to the recovery of higher gas prices. The effect of this increase was offset by a comparable increase in *Purchased gas expense*.

Operating Expenses

Electric fuel and energy purchases expense increased 118% 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 congestion costs associated with PJM; 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 $505 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 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

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increase related to exploration and production, all of which are discussed in *Operating Revenue*.

Other energy-related commodity purchases expense increased 41% to $1.4 billion, primarily reflecting a $263 million increase in the cost of coal purchased for resale, a $91 million increase related to purchases of oil by exploration and production operations, and a $47 million increase in emissions allowances purchased for resale, all of which are discussed in *Operating Revenue*.

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 Hurricanes Katrina and Rita;
- 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 exploration and production 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 financial transmission rights we received from PJM as a load-serving entity to offset the congestion costs associated with PJM spot market activity, which are included in *Electric fuel and energy purchases expense*;
- A $139 million gain resulting from the sale of excess emissions allowances. Future sales, if any, are dependent on market liquidity and other factors;
- 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
  - A $120 million benefit due to favorable changes in the fair value of certain oil options related to exploration and production operations.

Depreciation, depletion and amortization expense (DD&A) 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 $582 million, primarily due to higher property taxes resulting from the Dominion New England power plants and higher severance taxes associated with increased commodity prices.

2004 vs. 2003

Operating Revenue increased 16% to $14.0 billion, primarily reflecting:

- A $684 million increase in other energy-related commodity sales reflecting a $384 million increase in nonutility coal sales resulting from higher coal prices and increased sales volumes, a $120 million increase in sales of emissions allowances held for resale due to higher prices and increased sales volumes and a $109 million increase in sales of purchased oil by exploration and production operations. This increase was largely offset by corresponding increase in *Other energy-related commodity purchases expense*;
- A $364 million increase in nonregulated gas sales reflecting a $410 million increase in revenue from gas aggregation activities and nonregulated retail energy marketing operations, due to higher prices and increased volumes and a $61 million increase in revenue from sales of gas purchased by exploration and production operations to facilitate gas transportation and satisfy other agreements, partially offset by a $108 million decrease in revenue from energy trading and marketing activities due to comparatively lower price volatility on natural gas option positions. The

increases related to gas aggregation activities, nonregulated retail energy marketing operations and exploration and production operations were largely offset by corresponding increases in *Purchased gas expense*;

- A $304 million increase in regulated electric sales reflecting a $231 million increase due to the impact of a comparatively higher fuel rate on increased sales volumes and a $49 million increase from customer growth associated with new customer connections. The rate increase resulted from the settlement of a Virginia fuel rate case in December 2003. This increase was more than offset by an increase in *Electric fuel and energy purchases expense*;
- A $164 million increase in regulated gas sales reflecting a $198 million increase due to higher rates for regulated gas distribution operations primarily related to the recovery of higher gas prices and a $20 million increase resulting from the return of customers from Energy Choice programs, partially offset by an $87 million decrease associated with milder weather and lower industrial sales. The effect of this net increase was largely offset by a comparable increase in *Purchased gas expense;*

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- A $133 million increase in gas and oil production revenue primarily reflecting a $97 million increase in revenue from gas production primarily due to higher average realized prices and a $36 million increase in revenue from oil production primarily reflecting higher volumes; and
- A $119 million increase in nonregulated electric sales reflecting a $181 million increase in revenue from nonregulated retail energy marketing operations largely due to increased volumes and a $97 million increase in revenue from merchant generation operations, largely due to the commencement of commercial operations at Fairless in June 2004, partially offset by decreased revenue at certain other stations resulting from lower output. These increases were partially offset by a $140 million decrease in revenue from energy trading and marketing activities reflecting decreased margins in electric trading due to unfavorable price movements.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 30% to $2.2 billion, primarily reflecting:

- A $408 million increase related to regulated utility operations resulting from the combined effects of an increase in the fixed fuel rate and the elimination of fuel deferral accounting for the Virginia jurisdiction, which resulted in the recognition of fuel expenses in excess of amounts recovered in fixed fuel rates. The increase also reflects higher generation output;
- A $162 million increase related to nonregulated retail energy marketing operations discussed in *Operating Revenue*;
- An $88 million increase related to merchant generation operations, largely due to the addition of Fairless, partially offset by decreased fuel expense at certain other stations resulting from lower generation output; partially offset by
- A $163 million decrease related to energy marketing and risk management activities.

Purchased gas expense increased 35% to $2.9 billion, principally resulting from:

- A $357 million increase associated with gas aggregation activities and nonregulated retail energy marketing operations discussed in *Operating Revenue*;
- A $130 million increase associated with regulated gas distribution operations discussed in *Operating Revenue*;
- A $66 million increase from gas transmission operations due to increased gathering and extraction activities and higher gas usage; and
- A $58 million increase associated with exploration and production operations discussed in *Operating Revenue*.

Other energy-related commodity purchases expense increased 122% to $989 million, primarily reflecting a $348 million increase in coal purchased for resale, a $108 million increase related to purchases of oil by our exploration and production operations and a $105 million increase in the cost of emissions allowances purchased for resale, each of which are discussed in *Operating Revenue*.

Other operations and maintenance expense decreased 6% to $2.8 billion, resulting from:

- A $113 million net benefit due to favorable changes in the fair value of certain oil options related to exploration and production operations. During 2004, we effectively settled certain oil options not designated as hedges by entering into offsetting option positions that had the effect of preserving approximately $120 million in mark-to-market gains attributable to favorable changes in time value; and
- The impact of the following charges recognized in 2003:
  - A $197 million charge representing incremental electric utility restoration expenses associated with Hurricane Isabel;
  - A $108 million charge from asset and goodwill impairments associated with DCI s financial services operations;
  - A $105 million charge associated with the termination of certain long-term power purchase agreements;
  - A $64 million charge for the restructuring of certain electric sales contracts recorded as derivative assets;
  - A $60 million goodwill impairment associated with the purchase of the remaining interest in the telecommunications joint venture, Dominion Fiber Ventures, LLC (DFV), held by another party;
  - A $28 million charge related to severance costs for workforce reductions; and
  - A $22 million impairment related to CNG International s (CNGI) generation assets that were sold in December 2003.

These benefits were partially offset by the following charges and incremental expenses recognized in 2004:

- A $184 million charge related to the sale of our interest in a long-term power tolling contract;
- 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;
- A $71 million net charge associated with the termination of certain long-term power purchase agreements;
- An approximate $60 million increase in costs related to gas and oil production activities;
- An $18 million increase in reliability expenses associated with utility operations primarily due to increased tree-trimming;

- A $13 million increase related to salaries, wages and benefits resulting from a $60 million increase in pension and medical benefits and a $46 million increase due to wage increases and other factors, partially offset by an $89 million decrease in incentive-based compensation expense due to failure to meet targeted earnings goals; and
- A $10 million charge associated with the sale of our natural gas and oil assets in British Columbia, Canada.

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Depreciation, depletion and amortization expense increased 7% to $1.3 billion, largely due to incremental depreciation expense resulting from property additions, including those resulting from the consolidation of certain variable interest entities as a result of adopting FIN 46R at December 31, 2003.

Other taxes increased 9% to $519 million, primarily due to higher gross receipts taxes and higher severance and property taxes associated with increased commodity prices.

Other income increased to $167 million from a net loss of $40 million in 2003, primarily reflecting:

- A $61 million increase resulting from net realized gains (including investment income) associated with nuclear decommissioning trust fund investments as opposed to net realized losses (net of investment income) in 2003;
- A $23 million benefit associated with the disposition of CNGI s investment in Australian pipeline assets that were sold during 2004; and
- The impact of the following charges recognized in 2003, which did not recur in 2004:
  - $57 million of costs associated with the acquisition of DFV senior notes;
  - $27 million for the reallocation of equity losses between us and the minority interest owner of DFV; and
  - A $62 million impairment of CNGI s investment in Australian pipeline assets held for sale.

Income tax expense Our effective tax rate decreased 3.0% to 35.6% for 2004, reflecting an increase in the valuation allowance for 2003 with no comparable increase in 2004, partially offset by increases in 2004 in utility plant differences and other factors.

Loss from discontinued operations decreased to $15 million from $642 million, primarily reflecting the sale of our discontinued telecommunications operations during May 2004 and the impact of the following charges recognized in 2003:

- Impairment of network assets and related inventories of $566 million. We did not recognize any deferred tax benefits related to the impairment charges, since realization of tax benefits was not anticipated at the time based on our expected future tax profile. In addition, we increased the valuation allowance on deferred tax assets recognized by our telecommunications investment, resulting in a $48 million increase in deferred income tax expense; and
- Telecommunications operating losses of $28 million.

Outlook

In order to deliver results to shareholders, we are focused on maintaining operational excellence, managing generation-related fuel expenses, increasing gas and oil production and managing commodity price risk. In 2006, we believe our operating businesses will provide moderate growth in net income on a per share basis, including the impact of higher expected average shares outstanding.

Positive drivers include:

- Continued growth in utility customers;
- Receipt of business interruption insurance proceeds for delays in gas and oil production caused by Hurricanes Katrina and Rita;
- An increase in gas and oil production and higher realized prices for gas and oil; and
- A full year s contribution from Kewaunee.

The positive drivers will be partially offset by:

- A potential decrease in regulated electric sales, as compared to 2005, assuming our utility service territory experiences a return to normal weather in 2006;
- A decrease in gains from the sale of excess emissions allowances;
- A full year s reduction in rates charged by gas transmission operations due to a rate settlement that was effective in July 2005;
- Higher expected operating expenses for gas and oil production; and
- Increased pension and other benefits expense.

Based on these projections, we estimate that cash flow from operations will increase in 2006, as compared to 2005. We believe this increase will provide sufficient cash flow to maintain or grow our current dividend to common shareholders.

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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,	2005		2004		2003	
(millions, except EPS)	Net Income	Diluted EPS	Net Income	Diluted EPS	Net Income	Diluted EPS
Dominion Delivery	$ 448	$ 1.30	$ 466	$ 1.41	$ 453	$ 1.42
Dominion Energy	319	0.93	190	0.57	346	1.09
Dominion Generation	402	1.17	525	1.59	512	1.60
Dominion Exploration & Production	565	1.64	595	1.80	415	1.30
Primary operating segments	1,734	5.04	1,776	5.37	1,726	5.41
Corporate	(701)	(2.04)	(527)	(1.59)	(1,408)	(4.41)
Consolidated	$ 1,033	$ 3.00	$ 1,249	$ 3.78	$ 318	$ 1.00

Selected statistics for our operating segments are presented below:

Year Ended December 31,	2005	% Change	2004	% Change	2003
Dominion Delivery					
Electricity delivered (million megawatt hours)	81	3.8%	78	4.0%	75
Degree days (electric service area):					
Cooling[1]	1,707	7.7	1,585	13.8	1,393
Heating[2]	3,784	2.8	3,682	(4.7)	3,865
Electric delivery customer accounts[3]	2,309	1.9	2,267	1.8	2,227
Gas throughput (bcf):					
Gas sales	131	3.1	127	(5.2)	134
Gas transportation	241	(1.2)	244	2.1	239
Heating degree days (gas service area)[2]	5,899	3.2	5,716	(5.3)	6,035
Gas delivery customer accounts[3]:					
Gas sales	1,006	(6.2)	1,072	12.5	953
Gas transportation	692	9.8	630	(15.5)	746
Unregulated retail energy marketing customer accounts[3]	1,166	0.9	1,156	(15.2)	1,363
Dominion Energy					
Gas transportation throughput (bcf)	794	12.8	704	14.7	614
Dominion Generation					
Electricity supplied (million megawatt hours):					
Utility	81	3.8	78	4.0	75
Merchant	41	41.4	29	11.5	26
Dominion E&P					
Gas production (bcf)	280	(16.9)	337	(7.4)	364
Oil production (million bbls)	15.3	12.5	13.6	12.4	12.1
Average realized prices with hedging results[4]:					
Gas (per mcf)[5]	$ 4.73	15.9	$ 4.08	2.8	$ 3.97
Oil (per bbl)	30.21	20.3	25.11	7.7	23.32
Average prices without hedging results:					
Gas (per mcf)[5]	7.98	39.0	5.74	13.0	5.08
Oil (per bbl)	49.54	39.6	35.49	30.0	27.30
DD&A (per mcfe)	1.47	13.1	1.30	8.3	1.20
Average production (lifting) cost (per mcfe)[6]	1.17	27.2	0.92	15.0	0.80

bcf = billion cubic feet

bbl = barrel

mcf = thousand cubic feet

mcfe = thousand cubic feet equivalent

(1) Cooling degree days are the differences between the average temperature for each day and 65 degrees, assuming the average temperature is greater than 65 degrees.
(2) Heating degree days are the differences between the average temperature for each day and 65 degrees, assuming the average temperature is less than 65 degrees.
(3) In thousands, at period end.
(4) Excludes the effects of the economic hedges discussed under *Dominion Energy*.
(5) Excludes $323 million, $223 million and $43 million of revenue recognized in 2005, 2004 and 2003, respectively, under the volumetric production payment (VPP) agreements described in Note 12 to our Consolidated Financial Statements.
(6) The exclusion of volumes produced and delivered under the VPP agreements accounted for approximately 17% of the increase from 2004 to 2005 and 75% of the increase from 2003 to 2004.

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Dominion Delivery

Dominion Delivery includes our regulated electric and gas distribution and customer service business, as well as nonregulated retail energy marketing operations.

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

2005 vs. 2004

	Increase (Decrease)	
	Amount	EPS
(millions, except 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
Other	5	0.02
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.

2004 vs. 2003

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Nonregulated retail energy marketing operations[1]	$ 32	$ 0.10
Regulated electric sales:		
Customer growth	9	0.03
Weather	4	0.01
Reliability expenses[2]	(11)	(0.03)
Regulated gas sales weather	(9)	(0.03)
Other[3]	(12)	(0.04)
Share dilution		(0.05)
Change in net income contribution	$ 13	$ (0.01)

(1) Higher contribution primarily reflects an increase in average customer accounts and higher electric and gas margins.
(2) Higher reliability expenses, largely due to increased tree trimming.
(3) Other factors, including a decrease in net pension credits.

Dominion Energy

Dominion Energy includes our tariff-based electric transmission, natural gas transmission pipeline and storage businesses and an LNG facility. It also includes certain natural gas production and producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage and associated gas trading and the prior year s results of certain energy trading activities exited in December 2004.

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

2005 vs. 2004

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Producer services[1]	$ 119	$ 0.36
Economic hedges[2]	22	0.07
Cove Point[3]	13	0.04
Gas transmission rate reduction[4]	(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.
(4) Represents the impact of a comprehensive rate settlement between Dominion Transmission, Inc. (DTI) and its customers. The settlement, which became effective July 1, 2005, will reduce our natural gas transportation and storage service revenues by approximately $49 million annually.

2004 vs. 2003

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Energy trading and marketing[1]	$ (116)	$ (0.37)
Electric transmission revenue[2]	(15)	(0.05)
Economic hedges	(12)	(0.04)
Other[3]	(13)	(0.04)
Share dilution		(0.02)
Change in net income contribution	$ (156)	$ (0.52)

(1) The loss from energy trading and marketing activities reflects comparatively lower price volatility on natural gas option positions and the effect of unfavorable price changes on electric trading margins.
(2) Reflects decreased wheeling revenue resulting from lower contractual volumes and unfavorable market conditions.
(3) Other factors including losses from asset and price risk management activities related to intersegment marketing.

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Dominion Generation

Dominion Generation includes the generation operations of our electric utility and merchant fleet as well as energy marketing and risk management activities associated with the optimization of generation assets.

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

2005 vs. 2004

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Fuel expenses in excess of rate recovery	$ (280)	$ (0.85)
Interest and other financing expense[1]	(51)	(0.15)
Energy marketing and risk management activities[2]	(50)	(0.15)
Salaries, wages and benefits expense	(36)	(0.11)
Merchant generation[3]	103	0.31
Sales of excess emissions allowances	63	0.19
Energy supply margin[4]	40	0.12
Purchased electric capacity expense	37	0.11
Regulated electric sales:		
Weather	39	0.12
Customer growth	24	0.07
Other	(12)	(0.04)
Share dilution		(0.04)
Change in net income contribution	$ (123)	$ (0.42)

(1) 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.
(2) Reflects lower gains in 2005 from coal trading and marketing activities and current year losses related to risk management activities and legacy power transactions.
(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 planned outage in 2005.
(4) Higher energy supply margins reflect a benefit related to financial transmission rights realized in our utility operations.

2004 vs. 2003

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Nuclear decommissioning trust investment performance	$ 38	$ 0.12
Purchased electric capacity expense	36	0.11
Coal trading and marketing[1]	31	0.10
Regulated electric sales:		
Customer growth	20	0.06
Weather	10	0.03
Fuel expenses in excess of rate recovery	(115)	(0.36)
Other	(7)	(0.02)
Share dilution		(0.05)
Change in net income contribution	$ 13	$ (0.01)

(1) Increased contribution primarily due to higher coal prices and increased sales volumes.

Dominion E&P

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, and Western Canada.

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

2005 vs. 2004

	Increase (Decrease)	
	Amount	**EPS**
(millions, except 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 impact in 2004 of 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 Hurricanes Katrina and Rita.
(2) Reflects interruptions caused by Hurricanes Katrina and Rita 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.

2004 vs. 2003

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Gas and oil prices	$ 67	$ 0.21
Business interruption insurance Hurricane Ivan	61	0.19
Gas and oil production	40	0.13
Operations and maintenance[1]	26	0.08
DD&A[2]	(17)	(0.05)
Other	3	0.01
Share dilution		(0.07)
Change in net income contribution	$ 180	$ 0.50

(1) Lower operations and maintenance expenses, primarily due to favorable changes in the fair value of certain oil options, partially offset by an increase in production costs.
(2) Higher depreciation, depletion and amortization, primarily reflecting higher industry finding and development costs and increased acquisition costs.

Included below are the volumes and weighted average prices associated with economic hedges in place as of December 31, 2005 by applicable time period. Prior cash flow hedges for which hedge accounting was discontinued due to production interruptions caused by Hurricanes Katrina and Rita, and for which amounts were reclassified from AOCI to earnings upon the discontinuance of hedge accounting, are excluded from the following table:

		Natural Gas		**Oil**
	Hedged production (bcf)	**Average hedge price (per mcf)**	**Hedged production (million bbls)**	**Average hedge price (per bbl)**
Year				
2006	219.8	$ 4.72	12.7	$ 25.25

2007	202.2	5.60	10.0	33.41
2008	54.0	6.49	5.0	49.36

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Corporate

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

(millions, except EPS amounts)	2005	2004	2003
Specific items attributable to operating segments	$ (505)	$(224)	$(220)
DCI operations	(22)	(82)	(96)
Telecommunications operations[1]	5	(13)	(750)
Other corporate operations	(179)	(208)	(342)
Total net expense	(701)	(527)	(1,408)
Earnings per share impact	$(2.04)	$(1.59)	$(4.41)

(1) $5 million, $(15) million and $(642) million are classified as discontinued operations in 2005, 2004 and 2003, respectively.

Specific Items Attributable to Operating Segments 2005

We reported expenses of $505 million in the Corporate segment attributable to our operating segments. The expenses in 2005 primarily related to the impact of the following:

- A $556 million loss ($357 million after-tax), 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, and subsequent changes in the fair value of those hedges, attributable to Dominion E&P;
- A $77 million ($47 million after-tax) charge resulting from the termination of a long-term power purchase agreement, attributable to Dominion Generation; and
- A $51 million charge related to credit exposure associated with the bankruptcy of Calpine Corporation, attributable to Dominion Generation. We have not recognized any deferred tax benefits related to the charge, since realization of tax benefits is not anticipated at this time based on our expected future tax profile.

Specific Items Attributable to Operating Segments 2004

We reported net expenses of $224 million in the Corporate segment attributable to our operating segments. The net expenses in 2004 primarily related to the impact of the following:

- A $184 million charge ($112 million after-tax) related to the sale of our interest in a long-term power tolling contract, attributable to Dominion Generation;
- $96 million of losses ($61 million after-tax) 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, attributable to Dominion E&P; and
- $71 million of charges ($43 million after-tax) resulting from the termination of certain long-term power purchase contracts, attributable to Dominion Generation.

Specific Items Attributable to Operating Segments 2003

We reported net expenses of $220 million in the Corporate segment attributable to our operating segments. The net expenses in 2003 primarily related to the impact of the following:

- $21 million net after-tax benefit representing the cumulative effect of adopting new accounting principles, as described in Note 3 to our Consolidated Financial Statements, including:
  - SFAS No. 143, *Accounting for Asset Retirement Obligations:* a $180 million after-tax benefit attributable to: Dominion Generation ($188 million after-tax benefit); Dominion E&P ($7 million after-tax charge); and Dominion Delivery ($1 million after-tax charge);
  - Emerging Issues Task Force (EITF) Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities:* a $67 million after-tax charge attributable to Dominion Energy;
  - 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:* a $75 million after-tax charge attributable to Dominion Generation; and

- FIN 46R: a $17 million after-tax charge attributable to Dominion Generation;

- $197 million of operations and maintenance expense ($122 million after-tax), representing incremental restoration expenses associated with Hurricane Isabel, attributable primarily to Dominion Delivery;
- A $105 million charge ($65 million after-tax) for the termination of power purchase agreements attributable to Dominion Generation;
- A $64 million charge ($39 million after-tax) for the restructuring and termination of certain electric sales agreements attributable to Dominion Generation; and
- $26 million of severance costs ($15 million after-tax) for workforce reductions during the first quarter of 2003, attributable to:
  - Dominion Generation ($8 million after-tax);
  - Dominion Energy ($2 million after-tax);
  - Dominion Delivery ($4 million after-tax); and
  - Dominion E&P ($1 million after-tax).

DCI Operations

DCI s net loss for 2005 decreased $60 million, primarily due to a reduction in after-tax charges associated with the impairment and divestiture of DCI investments.

DCI recognized a net loss of $82 million in 2004; a decrease of $14 million as compared to 2003. The decrease primarily resulted from a $20 million reduction in after-tax charges associated with asset impairments.

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.

The loss from our discontinued telecommunications business decreased $737 million to $13 million in 2004, primarily due to the impact of certain charges recognized during 2003, which included:

- $566 million associated with the impairment of network assets and related inventories. We have not recognized any deferred tax benefits related to the impairment charges, since realization of tax benefits will be dependent on our expected future tax profile;
- A $48 million increase in deferred tax expense as a result of an increase in the valuation allowance on deferred tax assets;
- Our purchase of the remaining equity interest in DFV held by another party for $62 million in December 2003, $60 million of which was recorded as goodwill and impaired;
- $57 million ($35 million after-tax) for the costs associated with our acquisition of DFV senior notes; and
- $41 million of after-tax operating losses.

Other Corporate Operations

The net expenses associated with other corporate operations for 2005 decreased by $29 million as compared to 2004, primarily

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reflecting an increase in interest income from affiliate advances and higher income tax benefits. This was partially offset by the impact in 2004 of a $28 million after-tax benefit associated with the disposition of CNGI s investment in Australian pipeline assets.

The net expenses associated with other corporate operations for 2004 decreased by $134 million as compared to 2003, predominantly due to a $28 million after-tax benefit associated with the sale of CNGI s investment in Australian pipeline assets in 2004, lower interest expense and the impact in 2003 of the following charges:

- A $22 million ($14 million after-tax) impairment related to CNGI s generation assets that were sold in December 2003;
- A $62 million ($55 million after-tax) impairment of CNGI s investment in Australian pipeline assets that were held for sale; and
- A $16 million ($10 million after-tax) loss representing the cumulative effect of adopting FIN 46R.

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 2005 follows:

(millions)	Amount
Net unrealized gain at December 31, 2004	$ 146
Contracts realized or otherwise settled during the period	(106)
Net unrealized gain at inception of contracts initiated during the period	
Changes in valuation techniques	
Redefinition of trading contracts[1]	2
Other changes in fair value	(49)
Net unrealized loss at December 31, 2005	$ (7)

(1) Represents the designation of certain commodity derivative contracts as non-trading that were previously held for trading purposes as discussed in Note 28 to our Consolidated Financial Statements.

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at December 31, 2005, 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]	$ 14	$ (7)	$ (10)	$ 2		$ (1)
Other external sources[2]		(4)		(1)	$ (1)	(6)

Models and other valuation methods						
Total	$ 14	$ (11)	$ (10)	$ 1	$ (1)	$ (7)

(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.

Sources and Uses of Cash

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, 2005, we had cash and cash equivalents of $146 million and $2.0 billion of unused capacity under our credit facilities.

Operating Cash Flows

As presented on our Consolidated Statements of Cash Flows, net cash flows from operating activities were $2.6 billion, $2.8 billion and $2.4 billion for the years ended December 31, 2005, 2004 and 2003, respectively. 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. 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.

Our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flow, including:

- Cost-recovery shortfalls due to capped base rates and fixed fuel recovery provisions in effect in Virginia for our generation operations ;
- The collection of business interruption insurance proceeds associated with the recovery of delayed gas and oil production due to Hurricanes Katrina and Rita;
- Unusual weather and its effect on energy sales to customers and energy commodity prices;
- Extreme weather events that could disrupt gas and oil production or cause catastrophic damage to our electric distribution and transmission systems;
- Exposure to unanticipated changes in prices for energy commodities purchased or sold, including the effect on derivative instruments that may require the use of funds to post collateral with counterparties;
- Effectiveness of our risk management activities and underlying assessment of market conditions and related factors, including energy commodity prices, basis, liquidity, volatility, counterparty credit risk, availability of generation and transmission capacity, currency exchange rates and interest rates;

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- The cost of replacement electric energy in the event of longer-than-expected or unscheduled generation outages;
- Contractual or regulatory restrictions on transfers of funds among Dominion and our subsidiaries; and
- Timeliness of recovery for costs subject to cost-of-service utility rate regulation.

Credit Risk

Exposure to potential concentrations of credit risk results primarily from our energy marketing and risk management activities and sales of gas and oil production. Presented below is a summary of our gross and net credit exposure as of December 31, 2005 for these activities. We calculate our gross credit exposure for each counterparty as the unrealized fair value of derivative contracts plus any outstanding receivables (net of payables, where netting agreements exist), prior to the application of collateral.

(millions)	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
Investment grade[1]	$ 931	$ 143	$ 788
Non-investment grade[2]	26		26
No external ratings:			
Internally rated investment grade[3]	46		46
Internally rated non-investment grade[4]	343		343
Total	$ 1,346	$ 143	$ 1,203

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody s Investors Service (Moody s) and Standard & Poor s Rating Group, a division of the McGraw-Hill Companies, Inc. (Standard & Poor s). The five largest counterparty exposures, combined, for this category represented approximately 19% 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 4% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 7% of the total net credit exposure.

Investing Cash Flows

During 2005, 2004 and 2003, investing activities resulted in net cash outflows of $3.4 billion, $1.2 billion, and $3.4 billion respectively. Significant investing activities for 2005 included:

- $1.7 billion of capital expenditures for the construction and expansion of generation facilities, environmental upgrades, purchase of nuclear fuel, construction and improvements of gas and electric transmission and distribution assets and the cost of acquiring a nonutility generating facility;
- $1.7 billion of capital expenditures for the purchase and development of gas and oil producing properties, drilling and equipment costs and undeveloped lease acquisitions;
- $877 million primarily related to the acquisition of the Dominion New England power plants and the Kewaunee power station; and
- $854 million for the purchase of securities; partially offset by
- $754 million of proceeds from the sale of securities;
- $595 million of proceeds from sales of gas and oil mineral rights and properties; and
- $234 million of proceeds from sales of excess emissions allowances.

Financing Cash Flows and Liquidity

We rely on banks and capital markets as significant sources of funding for capital requirements not satisfied by cash provided by the companies operations. As discussed further in the *Credit Ratings* section below, 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 them to use an automatic shelf registration statement to register any offering of securities, other than those for business combination transactions.

During 2005 and 2003, net cash flows from financing activities were $522 million and $853 million, respectively. During 2004 net cash used in financing activities was $1.3 billion. Significant financing activities in 2005 included:

- $2.3 billion from the issuance of long-term debt;
- $1.0 billion from the net issuance of short-term debt;
- $664 million from the issuance of common stock; partially offset by
- $2.2 billion for the repayment of long-term debt;
- $923 million of common dividend payments; and
- $276 million for the repurchase 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. In May 2005, we entered into a $2.5 billion five-year revolving credit facility that replaced our $1.5 billion three-year facility dated May 2004 and our $750 million three-year facility dated May 2002. In August 2005, CNG entered into a $1.75 billion five-year facility that replaced its $1.5 billion three-year facility dated August 2004. At December 31, 2005, we had committed lines of credit totaling $4.25 billion. Although there were no loans outstanding, these lines of credit support commercial paper borrowings and letter of credit issuances. At December 31, 2005, we had the following commercial paper and letters of credit outstanding and capacity available under credit facilities:

(millions)	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
Five-year revolving credit facility[1]	$ 2,500	$ 1,401	$ 892	$ 207
Five-year CNG credit facility[2]	1,750	187	1,227	336
Totals	$ 4,250	$ 1,588	$ 2,119	$ 543

(1) The $2.5 billion five-year credit facility was entered into in May 2005 and terminates in May 2010. This credit facility can also be used to support up to $1.25 billion of letters of credit. In February 2006, this facility was replaced by a $3.0 billion five-year credit facility that terminates in February 2011.

(2) The $1.75 billion five-year credit facility is 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 August 2005 and terminates in August 2010. In February 2006, the facility limit was reduced to $1.70 billion.

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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 merchant generation and gas and oil production operations, respectively. Collateral requirements have increased significantly in 2005 as a result of escalating commodity prices. At December 31, 2005, 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	$ 100	$	June 2004	June 2007
CNG	100	100		August 2004	August 2009
CNG(1)	550	550		October 2004	April 2006
CNG(2)	1,900	625	1,275	August 2005	February 2006
CNG(3)	200		200	December 2005	December 2010
Dominion Resources, Inc.	150	150		September 2005	March 2006
Dominion Resources, Inc.	200	200		August 2005	February 2006
Dominion Resources, Inc.(4)	290	290		October 2005	April 2006
	$ 3,490	$ 2,015	$1,475		

(1) In February 2006, the facility limit was reduced to $150 million.
(2) In February 2006, CNG replaced this facility with a $1.05 billion 364-day credit facility.
(3) This facility can also be used to support commercial paper borrowings.
(4) In February 2006, the facility limit was reduced to $215 million.

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.

Our financial policy precludes issuing commercial paper in excess of our supporting lines of credit. At December 31, 2005, the total amount of commercial paper outstanding was $1.6 billion and the total amount of letter of credit issuances was $4.1 billion, leaving approximately $2.0 billion available for issuance. We are required to pay minimal annual commitment fees to maintain the credit facilities.

In addition, these 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, material adverse change clauses and cross-default provisions.

All of the credit facilities include a defined maximum total debt to total capital ratio. As of December 31, 2005, the calculated ratio for our companies, pursuant to the terms of the agreements, was as follows:

Company	Maximum Ratio	Actual Ratio(1)
Dominion Resources, Inc.	65%	59%
Virginia Power	65%	46%
CNG	65%	55%

(1) Indebtedness as defined by the bank agreements excludes certain junior subordinated notes payable to affiliated trusts and mandatorily convertible securities that are reflected as long-term debt on our Consolidated Balance Sheets.

These provisions apply separately to Dominion Resources, Inc., Virginia Power and CNG (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 $25 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. However, any default by either CNG or Virginia Power would also affect in like manner the lenders commitment to Dominion Resources, Inc. under the joint credit agreements.

Although the joint credit agreements contain material adverse change clauses, the participating lenders, under those specific provisions, cannot refuse to advance funds to any of the Dominion Companies for the repurchase of our outstanding commercial paper.

Long-Term Debt

During 2005, Dominion Resources, Inc. issued the following long-term debt:

Type	Principal (millions)	Rate	Maturity
Senior notes	$1,000	variable	2007
Senior notes	300	4.75%	2010
Senior notes	500	5.15%	2015
Senior notes	500	5.95%	2035
Total long-term debt issued	$2,300		

In February 2005, in connection with the acquisition of a nonutility generating facility from Panda-Rosemary LP (Rosemary), Virginia Power assumed $62 million of Rosemary s 8.625% senior notes that mature in 2016. In addition, in February and April of 2005, Virginia Power issued $2 million and $6 million, respectively, of 7.25% promissory notes, which mature in 2025 and 2032, respectively, in exchange for electric distribution facilities at certain military bases in connection with their privatization.

In January 2006, Virginia Power issued $450 million of 5.4% senior notes that mature in 2016 and $550 million of 6.0% senior notes that mature in 2036.

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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%, in order to finance certain improvements to our Brayton Point Station located in Somerset, Massachusetts.

During 2005, we repaid $2.2 billion of long-term debt securities.

Issuance of Common Stock

During 2005, we received proceeds of $345 million for 5.8 million shares issued through Dominion Direct® (a dividend reinvestment and open enrollment direct stock purchase plan), employee savings plans and the exercise of employee stock options. In February 2005, Dominion Direct® and the Dominion employee savings plans began purchasing Dominion 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. During 2005, we repurchased 3.7 million shares for approximately $276 million.

Forward Equity Transaction

In September 2004, we entered into a forward equity sale agreement (forward agreement) with Merrill Lynch International (MLI), as forward purchaser, relating to 10 million shares of our common stock. The forward agreement provided for the sale of two tranches of our common stock, each with stated maturity dates and settlement prices. In connection with the forward agreement, MLI borrowed an equal number of shares of our common stock from stock lenders and, at our request, sold the borrowed shares to J.P. Morgan Securities Inc. (JPM) under a purchase agreement among Dominion, MLI and JPM. JPM subsequently offered the borrowed shares to the public. We accounted for the forward agreement as equity at its initial fair value but did not receive any proceeds from the sale of the borrowed shares.

The use of a forward agreement allowed us to avoid equity market uncertainty by pricing a stock offering under then existing market conditions, while mitigating share dilution by postponing the issuance of stock until funds were needed. Except in specified circumstances or events that would have required physical share settlement, we were able to elect to settle the forward agreement by means of a physical share, cash or net share settlement and were also able to elect to settle the agreement in whole, or in part, earlier than the stated maturity date at fixed settlement prices. Under either a physical share or net share settlement, the maximum number of shares that were deliverable under the terms of the forward agreement was limited to the 10 million shares specified in the two tranches. Assuming gross share settlement of all shares under the forward agreement, we would have received aggregate proceeds of approximately $644 million, based on maturity forward prices of $64.62 per share for the 2 million shares included in the first tranche and $64.34 per share for the 8 million shares included in the second tranche.

We elected to cash settle the first tranche in December 2004 and paid MLI $5.8 million, representing the difference between our share price and the applicable forward sale price, multiplied by the 2 million shares. Additionally, we elected to cash settle 3 million shares of the second tranche in February 2005 and paid MLI $17.4 million. We recorded the settlement payments as a reduction to common stock in our Consolidated Balance Sheets.

In April 2005, we entered into an agreement with MLI that extended the settlement date for the remaining 5 million shares of the second tranche to August 2005. In August 2005, we delivered 5 million newly issued shares of our common stock to MLI, and received proceeds of $319.7 million as final settlement of the forward agreement.

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 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.

Credit ratings for the Dominion Companies as of February 1, 2006 follow:

	Fitch	Moody s	Standard & Poor s
Dominion Resources, Inc.			
Senior unsecured debt securities	BBB+	Baa1	BBB
Preferred securities of affiliated trusts	BBB	Baa2	BB+
Commercial paper	F2	P-2	A-2
Virginia Power			
Mortgage bonds	A	A2	A-
Senior unsecured (including tax-exempt) debt securities	BBB+	A3	BBB
Preferred securities of affiliated trust	BBB	Baa1	BB+
Preferred stock	BBB	Baa2	BB+
Commercial paper	F2	P-1	A-2
CNG			
Senior unsecured debt securities	BBB+	A3	BBB
Preferred securities of affiliated trust	BBB	Baa1	BB+
Commercial paper	F2	P-2	A-2

These credit ratings reflect Standard & Poor s December 2005 downgrade of its credit ratings for the Dominion Companies senior unsecured debt securities. Standard & Poor s concluded that fuel expenses in excess of rate recovery at Virginia Power and delays in gas and oil production at CNG have caused a deterioration in Dominion s financial performance to a level more commensurate with a BBB rating and that there will be no material improvement in Dominion s credit profile before midyear 2007. In January 2006, Moody s announced that it had placed the credit ratings of the Dominion Companies under review for possible downgrade, citing recent financial performance that was weaker than expected, a decline in funds from operations and higher than expected leverage. Moody s review is expected to be completed within three months and will focus on the Dominion

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Companies expected financial profile over the next 12-18 months. As of February 1, 2006, Fitch Ratings Ltd. (Fitch) and Standard & Poor s maintain a stable outlook for their ratings of the Dominion Companies.

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 substantial assets;
- Compliance with collateral minimums or requirements related to mortgage bonds; and
- Limitations on liens.

We monitor the covenants on a regular basis in order to ensure that events of default will not occur. As of December 31, 2005, there were no events of default under the Dominion Companies covenants.

Dividend Restrictions

The Public Utility Holding Company Act of 1935 (1935 Act) and related regulations issued by the SEC impose restrictions on the transfer and receipt of funds by a registered holding company from its subsidiaries, including a general prohibition against loans or advances being made by the subsidiaries to benefit the registered holding company. Under the 1935 Act, registered holding companies and their subsidiaries may pay dividends only from retained earnings, unless the SEC specifically authorizes payments from other capital accounts. Our ability to pay dividends on our common stock at declared rates was not impacted by these restrictions during 2005, 2004 and 2003. We will not be bound by the foregoing restrictions on dividends imposed by the 1935 Act after February 8, 2006, the effective date on which the 1935 Act was repealed under the Energy Policy Act of 2005.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

We are party to numerous contracts and arrangements obligating us to make cash payments in future years. These contracts include financing arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services 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, 2005. 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 on 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 2006.

	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total

(millions)					
Long-term debt[1]	$ 2,330	$ 3,661	$ 1,900	$ 9,179	$ 17,070
Interest payments[2]	1,004	1,557	1,294	7,056	10,911
Leases	131	284	238	345	998
Purchase obligations[3]:					
Purchased electric capacity for utility operations	441	805	718	2,536	4,500
Fuel to be used for utility operations	772	819	501	640	2,732
Fuel to be used for nonregulated operations	256	44	17		317
Production handling	54	87	36	13	190
Pipeline transportation and storage	92	145	106	93	436
Energy commodity purchases for resale[4]	1,076	283	9	1	1,369
Other	316	198	40	15	569
Other long-term liabilities[5]:					
Financial derivative commodities[4]	2,566	2,070	2		4,638
Other contractual obligations[6]	74	103	49	32	258
Total cash payments	$ 9,112	$ 10,056	$ 4,910	$ 19,910	$ 43,988

(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 distributions related to our junior subordinated notes payable to affiliated trusts.
(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 us were liquidated and terminated.
(5) 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.
(6) Includes interest rate swap agreements.

Our planned capital expenditures during 2006 and 2007 are expected to total approximately $3.8 billion and $3.9 billion, respectively. These expenditures are expected to include construction and expansion of 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.

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

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Use of Off-Balance Sheet Arrangements

Forward Equity Transaction

As described in *Financing Cash Flows and Liquidity Forward Equity Transaction*, in September 2004 we entered into a forward equity sale agreement relating to 10 million shares of our common stock. The use of a forward agreement allowed us to avoid equity market uncertainty by pricing a stock offering under then current market conditions, while mitigating share dilution by postponing the issuance of stock until funds were needed.

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, 2005, we have issued $37 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 exploration and production 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 view this scenario as highly unlikely and have not recognized any significant liabilities related to any of these arrangements.

Leasing Arrangement

We have an agreement with a voting interest entity (lessor) 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 on 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.

Securitizations of Mortgages and Loans

As of December 31, 2005, we held $285 million of retained interests from securitizations of mortgage and commercial loans completed in prior years. We did not securitize or originate any loans in 2005 or 2004. Investors in the securitization trusts have no recourse to our other assets for failure of debtors to repay principal and interest on the underlying loans when due. Therefore, our exposure to any future losses from this activity is limited to our investment in the retained interests.

Future Issues and Other Matters

Gas and Oil Production

Due to Hurricanes Katrina and Rita, our production assets in the Gulf of Mexico and, to a lesser extent, South Louisiana were temporarily shut in. Prior to the hurricanes, these assets were producing approximately 435 million cubic feet of natural gas equivalent per day (mmcfed). We had forecasted production increases to approximately 700 mmcfed during October with the addition of four previously announced deepwater projects, plus other planned completion activity. As of mid-January 2006, our Gulf of Mexico and South Louisiana assets were producing approximately 500 mmcfed, however 330 mmcfed of this production was accomplished via temporary measures. The production delays are primarily the result of damage to third-party downstream facilities. The majority of the third-party downstream facilities are projected to become operational by the second quarter of 2006, with the remainder estimated to be on stream by year-end. We expect that the financial impacts of delays in production will be mitigated by business interruption insurance that we maintain for hurricane-related delays in natural gas and oil production. Our business interruption insurance covers delays caused both by damage to our own production facilities and by damage to third-party facilities downstream. Our policy coverage for Hurricane Katrina has a 30-day deductible period and an event limit of $700 million, while our policy for Hurricane Rita has a 45-day deductible period and an event limit of $350 million.

Status of Electric Deregulation in Virginia

The Virginia Electric Utility Restructuring Act (Virginia Restructuring Act) was enacted in 1999 and established a plan to restructure the electric utility industry in Virginia. The Virginia Restructuring Act addressed, among other things: capped base rates, RTO participation, retail choice, the recovery of stranded costs, and the functional separation of a utility s electric generation from its electric transmission and distribution operations.

Retail choice has been available to all of our Virginia regulated electric customers since January 1, 2003. We have also separated our generation, distribution and transmission functions through the creation of divisions. State regulatory requirements ensure that our generation and other divisions operate independently and prevent cross-subsidies between generation and other divisions.

In 2004, the Virginia Restructuring Act and the Virginia fuel factor statute were amended. The amendments extend capped base rates to December 31, 2010, unless modified or terminated earlier under the Virginia Restructuring Act. The amendments also:

- Lock in our fuel factor provisions until the earlier of July 1, 2007 or the termination of capped rates under the Virginia Restructuring Act, with no adjustment for previously incurred over-recovery or under-recovery of fuel costs, thus eliminating deferred fuel accounting for the Virginia jurisdiction;
- Provide for a one-time adjustment of our fuel factor, effective July 1, 2007 through December 31, 2010 (unless capped

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rates are terminated earlier under the Virginia Restructuring Act), with no adjustment for previously incurred over-recovery or under-recovery of fuel costs; and
- End wires charges on the earlier of July 1, 2007, or the termination of capped rates.

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen, 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.

When our fuel factor is adjusted in July 2007, we will remain subject to the risk that fuel factor-related cost recovery shortfalls may adversely affect our margins. Conversely, we could experience a positive economic impact to the extent that we can reduce our fuel factor-related costs for our electric utility generation-related operations.

We anticipate that our unhedged natural gas and oil production will act as a natural internal hedge for fuel used in electric generation. If gas and oil prices rise, it is expected that our exploration and production operations will earn greater profits that will help mitigate higher fuel costs and lower profits in our electric utility generation operations. Conversely, if gas and oil prices fall, it is expected that our electric utility generation operations will incur lower fuel costs and earn higher profits that will help mitigate lower profits in our exploration and production operations. We also anticipate that the fixed fuel rate will lessen the impact of weather on our electric utility generation operations. During periods of mild weather it is expected that our electric utility generation operations will burn less high-cost fuel because customers will use less electricity, thereby mitigating decreased revenues. Alternatively, in periods of extreme weather, our higher fuel costs from running costlier plants are expected to be mitigated by additional revenues as customers use more electricity.

Other amendments to the Virginia Restructuring Act were also enacted in 2004 with respect to a minimum stay exemption program, a wires charge exemption program and the development of a coal-fired generating plant in southwest Virginia for serving default service needs. Under the minimum stay exemption program, large customers with a load of 500 kilowatts or greater would be exempt from the twelve-month minimum stay obligation under capped rates if they return to supply service from the incumbent utility at market-based pricing after they have switched to supply service with a competitive service provider. The wires charge exemption program would allow large industrial and commercial customers, as well as aggregated customers in all rate classes, to avoid paying wires charges when selecting electricity supply service from a competitive service provider by agreeing to market-based pricing upon return to the incumbent utility. For 2006, our wires charges are set at zero for all rate classes. In February 2005, we joined a consortium to explore the development of a coal-fired electric power station in southwest Virginia.

Stranded costs are generation-related costs incurred or commitments made by utilities under cost-based regulation that may not reasonably be expected to be recovered in a competitive market. At December 31, 2005, our exposure to potential stranded costs included long-term power purchase contracts that could ultimately be determined to be above market; generating plants that could possibly become uneconomical in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits not yet recognized in the financial statements. 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 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 Virginia Restructuring Act are intended to compensate us for continuing to provide generation services and to allow us to incur costs to restructure our 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 investment in our business.

Ohio Energy Choice Pilot Program

In April 2005, we filed with the Public Utilities Commission of Ohio (Ohio Commission) a proposal for a two-year pilot program to improve and expand our Energy Choice Program. Under the current structure, non-Energy Choice customers purchase gas directly from us at a monthly gas cost recovery, or GCR, rate that includes true-up adjustments that can change significantly from one quarter to the next. We propose to replace the GCR with a monthly market price that eliminates those adjustments, making it easier for customers to compare and switch to competitive suppliers. A ruling on this proposal is expected by the end of the first quarter of 2006. By the end of the transition period, and 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 remain the provider of last resort in the event of default by a supplier.

Energy Policy Act of 2005 (EPACT)

In August 2005, the President of the United States signed EPACT. Key provisions of the Act include the following:

- Repeal of the 1935 Act in February 2006;
- Establishment of a self-regulating electric reliability organization governed by an independent board with FERC oversight;
- Provision for greater regulatory oversight by other federal and state authorities;
- Extension of the Price Anderson Act for 20 years until 2025;
- Provision for standby financial support and production tax credits for new nuclear plants;
- Grant of enhanced merger approval authority to FERC;
- Provision of authority to FERC for the siting of certain electric transmission facilities if states cannot or will not act in a timely manner;
- Grant of exclusive authority to FERC to approve applications for construction of LNG facilities; and
- Improvement of the process for approval and permitting of interstate pipelines.

Many of the changes Congress enacted must be implemented through public notice and proposed rule making by the federal agencies affected and this process is ongoing. We will continue to evaluate the effects that EPACT may have on our business.

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Common Stock Dividend Increase

In February 2005, our quarterly dividend rate increased from 66.5 cents per share to 67 cents per share for an annual rate in 2005 of $2.68 per share. Our quarterly dividend rate increased again in January 2006, from 67 cents per share to 69 cents per share for an annual rate in 2006 of $2.76. Our expected cash flow and earnings should enable us to make future annual 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. Historically, we recovered such costs arising from regulated electric operations through utility rates. However, to the extent that environmental costs are incurred in connection with operations regulated by the Virginia Commission, during the period ending 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.

Environmental Protection and Monitoring Expenditures

We incurred approximately $205 million, $132 million and $113 million of expenses (including depreciation) during 2005, 2004 and 2003, respectively, in connection with environmental protection and monitoring activities and expect these expenses to be approximately $201 million and $202 million in 2006 and 2007, respectively. In addition, capital expenditures related to environmental controls were $140 million, $94 million and $210 million for 2005, 2004 and 2003, respectively. These expenditures are expected to be approximately $307 million and $278 million for 2006 and 2007, respectively.

Clean Air Act Compliance

We are required by the Clean Air Act (the Act) to reduce air emissions of various air pollutants that are the by-products of fossil fuel combustion. The Act s new Clean Air Interstate Rule and Clean Air Mercury Rule will require significant reductions in future SO_2, NO_X and mercury emissions from our electric generating facilities and will require capital expenditures. The Act s existing SO_2 and NO_X reduction programs already include:

- The issuance of a limited number of SO_2 emissions allowances. Each allowance permits the emission of one ton of SO_2 into the atmosphere;
- NO_X emission limitations applicable during the ozone season months of May through September and on an annual average basis; and
- SO_2 and NO_X allowances may be transacted with a third party.

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 allowances and emission control technology. In response to these requirements, we estimate that we will make capital expenditures at our affected generating facilities of approximately $1.1 billion during the period 2006 through 2010.

Other

As part of its review of our request related to the reissuance of a pollution discharge elimination permit for the Millstone Power Station, the Connecticut Department of Environmental Protection is evaluating the ecological impacts of the cooling water intake system. Until the permit is reissued, it is not possible to predict the financial impact that may result.

In October 2003, the Environmental Protection Agency (EPA) and the Massachusetts Department of Environmental Protection (DEP) each issued new National Pollutant Discharge Elimination System 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 Environmental Appeals Board (EAB) and the Division of Administrative Law Appeals in Massachusetts, and both permits were stayed. In February 2006 the EAB remanded a portion of EPA s permit to EPA for reconsideration. The DEP permit is still stayed pending the outcome of the EPA process. Until the remand and any resulting appeals are completed, the outcome cannot be predicted.

Future Environmental Regulations

The U.S. Congress is considering 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 a variety of periods of up to 15 years. If these new proposals are adopted, additional significant expenditures may be required.

In 1997, the United States signed an international Protocol to limit man-made greenhouse emissions under the United Nations Framework Convention on Climate Change. However, the Protocol will not become binding unless approved by the U.S. Senate. Currently, the Bush Administration has indicated that it will not pursue ratification of the Protocol and has set a voluntary goal of reducing the nation s greenhouse gas emission intensity by 18% over the period 2002-2012. Several legislative proposals that include provisions seeking to impose mandatory reductions of greenhouse gas emissions are under consideration in the United States Congress. The cost of compliance with the Protocol or other mandatory greenhouse gas reduction obligations could be significant. Given the highly uncertain outcome and timing of future action, if any, by the U.S. federal government on this issue, we cannot predict the financial impact of future climate change actions on our operations at this time.

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Restructuring of Contracts with Nonutility Generator

In October 2005, we reached an agreement in principle to restructure three long-term power purchase contracts. The restructured contracts expire between 2015 and 2017 and are expected to reduce capacity and energy payments by approximately $44 million and $6 million, respectively, over the remaining term of the contracts. The transaction became effective in February 2006 and did not result in a cash outlay or charge to earnings.

Sale of Gas Distribution Subsidiaries

On March 1, 2006 we entered into an agreement with Equitable Resources, Inc. to sell two of our wholly-owned regulated gas distribution subsidiaries, The Peoples Natural Gas Company and Hope Gas, Inc., for $969.6 million plus adjustments to reflect capital expenditures and changes in working capital. We expect to complete the transaction by the first quarter of 2007, subject to state regulatory approvals in Pennsylvania and West Virginia as well as approval under the federal Hart-Scott-Rodino Act.

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, interest rates, foreign currency exchange 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 derivative commodity contracts to manage price risk exposures for these operations. Interest rate risk is generally related to our outstanding debt. We are exposed to foreign currency exchange rate risks related to our purchase of fuel services denominated in a foreign currency. In addition, we are exposed to equity price risk through various portfolios of equity securities.

As discussed in Note 28 to our Consolidated Financial Statements, we performed an evaluation of our Clearinghouse trading and marketing operations, which resulted in a decision to exit certain trading activities and instead focus on the optimization of company assets. In connection with the reorganization, certain commodity derivative contracts previously designated as held for trading purposes are now held for non-trading purposes.

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

Commodity Price Risk

As part of our strategy to market energy and to manage related risks, we hold commodity-based financial derivative instruments for trading purposes. We also 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.

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 commodity prices would have resulted in a decrease of approximately $3 million and $23 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of December 31, 2005 and 2004, respectively. 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 $691 million and $576 million as of December 31, 2005 and 2004, 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 derivative commodity instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction, such as revenue from sales.

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, 2005, a hypothetical 10% increase in market interest rates would decrease annual earnings by approximately $20 million. A hypothetical 10% increase in market interest rates, as determined at December 31, 2004, would have resulted in a decrease in annual earnings of approximately $10 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.

Foreign Currency Exchange Risk

Our Canadian natural gas and oil exploration and production 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 State -

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ments. 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% unfavorable change in relevant foreign exchange rates would have resulted in a decrease of approximately $8 million and $13 million in the fair value of currency forward contracts held at December 31, 2005 and 2004, respectively.

Investment Price Risk

We are subject to investment price risk due to marketable securities held as investments in decommissioning trust funds. These marketable securities are reported on our Consolidated Balance Sheets at fair value. We recognized net realized gains (net of investment income) on nuclear decommissioning trust investments of $67 million in 2005 and $51 million in 2004. We recorded, in AOCI, net unrealized gains on decommissioning trust investments of $27 million and $84 million in 2005 and 2004, respectively.

We also sponsor employee pension and other postretirement benefit plans that hold investments in trusts to fund benefit payments. To the extent that the values of investments held in these trusts decline, the effect will be reflected in our recognition of the periodic cost of such employee benefit plans and the determination of the amount of cash to be contributed to the employee benefit plans. Our pension plans experienced net realized and unrealized gains of $433 million and $453 million in 2005 and 2004, respectively.

Risk Management Policies

We have operating procedures in place that are administered by experienced management to help 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, 2005 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 Shareholders and Board of Directors of

Dominion Resources, Inc.

We have audited the accompanying consolidated balance sheets of Dominion Resources, Inc. and subsidiaries (the Company) as of December 31, 2005 and 2004, 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, 2005. 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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: conditional asset retirement obligations in 2005 and asset retirement obligations, contracts involved in energy trading, derivative contracts not held for trading purposes, derivative contracts with a price adjustment feature, and the consolidation of variable interest entities in 2003.

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, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2006, expressed 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

March 1, 2006

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Consolidated Statements of Income

Year Ended December 31, (millions, except per share amounts)	2005	2004	2003
Operating Revenue	**$ 18,041**	$ 13,991	$ 12,095
Operating Expenses			
Electric fuel and energy purchases	**4,713**	2,162	1,667
Purchased electric capacity	**505**	587	607
Purchased gas	**3,941**	2,927	2,175
Other energy-related commodity purchases	**1,391**	989	446
Other operations and maintenance	**3,058**	2,766	2,947
Depreciation, depletion and amortization	**1,412**	1,305	1,216
Other taxes	**582**	519	476
Total operating expenses	**15,602**	11,255	9,534
Income from operations	**2,439**	2,736	2,561
Other income (loss)	**168**	167	(40)
Interest and related charges:			
Interest expense	**869**	811	849
Interest expense junior subordinated notes payable to affiliated trusts	**106**	112	
Distributions mandatorily redeemable trust preferred securities			111
Subsidiary preferred dividends	**16**	16	15
Total interest and related charges	**991**	939	975
Income from continuing operations before income tax expense	**1,616**	1,964	1,546
Income tax expense	**582**	700	597
Income from continuing operations before cumulative effect of changes in accounting principles	**1,034**	1,264	949
Income (loss) from discontinued operations (net of income tax expense of $3, benefit of $4 and expense of $15 in 2005, 2004 and 2003, respectively)	**5**	(15)	(642)
Cumulative effect of changes in accounting principles (net of income tax benefit of $4 and expense of $7 in 2005 and 2003, respectively)	**(6)**		11
Net Income	**$ 1,033**	$ 1,249	$ 318
Earnings Per Common Share Basic:			
Income from continuing operations before cumulative effect of changes in accounting principles	**$ 3.02**	$ 3.84	$ 2.99
Income (loss) from discontinued operations	**0.02**	(0.04)	(2.02)
Cumulative effect of changes in accounting principles	**(0.02)**		0.03
Net income	**$ 3.02**	$ 3.80	$ 1.00
Earnings Per Common Share Diluted:			
Income from continuing operations before cumulative effect of changes in accounting principles	**$ 3.00**	$ 3.82	$ 2.98
Income (loss) from discontinued operations	**0.02**	(0.04)	(2.01)
Cumulative effect of changes in accounting principles	**(0.02)**		0.03
Net income	**$ 3.00**	$ 3.78	$ 1.00
Dividends paid per common share	**$ 2.68**	$ 2.60	$ 2.58

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

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Consolidated Balance Sheets

At December 31, (millions)	2005	2004
ASSETS		
Current Assets		
Cash and cash equivalents	$ 146	$ 361
Accounts receivable:		
Customers (less allowance for doubtful accounts of $38 and $43)	3,335	2,585
Other (less allowance for doubtful accounts of $9 and $17)	226	320
Inventories:		
Materials and supplies	392	328
Fossil fuel	314	180
Gas stored	461	385
Derivative assets	3,429	1,713
Deferred income taxes	928	594
Prepayments	161	157
Other	737	471
Total current assets	10,129	7,094
Investments		
Nuclear decommissioning trust funds	2,534	2,023
Available-for-sale securities	287	335
Other	680	810
Total investments	3,501	3,168
Property, Plant and Equipment		
Property, plant and equipment	42,063	38,663
Accumulated depreciation, depletion and amortization	(13,123)	(11,947)
Total property, plant and equipment, net	28,940	26,716
Deferred Charges and Other Assets		
Goodwill	4,298	4,298
Prepaid pension cost	1,915	1,947
Derivative assets	1,915	705
Regulatory assets	758	788
Other	1,204	702
Total deferred charges and other assets	10,090	8,440
Total assets	$52,660	$45,418

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At December 31, (millions)	2005	2004
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Securities due within one year	$ 2,330	$ 1,368
Short-term debt	1,618	573
Accounts payable	2,756	1,956
Accrued interest, payroll and taxes	694	578
Derivative liabilities	6,087	2,858
Other	995	695
Total current liabilities	14,480	8,028
Long-Term Debt		
Long-term debt	13,237	14,078
Junior subordinated notes payable to affiliated trusts	1,416	1,429
Total long-term debt	14,653	15,507
Deferred Credits and Other Liabilities		
Deferred income taxes	4,926	5,424
Deferred investment tax credits	58	75
Asset retirement obligations	2,249	1,705
Derivative liabilities	3,971	1,583
Regulatory liabilities	607	610
Other	1,062	803
Total deferred credits and other liabilities	12,873	10,200
Total liabilities	42,006	33,735
Commitments and Contingencies (see Note 23)		
Subsidiary Preferred Stock Not Subject To Mandatory Redemption	257	257
Common Shareholders Equity		
Common stock no par(1)	11,286	10,888
Other paid-in capital	125	92
Retained earnings	1,550	1,442
Accumulated other comprehensive loss	(2,564)	(996)
Total common shareholders equity	10,397	11,426
Total liabilities and shareholders equity	$ 52,660	$ 45,418

(1) 500 million shares authorized; 347 million shares and 340 million shares outstanding at December 31, 2005 and December 31, 2004, 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

(millions)	Common Stock Shares	Common Stock Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2002	308	$ 9,051	$ 47	$ 1,561	$ (446)	$ 10,213
Comprehensive income:						
Net income				318		318
Net deferred derivative losses hedging activities, net of $479 tax benefit					(791)	(791)
Unrealized gains on investment securities, net of $78 tax expense					112	112
Foreign currency translation adjustments					68	68
Amounts reclassified to net income:						
Net realized losses on investment securities, net of $29 tax benefit					49	49
Net derivative losses hedging activities, net of $225 tax benefit					379	379
Total comprehensive income				318	(183)	135
Issuance of stock public offering	11	683				683
Issuance of stock employee and direct stock purchase plans	3	206				206
Stock awards and stock options exercised (net of change in unearned compensation)	3	112				112
Tax benefit from stock awards and stock options exercised			14			14
Dividends				(825)		(825)
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)
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)
					27	27

Unrealized gains on investment securities, net of $19 tax expense						
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

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

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Consolidated Statements of Cash Flows

Year Ended December 31, (millions)	2005	2004	2003
Operating Activities			
Net income	$ 1,033	$ 1,249	$ 318
Adjustments to reconcile net income to net cash from operating activities:			
Impairment of telecommunications assets			566
Dominion Capital Inc. impairment losses	35	72	85
Impairment (recovery) of CNG International assets		(18)	84
Net realized and unrealized derivative (gains)/losses	335	(63)	50
Depreciation, depletion and amortization	1,538	1,433	1,334
Deferred income taxes and investment tax credits, net	64	554	452
Gain on sale of emissions allowances	(139)	(35)	(5)
Other adjustments to net income	180	9	22
Changes in:			
Accounts receivable	(791)	(288)	(507)
Inventories	(220)	(30)	(234)
Deferred fuel and purchased gas costs, net	(57)	89	(244)
Prepaid pension cost	31	(8)	(229)
Accounts payable	686	27	372
Accrued interest, payroll and taxes	147	(9)	42
Deferred revenue	(323)	(223)	(43)
Margin deposit assets and liabilities	124	(6)	(18)
Other operating assets and liabilities	(20)	17	305
Net cash provided by operating activities	2,623	2,770	2,350
Investing Activities			
Plant construction and other property additions	(1,683)	(1,451)	(2,138)
Additions to gas and oil properties, including acquisitions	(1,675)	(1,299)	(1,300)
Proceeds from sales of gas and oil properties	595	729	305
Acquisition of businesses	(877)		
Proceeds from sales of loans and securities	754	466	912
Purchases of securities	(854)	(490)	(777)
Proceeds from sale of emissions allowances	234	41	5
Escrow release for debt refunding			500
Purchase of Dominion Fiber Ventures senior notes			(633)
Advances to lessor for project under construction		(132)	(385)
Reimbursement from lessor for project under construction		806	
Other	146	115	143
Net cash used in investing activities	(3,360)	(1,215)	(3,368)
Financing Activities			
Issuance (repayment) of short-term debt, net	1,045	(879)	259
Issuance of long-term debt	2,300	877	3,393
Repayment of long-term debt	(2,237)	(1,283)	(2,922)
Issuance of common stock	664	839	990
Repurchase of common stock	(276)		
Common dividend payments	(923)	(861)	(825)
Other	(51)	(13)	(42)
Net cash provided by (used in) financing activities	522	(1,320)	853
Increase (decrease) in cash and cash equivalents	(215)	235	(165)
Cash and cash equivalents at beginning of year	361	126	291
Cash and cash equivalents at end of year	$ 146	$ 361	$ 126
Supplemental Cash Flow Information:			
Cash paid (received) during the year for:			
Interest and related charges, excluding capitalized amounts	$ 1,007	$ 926	$ 941
Income taxes	399	(8)	(32)

Noncash investing and financing activities:			
Assumption of debt related to acquisitions of nonutility generating facilities	62	213	
Proceeds held in escrow from sale of gas and oil properties		156	
Dominion Capital Inc. exchange of notes	258		
Exchange of debt securities		325	500

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

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Notes to Consolidated Financial Statements

Note 1. Nature of Operations

Dominion Resources, Inc. (Dominion) is a fully integrated gas and electric holding company headquartered in Richmond, Virginia. Our principal 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 within an area of approximately 30,000 square miles in Virginia and northeastern North Carolina. Virginia Power serves approximately 2.3 million retail customer accounts, including governmental agencies and wholesale customers such as rural electric cooperatives and municipalities. On May 1, 2005, Virginia Power became a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO). As a result, Virginia Power transferred functional control of its electric transmission facilities to PJM and integrated its control area into the PJM energy markets.

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. Its regulated gas distribution subsidiaries serve approximately 1.7 million residential, commercial and industrial gas sales and transportation customer accounts in Ohio, Pennsylvania and West Virginia and its nonregulated retail energy marketing businesses serve approximately 1.2 million residential, industrial and commercial customer accounts in the Northeast, Mid-Atlantic and Midwest. CNG also operates an interstate gas transmission pipeline and underground natural gas storage system in the Northeast, Mid-Atlantic and Midwest and a liquefied natural gas (LNG) import and storage facility in Maryland. Its producer services operations involve the aggregation of natural gas supply and related wholesale activities. CNG s exploration and production operations are located in several major gas and oil producing basins in the United States, both onshore and offshore.

DEI is involved in merchant generation, energy marketing and risk management activities and natural gas and oil exploration and production.

VPEM provides fuel and risk management services to Virginia Power and other Dominion affiliates and engages in energy trading activities. VPEM was formerly an indirect wholly-owned subsidiary of Virginia Power, however on December 31, 2005, Virginia Power transferred VPEM to Dominion through a series of dividend distributions.

We have substantially exited the core operating businesses of Dominion Capital, Inc. (DCI), whose primary business was financial services, including loan administration, commercial lending and residential mortgage lending.

We manage our daily operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion Exploration & Production (E&P). In addition, we report a Corporate segment that includes our corporate, service company and other functions (including unallocated debt), corporate-wide enterprise commodity risk management and optimization services, DCI, the net impact of our discontinued telecommunications operations that were sold in May 2004 and specific items attributable to our operating segments that are excluded from the profit measures evaluated by management in assessing segment performance or allocating resources among the segments. Our assets remain wholly owned by our legal subsidiaries.

The terms Dominion, Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Dominion Resources, Inc., one of Dominion Resources, Inc. s consolidated subsidiaries or operating segments or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries.

Note 2. Significant Accounting Policies

General

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

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

Certain amounts in the 2004 and 2003 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2005 presentation.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. Our customer accounts receivable at December 31, 2005 and 2004 included $396 million and $384 million, respectively, of accrued unbilled revenue based on estimated amounts of electric energy or natural gas delivered but not yet billed to our utility customers. We estimate unbilled utility revenue based on historical usage, applicable customer rates, weather factors and, for electric customers, total daily electric generation supplied after adjusting for estimated losses of energy during transmission.

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

- **Regulated electric sales** consist primarily of state-regulated retail electric sales, federally-regulated wholesale electric sales and electric transmission services subject to cost-of-service rate regulation;
- **Nonregulated electric sales** consist primarily of sales of electricity from merchant generation facilities at market-based rates, sales of electricity to residential and commercial customers at contracted fixed prices and market-based rates and electric trading revenue;
- **Regulated gas sales** consist primarily of state-regulated retail natural gas sales and related distribution services;
- **Nonregulated gas sales** consist primarily of sales of natural gas at market-based rates and contracted fixed prices, sales of gas purchased from third parties and gas trading and marketing revenue;

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Notes to Consolidated Financial Statements, Continued

- **Other energy-related commodity sales** consist primarily of sales of coal, emissions allowances held for resale and extracted products and sales activity related to agreements used to facilitate the marketing of oil production (buy/sell arrangements) described in Note 4;
- **Gas transportation and storage** consists primarily of regulated sales of gathering, transmission, distribution and storage services. Also included are regulated gas distribution charges to retail distribution service customers opting for alternate suppliers;
- **Gas and oil production** consists primarily of sales of natural gas, oil and condensate produced by us including the recognition of revenue previously deferred in connection with the volumetric production payment (VPP) transactions described in Note 12. Gas and oil production revenue is reported net of royalties; and
- **Other revenue** consists primarily of miscellaneous service revenue from electric and gas distribution operations; gas and oil processing and handling revenue; and business interruption insurance revenue associated with delayed gas and oil production caused by Hurricane Ivan.

See *Derivative Instruments* for a discussion of accounting changes we adopted October 1, 2003 that impacted the recognition and classification of changes in fair value, including settlements, of contracts held for energy trading and other purposes.

Electric Fuel, Purchased Energy and Purchased Gas Deferred Costs

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

As for electric fuel and purchased energy expenses, effective January 1, 2004, the fuel factor provisions for our Virginia retail customers are locked in until the earlier of July 1, 2007 or the termination of capped rates, with a one-time adjustment of the fuel factor, effective July 1, 2007 through December 31, 2010, with no deferred fuel accounting. As a result, approximately 12% of the cost of fuel used in electric generation and energy purchases used to serve utility customers is subject to deferral accounting. Prior to the amendments to the Virginia Electric Utility Restructuring Act (Virginia Restructuring Act) and the Virginia fuel factor statute in 2004, approximately 93% of the cost of fuel used in electric generation and energy purchases used to serve utility customers had been subject to deferral accounting. Deferred costs associated with the Virginia jurisdictional portion of expenditures incurred through 2003 continue to be reported as regulatory assets, and are subject to recovery through future rates.

Income Taxes

We file a consolidated federal income tax return for Dominion and its subsidiaries. Statement of Financial Accounting Standards (SFAS) No. 109, *Accounting for Income Taxes*, requires an asset and liability approach to accounting for income taxes. Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Where permitted by regulatory authorities, the treatment of temporary differences may differ from the requirements of SFAS No. 109. Accordingly, a regulatory asset is recognized if it is probable that future revenues will be provided for the payment of deferred tax liabilities. We establish a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. Deferred investment tax credits are amortized over the service lives of the properties giving rise to the credits.

Stock-based Compensation

We measure compensation expense for stock-based awards issued to our employees using the intrinsic value method prescribed by Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Under this method, compensation expense for restricted stock awards equals the fair value of our common stock on the date of grant. Stock option awards generally do not result in compensation expense since their exercise price is typically equal to the market price of our common stock on the date of grant. Compensation expense, if any, for both types of awards is recognized on a straight-line basis over the stated vesting period of the award.

The following table illustrates the pro forma effect on net income and earnings per share (EPS) if we had applied the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, to stock-based employee compensation:

Year Ended December 31, (millions, except per share amounts)	2005	2004	2003
Net income as reported	$ 1,033	$ 1,249	$ 318
Add: actual stock-based compensation expense, net of tax[1]	15	10	10
Deduct: pro forma stock-based compensation expense, net of tax	(16)	(20)	(36)
Net income pro forma	$ 1,032	$ 1,239	$ 292
Basic EPS as reported	$ 3.02	$ 3.80	$ 1.00
Basic EPS pro forma	3.02	3.77	0.92
Diluted EPS as reported	3.00	3.78	1.00
Diluted EPS pro forma	3.00	3.75	0.92

(1) Actual stock-based compensation expense primarily relates to restricted stock.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until actually presented for payment. At December 31, 2005 and 2004, accounts payable includes $150 million and $129 million, respectively, of checks outstanding but not yet presented for payment. For purposes of our Consolidated Statements of Cash Flows, we consider cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with a remaining maturity of three months or less.

Inventories

Materials and supplies and fossil fuel inventories are valued primarily using the weighted-average cost method. Stored gas inventory used in local gas distribution operations is valued using the last-in-first-out (LIFO) method. Under the LIFO method, those inventories were valued at $128 million at December 31, 2005 and $59 million at December 31, 2004. Based on the

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Notes to Consolidated Financial Statements, Continued

average price of gas purchased during 2005, the cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by approximately $392 million. Stored gas inventory held by certain nonregulated gas operations is valued using the weighted-average cost method.

Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered from or received by a pipeline system or storage facility differs from the contractual amount of natural gas delivered or received. We value these imbalances due to or from shippers and operators at an appropriate index price, subject to the terms of our tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due from others are reported in other current assets and imbalances owed to others are reported in other current liabilities on our Consolidated Balance Sheets.

Derivative Instruments

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

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

As part of our overall strategy to market energy and manage related risks, we manage a portfolio of commodity-based derivative instruments held for trading purposes. We use established policies and procedures to manage the risks associated with the price fluctuations in these energy commodities and use various derivative instruments to reduce risk by creating offsetting market positions.

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

Statement of Income Presentation:

- *Derivatives Held for Trading Purposes:* All changes in fair value, including amounts realized upon settlement, are presented in revenue on a net basis as nonregulated electric sales, nonregulated gas sales and other energy-related commodity sales.
- *Financially-Settled Derivatives Not Held for Trading Purposes and Not Designated as Hedging Instruments:* All unrealized changes in fair value and settlements are presented in other operations and maintenance expense on a net basis.
- *Physically-Settled Derivatives Not Held for Trading Purposes and Not Designated as Hedging Instruments:* Effective October 1, 2003, all unrealized changes in fair value and settlements for physical derivative sales contracts are presented in revenue, while all unrealized changes in fair value and settlements for physical derivative purchase contracts are reported in expenses. For periods prior to October 1, 2003, unrealized changes in fair value for physically settled derivative contracts are presented in other operations and maintenance expense on a net basis.

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

Derivative Instruments Designated as Hedging Instruments

We designate a substantial portion of our derivative instruments as cash flow or fair value hedges for accounting purposes. For all derivatives designated as hedges, the relationship between the hedging instrument and the hedged item is formally documented, as well as the risk management objective and strategy for using the hedging instrument. We assess whether the hedging relationship between the derivative and the

hedged item is highly effective at offsetting changes in cash flows or fair values both at the inception of the hedging relationship and on an ongoing basis. Any change in fair value of the derivative that is not effective at offsetting changes in the cash flows or fair values of the hedged item is recognized currently in earnings. Also, we may elect to exclude certain gains or losses on hedging instruments from the measurement of hedge effectiveness, such as gains or losses attributable to changes in the time value of options or changes in the difference between spot prices and forward prices, thus requiring that such changes be recorded currently in earnings. We discontinue hedge accounting prospectively for derivatives that have ceased to be highly effective hedges.

Cash Flow Hedges A significant portion of our hedge strategies represents cash flow hedges of the variable price risk associated with the purchase and sale of electricity, natural gas and oil. We also use foreign currency forward contracts to hedge the variability in foreign exchange rates and interest rate swaps to hedge our exposure to variable interest rates on long-term debt. For transactions in which we are hedging the variability of cash flows, changes in the fair value of the derivative are reported in accumulated other comprehensive income (loss) (AOCI), to the extent effective at offsetting changes in the hedged item, until earnings are affected by the hedged item. For cash flow hedge transactions, we discontinue hedge accounting if the occurrence of the forecasted transaction is determined to be no longer probable. We reclassify any derivative gains or losses reported in AOCI to earnings when the forecasted item is included in earnings, if it should occur, or earlier, if it becomes probable that the forecasted transaction will not occur.

Fair Value Hedges We also use fair value hedges to mitigate the fixed price exposure inherent in certain firm commodity commitments and natural gas inventory. In addition, we have designated interest rate swaps as fair value hedges to manage our interest rate exposure on certain fixed rate long-term debt. For fair value hedge transactions, changes in the fair value of the

Notes to Consolidated Financial Statements, Continued

derivative are generally offset currently in earnings by the recognition of changes in the hedged item s fair value.

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

Valuation Methods

Fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, we seek indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, we must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis.

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

Investment Securities

We account for and classify investments in marketable equity and debt securities in two categories. Debt and equity securities purchased and held with the intent of selling them in the near-term are classified as trading securities. Trading securities are reported at fair value with net realized and unrealized gains and losses included in earnings. All other debt and equity securities, including all investments held by our nuclear decommissioning trusts, are classified as available-for-sale securities.

Available-for-sale securities are reported at fair value with realized gains and losses and any other-than-temporary declines in fair value included in earnings and unrealized gains and losses reported as a component of AOCI, net of tax.

We analyze all securities classified as available-for-sale to determine whether a decline in fair value should be considered other-than-temporary. Retained interests from securitizations of financial assets are evaluated in accordance with Emerging Issues Task Force (EITF) Issue No. 99-20, *Recognition of Interest Income and Impairments of Purchased and Retained Beneficial Interests in Securitized Financial Assets*. For other securities, we use several criteria to evaluate other-than-temporary declines, including length of time over which the market value has been lower than its cost, the percentage of the decline as compared to its average cost and the expected fair value of the security. If the market value of the security has been less than cost for more than eight months and the decline in value is greater than 50% of its average cost, the security is written down to fair value at the end of the reporting period. If only one of the above criteria is met, a further analysis is performed to evaluate the expected recovery value based on third-party price targets. If the third-party price targets are below the security s average cost and one of the other criteria has been met, the decline is considered other-than-temporary and the security is written down to fair value at the end of the reporting period.

Property, Plant and Equipment

Property, plant and equipment, including additions and replacements, is recorded at original cost, including labor, materials, asset retirement costs and other direct and indirect costs including capitalized interest. The cost of repairs and maintenance, including minor additions and replacements,

is charged to expense as incurred. In 2005, 2004 and 2003, we capitalized interest costs of $99 million, $70 million and $96 million, respectively.

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

For generation-related and nonutility property, cost of removal not associated with AROs is charged to expense as incurred. We record gains and losses upon retirement of generation-related and nonutility property based upon the difference between proceeds received, if any, and the property s undepreciated basis at the retirement date.

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

(percent)	2005	2004	2003
Generation	2.04	1.97	1.83
Transmission	2.25	2.21	2.22
Distribution	3.19	3.19	3.18
Storage	3.15	3.04	2.81
Gas gathering and processing	2.21	2.31	2.39
General and other	5.80	6.03	5.73

Our nonutility property, plant and equipment, excluding exploration and production properties, is depreciated using the straight-line method over the following estimated useful lives:

Asset	Estimated Useful Lives
Merchant generation nuclear	29 44 years
Merchant generation other	6 65 years
General and other	3 25 years

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Notes to Consolidated Financial Statements, Continued

Nuclear fuel used in electric generation is amortized over its estimated service life on a units-of-production basis.

We follow the full cost method of accounting for gas and oil exploration and production 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. These capitalized costs are subject to a quarterly ceiling test. Under the ceiling test, amounts capitalized are limited to the present value of estimated future net revenues to be derived from the anticipated production of proved gas and oil reserves, assuming period-end pricing adjusted for cash flow hedges in place. If net capitalized costs exceed the ceiling test at the end of any quarterly period, then a permanent write-down of the assets must be recognized in that period. The ceiling test is performed separately for each cost center, with cost centers established on a country-by-country basis. Approximately 10% of our anticipated production is hedged by qualifying cash flow hedges, for which hedge-adjusted prices were used to calculate estimated future net revenue. Whether period-end market prices or hedge-adjusted prices were used for the portion of production that is hedged, there was no ceiling test impairment as of December 31, 2005. Future cash flows associated with settling AROs that have been accrued on our Consolidated Balance Sheets pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations*, are excluded from our calculations under the full cost ceiling test.

Depreciation of gas and oil producing properties is computed using the units-of-production method. Under the full cost method, the depreciable base of costs subject to amortization also 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. The costs of investments in unproved properties are initially excluded from the depreciable base. Until the properties are evaluated, a ratable portion of the capitalized costs is periodically reclassified to the depreciable base, determined on a property by property basis, over terms of underlying leases. Once a property has been evaluated, any remaining capitalized costs are then transferred to the depreciable base. 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.

Emissions Allowances

Emissions allowances are issued by the Environmental Protection Agency (EPA) and permit the holder of the allowance to emit certain gaseous by-products of fossil fuel combustion, including sulfur dioxide (SO_2) and nitrogen oxide (NO_x). Allowances may be transacted with third parties or consumed as these emissions are generated. Allowances allocated to or acquired by our generation and LNG operations are held primarily for consumption. Allowances acquired by our trading and risk management operations are held primarily for the purpose of resale to third parties.

Allowances Held for Consumption

Allowances held for consumption are classified as intangible assets which are included in other assets on our Consolidated Balance Sheets. Carrying amounts are based upon our cost to acquire the allowances, or in the case of a business combination, the fair values assigned to them in our allocation of the purchase price of the acquired business. Allowances issued directly to us by the EPA are carried at zero cost.

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

Allowances Held for Resale

Allowances held for resale are classified as materials and supplies inventory on our Consolidated Balance Sheets. Carrying amounts are based upon our cost to acquire the allowances.

These allowances are not consumed and therefore are not subject to amortization. We report purchases and sales of these allowances as operating activities on our Consolidated Statements of Cash Flows. Sales of these allowances are reported in operating revenue and purchases of allowances are reported in other energy-related commodity purchases expense on our Consolidated Statements of Income.

Goodwill and Intangible Assets

We evaluate goodwill for impairment annually, as of April 1st, and whenever an event occurs or circumstances change in the interim that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Intangible assets with finite lives are amortized over their estimated useful lives or as consumed.

Impairment of Long-Lived and Intangible Assets

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

Regulatory Assets and Liabilities

For utility operations subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, we defer these costs as regulatory assets that otherwise would be expensed by nonregulated companies. Likewise, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates and when revenue is collected from customers for expenditures that are not yet incurred. Regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the recovery period authorized by the regulator.

Asset Retirement Obligations

We recognize AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of the retirement activities to be performed. These amounts are capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, we estimate fair value using discounted cash flow analyses. We report the accretion of the AROs due to the passage of time in other operations and maintenance expense.

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Amortization of Debt Issuance Costs

We defer and amortize debt issuance costs and debt premiums or discounts over the expected lives of the respective debt issues, considering maturity dates and, if applicable, redemption rights held by others. As permitted by regulatory authorities, gains or losses resulting from the refinancing of debt allocable to utility operations subject to cost-based rate regulation have also been deferred and are amortized over the lives of the new issues.

Note 3. Newly Adopted Accounting Standards

2005

SFAS No. 153

On July 1, 2005, we adopted SFAS No. 153, *Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29*, which requires that all commercially substantive exchange transactions, for which the fair value of the assets exchanged are reliably determinable, be recorded at fair value, whether or not they are exchanges of similar productive assets. This amends the exception from fair value measurements in APB Opinion No. 29, *Accounting for Nonmonetary Transactions*, for nonmonetary exchanges of similar productive assets and replaces it with an exception for only those exchanges that do not have commercial substance. There was no impact on our results of operations or financial condition related to our adoption of SFAS No. 153 and we do not expect the ongoing application of SFAS No. 153 to have a material impact on our results of operations or financial condition.

FIN 47

We adopted Financial Accounting Standards Board (FASB) Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47) on December 31, 2005. FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when the obligation is incurred generally upon acquisition, construction, or development and/or through the normal operation of the asset, if the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Uncertainty about the timing and/or method of settlement is required to be factored into the measurement of the liability when sufficient information exists. Our adoption of FIN 47 resulted in the recognition of an after-tax charge of $6 million, representing the cumulative effect of the change in accounting principle.

Presented below are our pro forma net income and earnings per share as if we had applied the provisions of FIN 47 as of January 1, 2003.

Year Ended December 31, (millions, except per share amounts)	2005	2004	2003
Net income as reported	$ 1,033	$ 1,249	$ 318
Net income pro forma	1,038	1,248	317
Basic EPS as reported	3.02	3.80	1.00
Basic EPS pro forma	3.03	3.79	1.00
Diluted EPS as reported	3.00	3.78	1.00
Diluted EPS pro forma	3.02	3.78	1.00

If we had applied the provisions of FIN 47 as of January 1, 2003, our asset retirement obligations would have increased by $124 million, $131 million and $140 million, as of January 1, 2003, December 31, 2003 and December 31, 2004, respectively.

2004

FIN 46R

We adopted FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R), for our interests in VIEs that are not considered special purpose entities on March 31, 2004. FIN 46R addresses the identification and consolidation of VIEs, which are entities that are not controllable through voting interests or in which the VIEs equity investors do not bear the residual economic risks and rewards in proportion to voting rights. There was no impact on our results of operations or financial position related to this adoption. See Note 16.

EITF 04-8

On December 31, 2004, we adopted EITF Issue No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share*, which requires the shares issuable under contingently convertible instruments to be included in the diluted EPS calculation regardless of whether the market price trigger (or other contingent feature) has been met. Prior to adoption, we exchanged $219 million of outstanding contingent convertible senior notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. The new notes outstanding on December 31, 2004 were included in the diluted EPS calculation retroactive to the date of issuance using the method described in EITF 04-8. Under this method, the number of shares included in the denominator of the diluted EPS calculation is calculated as the net shares issuable for the reporting period based upon the average market price for the period. This did not result in an increase to the average shares outstanding used in the 2004 calculation of our diluted EPS since the conversion price included in the notes was greater than the average market price. In 2005, we exchanged an additional $1 million of outstanding contingent convertible senior notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash.

2003

SFAS No. 143

Effective January 1, 2003, we adopted SFAS No. 143, which provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. The effect of adopting SFAS No. 143 for 2003, as compared to an estimate of net income reflecting the continuation of former accounting policies, was to increase net income by $201 million. The increase is comprised of a $180 million after-tax benefit, representing the cumulative effect of a change in accounting principle and an increase in income before the cumulative effect of a change in accounting principle of $21 million.

EITF 02-3

On January 1, 2003, we adopted EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, that rescinded EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk*

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Notes to Consolidated Financial Statements, Continued

Management Activities. Adopting EITF 02-3 resulted in the discontinuance of fair value accounting for non-derivative contracts held for trading purposes. Those contracts are recognized as revenue or expense at the time of contract performance, settlement or termination. The EITF 98-10 rescission was effective for non-derivative energy trading contracts initiated after October 25, 2002. For all non-derivative energy trading contracts initiated prior to October 25, 2002, we recognized a charge of $67 million ($43 million after-tax) as the cumulative effect of this change in accounting principle on January 1, 2003.

EITF 03-11

We adopted EITF Issue No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not Held for Trading Purposes as Defined in EITF Issue No. 02-3*, on October 1, 2003. EITF 03-11 addresses classification of income statement related amounts for derivative contracts. Income statement amounts related to periods prior to October 1, 2003 are presented as originally reported. See Note 2.

Statement 133 Implementation Issue No. C20

In connection with a request to reconsider an interpretation of SFAS No. 133, the FASB issued 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*. Issue C20 establishes criteria for determining whether a contract s pricing terms that contain broad market indices (e.g., the consumer price index) could qualify as a normal purchase or sale and, therefore, not be subject to fair value accounting. We had several contracts that qualified as normal purchase and sales contracts under the Issue C20 guidance. However, the adoption of Issue C20 required those contracts to be initially recorded at fair value as of October 1, 2003, resulting in the recognition of an after-tax charge of $75 million, representing the cumulative effect of the change in accounting principle. As normal purchase and sales contracts, no further changes in fair value were recognized.

FIN 46R

On December 31, 2003, we adopted FIN 46R for our interests in special purpose entities, resulting in the consolidation of several special purpose lessor entities through which we had constructed, financed and leased several new power generation projects, as well as our corporate headquarters and aircraft. As a result, our Consolidated Balance Sheet as of December 31, 2003 reflected an additional $644 million in net property, plant and equipment and deferred charges and $688 million of related debt. This resulted in additional depreciation expense of approximately $20 million in both 2005 and 2004. The cumulative effect in 2003 of adopting FIN 46R for our interests in special purpose entities was an after-tax charge of $27 million, representing depreciation expense and amortization associated with the consolidated assets.

From 1997 through 2002, we established five capital trusts that sold trust preferred securities to third-party investors. We received the proceeds from the sale of the trust preferred securities in exchange for various junior subordinated notes issued to be held by the trusts. Upon adoption of FIN 46R, we began reporting as long-term debt our junior subordinated notes held by the trusts rather than the trust preferred securities. As a result, in 2005 and 2004, we reported interest expense on the junior subordinated notes rather than preferred distribution expense on the trust preferred securities.

Note 4. Recently Issued Accounting Standards

SFAS No. 123R

SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 123R), requires that compensation cost relating to share-based payment transactions be recognized in the financial statements based on the fair value of the equity or liability instruments issued. SFAS No. 123R covers a wide range of share-based compensation arrangements, including share options, restricted share plans, performance-based awards, share appreciation rights and employee share purchase plans. In addition, SFAS No. 123R clarifies the timing of expense recognition for share-based awards with terms that accelerate vesting upon retirement.

Our restricted stock awards contain terms that accelerate vesting upon retirement. Under current practice, compensation cost for these awards is recognized over the stated vesting term unless vesting is actually accelerated by retirement. Upon adoption of SFAS No. 123R, we will continue to recognize compensation cost over the stated vesting term for existing restricted stock awards, but will be required to recognize compensation cost over the shorter of the stated vesting term or period from the date of grant to the date of retirement eligibility for newly issued or modified restricted stock awards. At December 31, 2005, unrecognized compensation cost for restricted stock awards held by retirement eligible employees totaled $9 million.

SFAS No. 123R also requires the benefits of tax deductions in excess of recognized share-based compensation expense to be classified as a financing cash flow, rather than as an operating cash flow. This requirement will reduce net operating cash flow and increase net financing cash flow in periods after adoption.

We adopted SFAS No. 123R and related guidance on January 1, 2006, using the modified prospective transition method. Under this transition method, compensation cost will be recognized (a) based on the requirements of SFAS No. 123R for all share-based awards granted subsequent to January 1, 2006 and (b) based on the original provisions of SFAS No. 123 for all awards granted prior to January 1, 2006, but not vested as of this date. Results for prior periods will not be restated. The ongoing application of SFAS No. 123R is not expected to have a material impact on our results of operations or financial condition.

SFAS No. 154

In May 2005, the FASB issued SFAS No. 154*, Accounting Changes and Error Corrections*. SFAS No. 154 applies to all voluntary changes in accounting principle and requires retrospective application to prior periods financial statements of a voluntary change in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. We will apply the provisions of SFAS No. 154 to voluntary accounting changes on or after January 1, 2006.

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EITF 04-5

In June 2005, the FASB ratified the consensus reached by the EITF on Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*. EITF 04-5 provides guidance in assessing when a general partner should consolidate its investment in a limited partnership or similar entity. The provisions of EITF 04-5 were required to be applied beginning June 30, 2005 by general partners of all newly formed limited partnerships and for existing limited partnerships for which the partnership agreements are modified and is effective for general partners in all other limited partnerships beginning January 1, 2006. There was no impact on our results of operations or financial condition related to our adoption of EITF 04-5.

EITF 04-13

We enter into buy/sell and related agreements primarily as a means to reposition our offshore Gulf of Mexico crude oil production to more liquid marketing locations onshore. We typically enter into either a single or a series of buy/sell transactions in which we sell our crude oil production at the offshore field delivery point and buy similar quantities at Cushing, Oklahoma for sale to third parties. We are able to enhance profitability by selling to a wide array of refiners and/or trading companies at Cushing, one of the largest crude oil markets in the world, versus restricting sales to a limited number of refinery purchasers in the Gulf of Mexico.

Under the primary guidance of EITF Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent,* we present the sales and purchases related to our crude oil buy/sell arrangements on a gross basis in our Consolidated Statements of Income. These transactions require physical delivery of the crude oil and the risks and rewards of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling and counterparty nonperformance risk. Sale activity included in operating revenue was $377 million, $290 million and $181 million in 2005, 2004 and 2003, respectively. Purchase activity included in other energy-related commodity purchases expense was $362 million, $271 million and $163 million in 2005, 2004 and 2003, respectively.

In September 2005, the FASB ratified the EITF s consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, that will require buy/sell and related agreements to be presented on a net basis in the Consolidated Statements of Income if they are entered into in contemplation of one another. This new guidance is required to be applied to all new arrangements entered into, and modifications or renewals of existing arrangements, beginning April 1, 2006. We are currently assessing the impact that this new guidance may have on our income statement presentation of these transactions; however, there will be no impact on our results of operations or cash flows.

Note 5. Acquisitions

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, collectively referred to as Dominion New England, include the 1,560-megawatt Brayton Point Station in Somerset, Massachusetts; the 754-megawatt Salem Harbor Station in Salem, Massachusetts; and the 432-megawatt Manchester Street Station in Providence, Rhode Island. The operations of Dominion New England are included in the Dominion Generation operating segment.

Kewaunee Power Station

In July 2005, we completed the acquisition of the 556-megawatt Kewaunee nuclear power station (Kewaunee), located in northeastern Wisconsin, from Wisconsin Public Service Corporation, a subsidiary of WPS Resources Corporation (WPS), and Wisconsin Power and Light Company (WP&L), a subsidiary of Alliant Energy Corporation for approximately $192 million in cash. We sell 100% of the facility s output to WPS (59%) and WP&L (41%) under two power purchase agreements that will expire in 2013. The operations of Kewaunee are included in the Dominion Generation operating segment.

The purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values as of the date of the acquisition. We may make adjustments to the initial purchase price allocation to reflect the receipt of additional information.

Note 6. Operating Revenue

Our operating revenue consists of the following:

Year Ended December 31, (millions)	2005	2004	2003
Electric sales:			
Regulated	$ 5,543	$ 5,180	$ 4,876
Nonregulated	3,113	1,249	1,130
Gas sales:			
Regulated	1,763	1,422	1,258
Nonregulated	2,945	2,082	1,718
Other energy-related commodity sales	1,672	1,272	588
Gas transportation and storage	900	802	740
Gas and oil production	1,704	1,636	1,503
Other	401	348	282
Total operating revenue	$18,041	$13,991	$12,095

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Note 7. Income Taxes

Income from continuing operations before provision for income taxes (pre-tax income), classified by source of income, and the details of income tax expense for continuing operations were as follows:

Year Ended December 31, (millions)	2005	2004	2003
Income from continuing operations before income tax expense:			
U.S.	$ 1,587	$ 1,938	$ 1,506
Non-U.S.	29	26	40
Total	1,616	1,964	1,546
Income tax expense:			
Current			
Federal	410	62	121
State	104	82	22
Non-U.S.		(3)	1
Total current	514	141	144
Deferred			
Federal	88	580	433
State	(18)	(16)	32
Non-U.S.	15	12	6
Total deferred	85	576	471
Amortization of deferred investment tax credits net	(17)	(17)	(18)
Total income tax expense	$ 582	$ 700	$ 597

For continuing operations, the statutory U.S. federal income tax rate reconciles to our effective income tax rates as follows:

Year Ended December 31,	2005	2004	2003
U.S. statutory rate	35.0%	35.0%	35.0%
Increases (reductions) resulting from:			
Valuation allowance	1.2	(0.3)	4.0
State income taxes, net of federal benefit	3.4	2.2	2.2
Utility plant differences		0.1	(0.4)
Preferred dividends	0.3	0.3	0.4
Amortization of investment tax credits	(0.8)	(0.7)	(0.9)
Other benefits and taxes / foreign operations	(0.4)		(0.5)
Employee pension and other benefits	(1.2)	(0.5)	(0.7)
Employee stock ownership plan and restricted stock dividends	(0.8)	(0.5)	(0.7)
Other, net	(0.7)		0.2
Effective tax rate	36.0%	35.6%	38.6%

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Our net deferred income taxes consist of the following:

At December 31, (millions)	2005	2004
Deferred income tax assets:		
Other comprehensive income	$ 1,505	$ 594
Other	644	520

Loss and credit carryforwards	**893**	798
Valuation allowance	**(339)**	(328)
Total deferred income tax assets	**2,703**	1,584
Deferred income tax liabilities:		
Depreciation method and plant basis differences	**2,798**	2,959
Partnership basis differences	**181**	167
Pension benefits	**677**	754
Gas and oil exploration and production related differences	**1,956**	1,607
Deferred state income taxes	**465**	471
Other	**624**	456
Total deferred income tax liabilities	**6,701**	6,414
Total net deferred income tax liabilities	**$ 3,998**	$ 4,830

At December 31, 2005, we had the following loss and credit carryforwards:

- Federal loss carryforwards of $1.3 billion that expire if unutilized during the period 2007 through 2024. A valuation allowance on $783 million in carryforwards has been established due to the uncertainty of realizing these future deductions;
- State loss carryforwards of $1.9 billion that expire if unutilized during the period 2006 through 2025. A valuation allowance on $844 million has been established for these carryforwards; and
- Federal and state minimum tax credits of $316 million that do not expire and other federal and state income tax credits of $74 million that will expire if unutilized during the period 2006 through 2011.

Other

We have not provided for U.S. deferred income taxes or foreign withholding taxes on remaining undistributed earnings of $146 million from our non-U.S. subsidiaries since we do not intend to repatriate those earnings.

We are routinely audited by federal and state tax authorities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret them differently. We establish liabilities for tax-related contingencies in accordance with SFAS No. 5, *Accounting for Contingencies*, and review them in light of changing facts and circumstances. Ultimate resolution of income tax matters may result in favorable or unfavorable adjustments that could be material. Our estimated income tax payments for 2005 were reduced by deducting a calendar year 2003 net operating loss, a substantial portion of which resulted from a write-off related to our discontinued telecommunications business, Dominion Fiber Ventures, LLC (DFV). The DFV deduction reduced our 2005 income tax payments by approximately $116 million. We have not yet recognized in net income any tax benefits related to the deduction. If our tax deduction is challenged and ultimately not sustained, we will have to pay $116 million

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Notes to Consolidated Financial Statements, Continued

plus accrued interest. At December 31, 2005 and December 31, 2004, our Consolidated Balance Sheets reflect $144 million and $52 million, respectively, of income tax-related contingent liabilities.

American Jobs Creation Act of 2004 (the Jobs Act)

The Jobs Act has several provisions for energy companies, including a deduction related to taxable income derived from qualified production activities. Our electric generation and oil and gas extraction activities qualify as production activities under the Jobs Act. The Jobs Act limits the deduction to the lesser of taxable income derived from qualified production activities or our consolidated federal taxable income. Our qualified production activities deduction for 2005 is limited to a minimal amount.

Also, under the Jobs Act, United States companies could have repatriated foreign earnings at a substantially reduced tax rate until December 2005. We did not repatriate any funds under this provision.

Note 8. Hedge Accounting Activities

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

Year Ended December 31, (millions)	2005	2004	2003
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:			
Fair value hedges	$ 18	$ (2)	$ (3)
Cash flow hedges [1]	(79)	10	7
Net ineffectiveness	$ (61)	$ 8	$ 4
Portion of gains (losses) on hedging instruments excluded from measurement of effectiveness and included in net income:			
Fair value hedges [2]	$ 4	$ 3	$ 1
Cash flow hedges [3]	(2)	101	7
Total	$ 2	$ 104	$ 8

(1) Represents an increase in hedge ineffectiveness expense primarily due to an increase in the fair value differential between the delivery location and commodity specifications of derivative contracts held by our exploration and production operations and the delivery location and commodity specifications of our forecasted gas and oil sales.
(2) Amounts relate to changes in the difference between spot prices and forward prices for 2005 and 2004 and to changes in options time value for 2003.
(3) Amounts relate to changes in options time value.

The following table presents selected information related to cash flow hedges included in AOCI in the Consolidated Balance Sheet at December 31, 2005:

	AOCI After Tax	Portion Expected	Maximum Term

(millions)		to be Reclassified to Earnings during the Next 12 Months After Tax	
Commodities:			
Gas	$ (1,495)	$ (821)	60 months
Oil	(548)	(313)	36 months
Electricity	(743)	(413)	36 months
Interest rate	(15)	8	246 months
Foreign currency	24	11	23 months
Total	$ (2,777)	$(1,528)	

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

Due to interruptions in the Gulf of Mexico oil production caused by Hurricane Ivan, we discontinued hedge accounting for certain cash flow hedges in September 2004 since it became probable that the forecasted sales of oil would not occur. In connection with the discontinuance of hedge accounting for these contracts we reclassified $71 million of pre-tax losses from AOCI to earnings in September 2004.

As a result of a delay in reaching anticipated production levels in the Gulf of Mexico, we discontinued hedge accounting for certain cash flow hedges in March 2005 since it became probable that the forecasted sales of oil would not occur. In connection with the discontinuance of hedge accounting for these contracts, we reclassified $30 million ($19 million after-tax) of losses from AOCI to earnings in March 2005. Through December 31, 2005, we have recognized additional losses of $29 million ($19 million after-tax) due to subsequent changes in the fair value of these contracts.

Additionally, due to interruptions in Gulf of Mexico and southern Louisiana gas and oil production caused by Hurricanes Katrina and Rita, we discontinued hedge accounting for certain cash flow hedges in August and September 2005 since it became probable that the forecasted sales of gas and oil would not occur. In connection with the discontinuance of hedge accounting for these contracts, we reclassified $423 million ($272 million after-tax) of losses from AOCI to earnings in the third quarter of 2005. Through December 31, 2005, we have recognized additional losses of $12 million ($8 million after-tax) due to subsequent changes in the fair value of these contracts. Losses related to the discontinuance of hedge accounting are reported in other operations and maintenance expense in our Consolidated Statements of Income.

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Note 9. Discontinued Operations Telecommunications Operations

DFV was a joint venture originally formed by Dominion and a third-party investor trust (Investor Trust) to fund the development of its principal subsidiary, Dominion Telecom, Inc. (Dominion Telecom). Dominion Telecom was a facilities-based interchange and emerging local carrier, providing broadband solutions to wholesale customers throughout the eastern United States. Due to a weak pricing environment resulting from excess capacity in the telecommunications industry and the markets for these services not growing at rates originally contemplated, we approved a strategy to sell our interest in the telecommunications business and began reporting Dominion Telecom as a discontinued operation in the fourth quarter of 2003.

In connection with its formation, DFV issued $665 million of 7.05% senior secured notes due March 2005 that were secured in part by Dominion convertible preferred stock held in trust. We were the beneficial owner of the trust and thus did not present the convertible preferred stock in our Consolidated Balance Sheets. During 2004, as a result of the retirement of DFV s senior notes, the trust was dissolved and the convertible preferred stock was retired.

2005 and 2004 Sale of Dominion Telecom

In May 2004, we completed the sale of our discontinued telecommunication operations to Elantic Telecom, Inc. (ETI), realizing a loss of $11 million ($7 million after-tax, $0.02 per share) related to the sale. The results of telecommunications operations, including revenue of $8 million and a loss before income taxes of $19 million, are presented as discontinued operations, on a net basis, in our Consolidated Statement of Income for 2004. In July 2004, ETI filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code, which was subsequently approved by the U.S. Bankruptcy Court. ETI s plan of reorganization became effective in May 2005, and ETI emerged from bankruptcy. In September 2005, ETI, its parent and various Dominion entities reached a comprehensive settlement of various issues that was subsequently approved by the U.S. Bankruptcy Court. We recognized a benefit of $8 million ($5 million after-tax) in 2005, from the revaluation of an outstanding guarantee associated with the sale transaction. In addition to this $8 million outstanding guarantee, we have several potential indemnification obligations related to our discontinued telecommunications operations.

2003 Asset Impairments

The change in strategy in 2003 included a review of Dominion Telecom s network assets and related inventories for impairment. As a result, we recognized a $566 million impairment of network assets and related inventories, reflecting the excess of the assets carrying amount over their estimated fair values. This amount included the allocation of $16 million to the Investor Trust, representing the minority interest s share of these charges. We determined the estimated fair values with the assistance of an independent appraiser and subsequently updated the fair values based on preliminary bids received in connection with the sale of Dominion Telecom.

Since realization of tax benefits related to the impairment charges will be dependent upon our expected future tax profile, we established a valuation allowance that completely offsets the deferred tax benefits. In addition, we increased the valuation allowance on deferred tax assets previously recognized, resulting in a $48 million increase in deferred income tax expense.

2003 Additional Investments in DFV

The DFV senior notes contained certain stock price and credit downgrade triggers that could have resulted in the issuance of the convertible preferred stock held in trust. In the first quarter of 2003, we purchased $633 million of DFV senior notes to reduce the likelihood that the remarketing of the Dominion convertible preferred stock held in trust would ever occur and, in connection with the purchase, obtained consent to remove the triggers from the indenture. We paid a total of $664 million for the notes acquired and recognized a pre-tax charge of $57 million, reported in other expenses on our Consolidated Statement of Income. The charge consisted of the premium paid to acquire the notes, the consent fee paid to the note holders and the recognition of previously unamortized debt costs. After the transaction, we owned a total of $644 million of DFV senior notes with the remaining $21 million of outstanding notes held by third parties.

We began consolidating the results of DFV in our Consolidated Financial Statements in February 2003, as a result of acquiring substantially all of DFV s outstanding senior notes. Prior to this acquisition, we accounted for DFV as an equity-method investment, due to the Investor Trust s equity investment and veto rights.

In the fourth quarter of 2003, we purchased the Investor Trust s interest in DFV for $62 million, including $2 million for accrued dividends. This transaction was accounted for as a purchase of a minority interest and $60 million was recognized as goodwill and impaired. The purchase enabled us to proceed with our strategy to sell Dominion Telecom and, accordingly, classify the business as discontinued operations as of December 31, 2003. The results of telecommunications operations, including revenue of $18 million and a loss before income taxes of $627 million, were presented as discontinued operations, on a net basis, on the Consolidated Statement of Income for 2003.

2003 Other

Also early in 2003, we recognized a $27 million charge for the reallocation of DFV s equity losses between the Investor Trust and Dominion. Based on updated projections of DFV s expected net losses, Dominion and the Investor Trust revised the allocation of equity losses, using cash allocations and liquidation provisions of the underlying limited liability company agreement rather than voting interests.

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Note 10. Earnings Per Share

The following table presents the calculation of our basic and diluted EPS:

Year Ended December 31, (millions, except per share amounts)	2005	2004	2003
Income from continuing operations before cumulative effect of changes in accounting principles	$ 1,034	$ 1,264	$ 949
Income (loss) from discontinued operations	5	(15)	(642)
Cumulative effect of changes in accounting principles	(6)		11
Net income	$ 1,033	$ 1,249	$ 318
Basic EPS			
Average shares of common stock outstanding basic	342.3	329.1	317.5
Income from continuing operations before cumulative effect of changes in accounting principles	$ 3.02	$ 3.84	$ 2.99
Income (loss) from discontinued operations	0.02	(0.04)	(2.02)
Cumulative effect of changes in accounting principles	(0.02)		0.03
Net income	$ 3.02	$ 3.80	$ 1.00
Diluted EPS			
Average shares of common stock outstanding	342.3	329.1	317.5
Net effect of potentially dilutive securities(1)	2.1	1.4	1.3
Average shares of common stock outstanding diluted	344.4	330.5	318.8
Income from continuing operations before cumulative effect of changes in accounting principles	$ 3.00	$ 3.82	$ 2.98
Income (loss) from discontinued operations	0.02	(0.04)	(2.01)
Cumulative effect of changes in accounting principles	(0.02)		0.03
Net income	$ 3.00	$ 3.78	$ 1.00

(1) Potentially dilutive securities consist of options, restricted stock, equity-linked securities, contingently convertible senior notes and shares that were issuable under a forward equity sale agreement.

Potentially dilutive securities with the right to purchase approximately 3 million, 5 million and 10 million common shares for the years ended 2005, 2004 and 2003, respectively, were not included in the respective period s calculation of diluted EPS because the exercise or purchase prices included in those instruments were greater than the average market price of the common shares.

Note 11. Investment Securities

We hold marketable debt and equity securities in nuclear decommissioning trust funds, retained interests from prior securitizations of financial assets and subordinated notes related to certain collateralized debt obligations, all of which are classified as available-for-sale. In addition, we hold marketable debt and equity securities, which are classified as trading, in rabbi trusts associated with certain deferred compensation plans.

Available-for-sale securities as of December 31, 2005 and 2004 are summarized below:

	Fair Value	Total Unrealized Gains Included in AOCI	Total Unrealized Losses Included in AOCI

(millions)			
2005			
Equity securities	**$ 1,598**	**$296**	**$25**
Debt securities	**1,157**	**11**	**8**
Total	**$ 2,755**	**$307**	**$33**
2004			
Equity securities	$ 1,229	$240	$12
Debt securities	1,044	20	1
Total	$ 2,273	$260	$13

The following table presents the fair value and gross unrealized losses of our available-for-sale securities, aggregated by investment category and the length of time the securities have been in a continuous loss position, at December 31, 2005:

	Equity Securities		Debt Securities	
(millions)	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Less than 12 months	$ 168	$17	$ 430	$7
12 months or more	38	8	40	1
Total	$ 206	$25	$ 470	$8

Debt securities backed by mortgages and loans do not have stated contractual maturities as borrowers have the right to call or repay obligations with or without call or prepayment penalties. At December 31, 2005, these debt securities totaled $285 million. The fair value of all other debt securities at December 31, 2005 by contractual maturity are as follows:

(millions)	Amount
Due in one year or less	$ 40
Due after one year through five years	260
Due after five years through ten years	290
Due after ten years	282
Total	$872

Presented below is selected information regarding the sales of investment securities. In determining realized gains and losses, the cost of these securities was determined on a specific identification basis.

Year Ended December 31, (millions)	**2005**	2004	2003
Available-for-sale securities:			
Proceeds from sales	**$ 754**	$ 463	$ 832
Realized gains	**46**	57	62
Realized losses	**49**	90	102
Trading securities:			
Net unrealized gain	**6**	4	12

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Note 12. Property, Plant and Equipment

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

At December 31, (millions)	2005	2004
Utility		
Generation	$10,243	$10,135
Transmission	3,570	3,464
Distribution	8,408	8,024
Storage	947	1,023
Nuclear fuel	870	795
Gas gathering and processing	433	418
General and other	736	774
Plant under construction	954	674
Total utility	26,161	25,307
Nonutility		
Exploration and production properties being amortized:		
Proved	9,929	8,246
Unproved	753	653
Unproved exploration and production properties not being amortized	1,022	970
Merchant generation nuclear	1,109	997
Merchant generation other	1,612	1,268
Nuclear fuel	361	271
Other including plant under construction	1,116	951
Total nonutility	15,902	13,356
Total property, plant and equipment	$42,063	$38,663

Costs of unproved properties capitalized under the full cost method of accounting that were excluded from amortization at December 31, 2005 and the years in which such excluded costs were incurred, are as follows:

(millions)	Total	2005	2004	2003	Years Prior
Property acquisition costs	$ 637	$ 89	$ 33	$ 22	$ 493
Exploration costs	221	93	67	20	41
Capitalized interest	164	44	39	45	36
Total	$ 1,022	$ 226	$ 139	$ 87	$ 570

There were no significant properties under development, as defined by the SEC, excluded from amortization at December 31, 2005. As gas and oil reserves are proved through drilling or as properties are deemed to be impaired, excluded costs and any related reserves are transferred on an ongoing, well-by-well basis into the amortization calculation.

Amortization rates for capitalized costs under the full cost method of accounting for our United States and Canadian cost centers were as follows:

Year Ended December 31, (Per Mcf Equivalent)	2005	2004	2003
United States cost center	$ 1.41	$ 1.28	$ 1.20
Canadian cost center	1.82	1.18	1.00

Volumetric Production Payment Transactions

In 2005, we received $424 million in cash for the sale of a fixed-term overriding royalty interest in certain of our natural gas reserves for the period March 2005 through February 2009. The sale reduced our proved natural gas reserves by approximately 76 billion cubic feet (bcf). While we are obligated under the agreement to deliver to the purchaser its portion of future natural gas production from the properties, we retain control of the properties and rights to future development drilling. If production from the properties subject to the sale is inadequate to deliver the approximately 76 bcf of natural gas scheduled for delivery to the purchaser, we have no obligation to make up the shortfall. Cash proceeds received from this VPP transaction were recorded as deferred revenue. We will recognize revenue from the transaction as natural gas is produced and delivered to the purchaser. We previously entered into VPP transactions in 2004 and 2003 for approximately 83 bcf for the period May 2004 through April 2008 and 66 bcf for the period August 2003 through July 2007, respectively.

Sale of British Columbia Assets

In December 2004, we sold the majority of our natural gas and oil assets in British Columbia, Canada, for $476 million, which was credited to our Canadian full cost pool. We received cash proceeds of $320 million in December 2004 and $156 million in January 2005. The properties sold produced about 30 bcf equivalent net of natural gas annually. We recorded expenses of $10 million in other operations and maintenance expense related to the sale.

Jointly-Owned Utility Plants

Our proportionate share of jointly-owned utility plants at December 31, 2005 is as follows:

(millions, except percentages)	Bath County Pumped Storage Station	North Anna Power Station	Clover Power Station
Ownership interest	60.0%	88.4%	50.0%
Plant in service	$ 1,007	$ 2,075	$ 553
Accumulated depreciation	(395)	(930)	(122)
Nuclear fuel		393	
Accumulated amortization of nuclear fuel		(312)	
Plant under construction	34	59	1

The co-owners are obligated to pay their share of all future construction expenditures and operating costs of the jointly- owned facilities in the same proportion as their respective ownership interest. We report our share of operating costs in the appropriate operating expense (electric fuel and energy purchases, other operations and maintenance, depreciation, depletion and amortization and other taxes, etc.) in our Consolidated Statements of Income.

Note 13. Goodwill and Intangible Assets

Goodwill

There was no impairment of or material change to the carrying amount or segment allocation of goodwill in 2005 or 2004.

In 2003, we recorded goodwill impairment charges of $18 million related to our DCI reporting unit. During 2003, a DCI subsidiary received an unfavorable arbitration ruling that resulted in lower margins for services provided. Another DCI subsidiary experienced delays in expanding marketing and stabilizing production efforts. As a result of these unfavorable developments, we performed goodwill impairment tests, using

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discounted cash flow analyses, which indicated that the goodwill associated with those entities was impaired.

Also in 2003, as described in Note 9, we purchased the remaining equity interest in DFV for $62 million, including $2 million for accrued dividends. This transaction was accounted for as a purchase of a minority interest and $60 million was recognized as goodwill and immediately impaired. The purchase enabled us to proceed with our strategy to sell Dominion Telecom.

Other Intangible Assets

All of our intangible assets, other than goodwill, are subject to amortization. Amortization expense for intangible assets was $130 million, $62 million and $54 million for 2005, 2004 and 2003, respectively. The acquisition of Dominion New England included certain emissions allowances that are classified as intangible assets. Approximately $245 million of the purchase price was allocated to these allowances. There were no other material acquisitions of intangible assets in 2005. In 2005, we sold certain Dominion New England emissions allowances with a carrying amount of $92 million. The components of our intangible assets are as follows:

At December 31,	2005		2004	
(millions)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Software and software licenses	$ 613	$308	$579	$269
Emissions allowances	169	50	12	4
Other	225	30	106	26
Total	$1,007	$388	$697	$299

Annual amortization expense for intangible assets is estimated to be $104 million for 2006, $92 million for 2007, $73 million for 2008, $64 million for 2009 and $38 million for 2010.

Note 14. Regulatory Assets and Liabilities

Our regulatory assets and liabilities include the following:

At December 31, (millions)	2005	2004
Regulatory assets:		
Unrecovered gas costs	$ 179	$ 52
Regulatory assets current[1]	179	52
Income taxes recoverable through future rates[2]	260	250
Deferred cost of fuel used in electric generation[3]	171	248
Other postretirement benefit costs[4]	80	96
Customer bad debts[5]	70	73
RTO start-up costs and administration fees[6]	47	41
Termination of certain power purchase agreements[7]	24	
Other	106	80
Regulatory assets non-current	758	788
Total regulatory assets	$ 937	$ 840
Regulatory liabilities:		
Provision for future cost of removal[8]	567	595

Other[9]	48	30
Total regulatory liabilities	$ 615	$ 625

(1) Reported in other current assets.
(2) Income taxes recoverable through future rates resulting from the recognition of additional deferred income taxes, not recognized under ratemaking practices.
(3) In connection with the settlement of the 2003 Virginia fuel rate proceeding, we agreed to recover previously incurred costs through June 30, 2007 without a return on a portion of the unrecovered balance. Remaining costs to be recovered totaled $139 million at December 31, 2005.
(4) Costs recognized in excess of amounts included in regulated rates charged by our regulated gas operations before rates were updated to reflect a new method of accounting and the cost related to the accrued benefit obligation recognized as part of accounting for our acquisition of CNG.
(5) Instead of recovering bad debt costs through our base rates, the Public Utilities Commission of Ohio (Ohio Commission) allows us to recover all eligible bad debt expenses through a bad debt tracker. Annually, we assess the need to adjust the tracker based on the preceding year s unrecovered deferred bad debt expense. The Ohio Commission also has authorized the collection of previously deferred costs associated with certain uncollectible customer accounts from 2001 over five years through the tracker rider. Remaining costs to be recovered totaled $35 million at December 31, 2005.
(6) The Federal Energy Regulatory Commission (FERC) has conditionally authorized our deferral of start-up costs incurred in connection with joining an RTO and ongoing administrative fees paid to PJM. We have deferred $41 million in start-up costs and administration fees and $6 million of associated carrying costs. We expect recovery from Virginia jurisdictional retail customers to commence at the end of the Virginia retail rate cap period, subject to regulatory approval.
(7) The North Carolina Utilities Commission has authorized the deferral of previously incurred costs associated with the termination of certain long-term power purchase agreements with nonutility generators. The related costs are being amortized over the original term of each agreement.
(8) Rates charged to customers by our regulated businesses include a provision for the cost of future activities to remove assets that are expected to be incurred at the time of retirement.
(9) Includes $8 million and $15 million reported in other current liabilities in 2005 and 2004, respectively.

At December 31, 2005, approximately $471 million of our regulatory assets represented past expenditures on which we do not earn a return. These expenditures consist primarily of unrecovered gas costs, RTO start-up costs and administration fees, customer bad debts and a portion of deferred fuel costs. Unrecovered gas costs, the ongoing portion of bad debts and deferred fuel are recovered within two years. The previously deferred bad debts will be recovered over a 3-year period.

Note 15. Asset Retirement Obligations

Our AROs are primarily associated with the decommissioning of our nuclear generation facilities and dismantlement and removal of gas and oil wells and platforms. However, in 2005 we recognized additional AROs due to the adoption of FIN 47, which clarified when sufficient information is available to reasonably estimate the fair value of conditional AROs. These additional AROs totaled $161 million and relate to interim retirements of natural gas gathering, transmission, distribution and storage pipeline components; the retirement of certain nonutility off shore natural gas pipelines; and the future abatement of asbestos in our generation facilities. These obligations result from certain safety and environmental activities we are required to perform when any pipeline is abandoned or asbestos is disturbed.

We also have AROs related to the retirement of the approximately 2,300 gas storage wells in our underground natural gas storage network, certain electric transmission and distribution assets located on property that we do not own, hydroelectric generation facilities and LNG processing and storage facilities. We currently do not have sufficient information to estimate a reasonable range of expected retirement dates for any of these assets. Thus, AROs for these assets will not be reflected in our Consolidated Financial Statements until sufficient information becomes available to determine a reasonable estimate of the fair value of the activities to be performed. Generally, this will

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occur when the expected retirement or abandonment dates are determined by our operational planning. The changes to our AROs during 2005 were as follows:

(millions)	Amount
Asset retirement obligations at December 31, 2004[1]	$ 1,707
Obligations incurred during the period[2]	337
Obligations settled during the period	(15)
Accretion expense	102
Revisions in estimated cash flows	(29)
Obligations recognized upon adoption of FIN 47	161
Other	(8)
Asset retirement obligations at December 31, 2005[1]	$ 2,255

(1) Includes $2 million and $6 million reported in other current liabilities in 2004 and 2005, respectively.
(2) Approximately $309 million of the obligations incurred relate to the acquisition of Kewaunee.

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2005 and 2004 the aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $2.5 billion and $2.0 billion, respectively.

Note 16. Variable Interest Entities

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

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

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

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

We have since determined that our interest in two of the potential VIEs is not significant. In addition, in May 2005, we paid $215 million to divest our interest in a long-term power tolling contract with a 551 megawatt combined cycle facility located in Batesville, Mississippi, which was considered to be a potential VIE. We decided to divest our interest in the long-term power tolling contract in connection with our reconsideration of the scope of certain trading activities, including those conducted on behalf of our business segments, and our ongoing strategy to focus on business activities within the energy intensive Northeast, Mid-Atlantic and Midwest regions of the United States.

As of December 31, 2005, no further information has been received from the three remaining potential VIEs. We will continue our efforts to obtain information and will complete an evaluation of our relationship with each of these potential VIEs if sufficient information is ultimately obtained. We have remaining purchase commitments with these three potential VIE supplier entities of $2.0 billion at December 31, 2005. We paid $196 million, $199 million and $199 million for electric generation capacity and $243 million, $149 million and $134 million for electric energy to these entities for the years ended December 31, 2005, 2004 and 2003, respectively.

In October 2005, we reached an agreement in principle to restructure three long-term power purchase contracts with two potential variable interest entities. The restructured contracts expire between 2015 and 2017 and are expected to reduce capacity and energy payments by approximately $44 million and $6 million, respectively, over the remaining term of the contracts. The transaction became effective in February 2006 and did not result in a cash outlay or charge to earnings. Total debt held by the entities is approximately $320 million. After completing our FIN 46R analysis, we concluded that although our interest in the contracts, as a result of their pricing terms, represent variable interests in these potential variable interest entities, we are not the primary beneficiary.

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

In accordance with FIN 46R, we consolidate certain variable interest lessor entities through which we have financed and leased several power generation projects. Our Consolidated Balance Sheets as of December 31, 2005 and 2004 reflect net property, plant and equipment of $943 million and $963 million, respectively and $1.1 billion of debt related to these entities. The debt is nonrecourse to us and is secured by the entities property, plant and equipment.

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Note 17. Short-Term Debt and Credit Agreements

Joint Credit Facility

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 the credit quality of our companies and their counterparties. In May 2005, we entered into a $2.5 billion five-year revolving credit facility that replaced our $1.5 billion three-year facility dated May 2004 and our $750 million three-year facility dated May 2002. This credit facility can also be used to support up to $1.25 billion of letters of credit. In February 2006, this facility was replaced by a $3.0 billion five-year credit facility that terminates in February 2011.

At December 31, 2005, total outstanding commercial paper supported by the joint credit facility was $1.6 billion, with a weighted average interest rate of 4.47%. At December 31, 2004, total outstanding commercial paper supported by previous credit agreements was $573 million, with a weighted average interest rate of 2.39%.

At December 31, 2005 and 2004, total outstanding letters of credit supported by joint credit facilities were $892 million and $183 million, respectively.

In January 2006, Virginia Power issued $450 million of 5.4% senior notes that mature in 2016 and $550 million of 6.0% senior notes that mature in 2036. Virginia Power used the proceeds from the issuance to repay short-term debt.

CNG Credit Facilities

In August 2005, CNG entered into a $1.75 billion five-year revolving credit facility that replaced its $1.5 billion three-year facility dated August 2004. The credit facility supports CNG s issuance of commercial paper and letters of credit to provide collateral required by counterparties on derivative financial contracts used by CNG in its risk management strategies for its gas and oil production. In February 2006, the facility limit was reduced to $1.70 billion. At December 31, 2005 and 2004, outstanding letters of credit under the facilities totaled $1.2 billion and $555 million, respectively.

We have also entered into several bilateral credit facilities in addition to the facilities previously discussed in order to provide collateral required on derivative contracts used in our risk management strategies for merchant generation and gas and oil production operations, respectively. Collateral requirements have increased significantly in 2005 as a result of escalating commodity prices. At December 31, 2005, we had the following letter of credit facilities:

Company	Facility Limit	Outstanding Letters of Credit	Facility Capacity Remaining	Facility Inception Date	Facility Maturity Date
(millions)					
CNG	$ 100	$ 100	$	June 2004	June 2007
CNG	100	100		August 2004	August 2009
CNG[1]	550	550		October 2004	April 2006
CNG[2]	1,900	625	1,275	August 2005	February 2006
CNG[3]	200		200	December 2005	December 2010
Dominion Resources, Inc.	150	150		September 2005	March 2006
Dominion Resources, Inc.	200	200		August 2005	February 2006
Dominion Resources, Inc.[4]	290	290		October 2005	April 2006
	$ 3,490	$ 2,015	$ 1,475		

(1) In February 2006, the facility limit was reduced to $150 million.
(2) In February 2006, CNG replaced this facility with a $1.05 billion 364-day credit facility.

(3) This facility can also be used to support commercial paper borrowings.
(4) In February 2006, the facility limit was reduced to $215 million.

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Note 18. Long-Term Debt

At December 31, (millions, except percentages)	2005 Weighted Average Coupon[1]	2005	2004
Dominion Resources, Inc.:			
Unsecured Senior and Medium-Term Notes:			
2.25% to 8.125%, due 2005 to 2010	5.13%	$ 3,212	$ 3,002
5.0% to 7.82%, due 2012 to 2035 [2]	5.82%	3,880	2,880
Unsecured Equity-Linked Senior Notes, 5.75%, due 2008		330	330
Unsecured Convertible Senior Notes, 2.125%, due 2023[3]		220	220
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts, 7.83% to 8.4%, due 2027 to 2041	8.22%	825	825
Consolidated Natural Gas Company:			
Unsecured Debentures and Senior Notes:			
5.375% to 7.375%, due 2005 to 2010	5.96%	1,050	1,200
5.0% to 6.875%, due 2011 to 2027[2]	6.19%	2,150	2,150
Secured Bank Debt, Variable Rate, due 2006[4]	3.87%	234	234
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.8%, due 2041		206	206
Virginia Electric and Power Company:			
Secured First and Refunding Mortgage Bonds:[5]			
7.625%, due 2007		215	215
7.0% to 8.625%, due 2024 to 2025			512
Secured Bank Debt, Variable Rate, due 2007[4]	3.76%	370	370
Unsecured Senior and Medium-Term Notes:			
4.50% to 5.75%, due 2006 to 2010	5.42%	1,600	1,600
4.75% to 8.625%, due 2013 to 2032	5.51%	762	706
Unsecured Callable and Puttable Enhanced Securities[SM], 4.10%, due 2038[6]		225	225
Tax-Exempt Financings:[7]			
Variable Rate, due 2008	2.62%	60	60
Variable Rates, due 2015 to 2027	2.61%	137	137
4.95% to 9.62%, due 2005 to 2010	5.54%	237	242
2.30% to 7.55%, due 2014 to 2031	5.02%	263	263
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.375%, due 2042		412	412
Dominion Energy, Inc.:			
Unsecured Medium-Term Notes, 4.92% to 6.1%, due 2005 to 2009[8]			453
Secured Senior Note, 7.33%, due 2020		222	231
Secured Bank Debt, Variable Rates, due 2006[4]	3.87%	347	347
Dominion Capital, Inc.:			
Notes, 12.5%, due 2006 to 2008		6	6
Dominion Resources Services, Inc., Secured Bank Debt, Variable Rate, due 2006[4]	4.20%	107	107
		17,070	16,933
Fair value hedge valuation[9]		(52)	11
Amounts due within one year	4.69%	(2,330)	(1,368)
Unamortized discount and premium, net		(35)	(69)
Total long-term debt		$ 14,653	$ 15,507

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2005.

(2) At the option of holders in October 2006 and August 2015, $150 million of CNG s 6.875% senior notes due 2026 and $510 million of Dominion s 5.25% senior notes due 2033, respectively, are subject to redemption at 100% of the principal amount plus accrued interest. In the event of an early redemption, we have the intent and ability to refinance CNG s 6.875% senior notes under our long-term credit facilities. Accordingly, CNG s 6.875% senior notes remain classified as long-term debt on our Consolidated Balance Sheets.

(3) Convertible into a combination of cash and shares of our common stock at any time after March 31, 2004 when the average closing price of our common stock reaches $88.32 per share for a specified period. At the option of holders on December 15, 2006, December 15,

2008, December 15, 2013, or December 15, 2018, these securities are subject to redemption at 100% of the principal amount plus accrued interest. In the event of an early redemption, we have the intent and ability to refinance this security under our long-term credit facilities. Accordingly, this security remains classified as long-term debt on our Consolidated Balance Sheets.

(4) Represents debt associated with certain special purpose lessor entities that are consolidated in accordance with FIN 46R. The debt is nonrecourse to us and is secured by the entities property, plant and equipment, which totaled $943 million and $963 million at December 31, 2005 and 2004, respectively.

(5) Substantially all of Virginia Power s property ($12.3 billion at December 31, 2005) is subject to the lien of the mortgage, securing its mortgage bonds. Due to the early redemption of $512 million of First and Refunding Mortgage Bonds in 2005, we incurred $25 million of prepayment penalties and related charges that were recognized in interest expense on our Consolidated Statement of Income.

(6) On December 15, 2008, $225 million of the 4.10% Callable and Puttable Enhanced Securities[SM] due 2038 are subject to redemption at par plus accrued interest, unless holders of related options exercise rights to purchase and remarket the notes.

(7) Certain pollution control equipment at Virginia Power s generating facilities has been pledged to support these financings. The variable rate tax-exempt financings are supported by a stand-alone $200 million three-year credit facility that terminates in May 2006. In February 2006 this facility was replaced with a five-year credit facility that terminates in February 2011.

(8) Aggregate principal amount of CAD$545 million of securities denominated in Canadian dollars and presented in US dollars, based on exchange rates as of year-end.

(9) Represents changes in fair value of certain fixed-rate long-term debt associated with fair value hedging relationships.

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Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2005 were as follows:

(millions, except percentages)	2006	2007	2008	2009	2010	Thereafter	Total
Secured First and Refunding Mortgage Bonds		$ 215					$ 215
Secured Senior Notes	$ 9	9	$ 10	$ 11	$ 12	$ 171	222
Unsecured Callable and Puttable Enhanced Securities[SM]						225	225
Tax-Exempt Financings	5	20	157	115	5	396	698
Secured Bank Debt	688	370					1,058
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts						1,443	1,443
Unsecured Senior Notes (including Medium-Term Notes)	1,626	1,863	1,013	313	1,444	6,944	13,203
Other	2		4				6
Total	$ 2,330	$ 2,477	$ 1,184	$ 439	$ 1,461	$ 9,179	$ 17,070
Weighted average coupon	4.69%	5.05%	5.18%	5.38%	6.56%	6.02%	

Our short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2005, there were no events of default under these covenants.

Convertible Securities

As described in Note 3, we entered into an exchange transaction with respect to $219 million of our outstanding contingent convertible senior notes in contemplation of the transition method provided by EITF 04-8. We exchanged the outstanding notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. The notes are valued at a conversion rate of 13.5865 shares of common stock per $1,000 principal amount of senior notes, which represents a conversion price of $73.60. Amounts payable in excess of the principal amount will be paid in common stock. The conversion rate is subject to adjustment upon certain events such as subdivisions, splits, combinations of common stock or the issuance to all common stock holders of certain common stock rights, warrants or options and certain dividend increases.

The new notes outstanding on December 31, 2004 were included in the diluted EPS calculation retroactive to the date of their issuance using the method described in EITF 04-8. Under this method, the number of shares included in the denominator of the diluted EPS calculation is calculated as the net shares issuable for the reporting period based upon the average market price for the period. This did not result in an increase to the average shares outstanding used in the calculation of our diluted EPS since the conversion price of $73.60 included in the notes was greater than the average market price of the shares.

The senior notes are convertible by holders into a combination of cash and shares of our common stock under any of the following circumstances:

(1) the price of our common stock reaches $88.32 per share for a specified period;
(2) the senior notes are called for redemption by us on or after December 20, 2006;
(3) the occurrence of specified corporate transactions; or
(4) the credit rating assigned to the senior notes by Moody s Investors Service is below Baa3 and by Standard & Poor s Rating Group, a division of the McGraw-Hill Companies, Inc., is below BBB- or the ratings are discontinued for any reason.

Since none of the conditions have been met, the senior notes are not yet subject to conversion. In 2007, we will also begin to pay contingent interest if the average trading price as defined in the indenture equals or exceeds 120% of the principal amount of the senior notes. Holders have the right to require us to purchase our senior notes for cash at 100% of the principal amount plus accrued interest in December 2006, 2008, 2013 or 2018, or if we undergo certain fundamental changes.

Equity Linked Securities

In 2002 and 2000, we issued equity-linked debt securities, consisting of stock purchase contracts and senior notes. The stock purchase contracts obligate the holders to purchase shares of our common stock from us by a settlement date, two years prior to the senior notes maturity date. The purchase price is $50 and the number of shares to be purchased will be determined under a formula based upon the average closing price of our common stock near the settlement date. The senior notes, or treasury securities in some instances, are pledged as collateral to secure the purchase of common stock under the related stock purchase contracts. The holders may satisfy their obligations under the stock purchase contracts by allowing the senior notes to be remarketed with the proceeds being paid to us as consideration for the purchase of stock. Alternatively, holders may choose to continue holding the senior notes and use other resources as consideration for the purchase of stock under the stock purchase contracts.

We make quarterly interest payments on the senior notes and quarterly payments on the stock purchase contracts at the rates presented in the following table. We have recorded the present value of the stock purchase contract payments as a liability, offset by a charge to common stock in shareholders equity. Interest payments on the senior notes are recorded as interest expense and stock purchase contract payments are charged against the liability. Accretion of the stock purchase contract liability is recorded as interest expense. In calculating diluted EPS, we apply the treasury stock method to the equity-linked debt securities. These securities did not have a significant effect on diluted EPS for 2005, 2004 or 2003.

Under the terms of the stock purchase contracts, we issued 6.7 million shares of our common stock in November 2004 and

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Notes to Consolidated Financial Statements, Continued

will issue between 4.1 million and 5.5 million shares of our common stock in May 2006. Sufficient shares of our common stock have been reserved for issuance in connection with the May 2006 stock purchase contracts.

Selected information about our equity-linked debt securities is presented below:

Date of Issuance	Units Issued	Total Net Proceeds	Total Long-term Debt	Senior Notes Annual Interest Rate	Stock Purchase Contract Annual Rate	Total Equity Charge	Stock Purchase Settlement Date	Maturity of Senior Notes
(millions, except percentages)								
2000	8.3	$400.1	$ 412.5	3.66%(1)	%(2)	$ 20.7	11/04	11/06
2002	6.6	$320.1	$ 330.0	5.75%	3.00%	$ 36.3	5/06	5/08

(1) Prior to their remarketing in November 2004, the senior notes carried an annual interest rate of 8.05%.
(2) The stock purchase contracts carried an annual interest rate of 1.45% prior to their settlement in November 2004.

Junior Subordinated Notes Payable to Affiliated Trusts

From 1997 through 2002, we established five subsidiary capital trusts, each as a finance subsidiary of the respective parent company, which holds 100% of the voting interests. The capital trusts sold trust preferred securities representing preferred beneficial interests and 97% beneficial ownership in the assets held by the capital trusts. In exchange for the funds realized from the sale of the trust preferred securities and common securities that represent the remaining 3% beneficial ownership interest in the assets held by the capital trusts, we issued various junior subordinated notes. The junior subordinated notes constitute 100% of each capital trust s assets. Each trust must redeem its trust preferred securities when their respective junior subordinated notes are repaid at maturity or if redeemed prior to maturity.

Under previous accounting guidance, we consolidated the trusts in the preparation of our Consolidated Financial Statements. In accordance with FIN 46R, we ceased to consolidate the trusts as of December 31, 2003 and instead report as long-term debt on our Consolidated Balance Sheet the junior subordinated notes issued by us and held by the trusts.

The following table provides summary information about the trust preferred securities and junior subordinated notes outstanding as of December 31, 2005:

Date Established	Capital Trusts	Units (thousands)	Rate	Trust Preferred Securities Amount	Common Securities Amount (millions)
December 1997	Dominion Resources Capital Trust I(1)	250	7.83%	$250	$ 8
January 2001	Dominion Resources Capital Trust II(2)	12,000	8.4%	300	9
January 2001	Dominion Resources Capital Trust III(3)	250	8.4%	250	8
October 2001	Dominion CNG Capital Trust I(4)	8,000	7.8%	200	6
August 2002	Virginia Power Capital Trust II(5)	16,000	7.375%	400	12

Junior subordinated notes/debentures held as assets by each capital trust were as follows:

(1) $258 million Dominion Resources, Inc. 7.83% Debentures due 12/1/2027.
(2) $309 million Dominion Resources, Inc. 8.4% Debentures due 1/30/2041.
(3) $258 million Dominion Resources, Inc. 8.4% Debentures due 1/15/2031.
(4) $206 million CNG 7.8% Debentures due 10/31/2041.
(5) $412 million Virginia Power 7.375% Debentures due 7/30/2042.

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

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Note 19. Subsidiary Preferred Stock

Dominion is authorized to issue up to 20 million shares of preferred stock. At December 31, 2005 and 2004, none were issued and outstanding.

Virginia Power is authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference. At December 31, 2005 and 2004, Virginia Power had 2.59 million preferred shares issued and outstanding. Upon involuntary liquidation, dissolution or winding-up of Virginia Power, each share would be entitled to receive $100 plus accrued dividends. Dividends are cumulative.

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

Presented below are the series of Virginia Power preferred stock not subject to mandatory redemption that were outstanding as of December 31, 2005:

Dividend	Issued and Outstanding Shares (thousands)	Entitled Per Share Upon Liquidation
$5.00	107	$112.50
4.04	13	102.27
4.20	15	102.50
4.12	32	103.73
4.80	73	101.00
7.05	500	102.82(1)
6.98	600	102.80(2)
Flex MMP 12/02, Series A	1,250	100.00(3)
Total	2,590	

(1) Through 7/31/06; $102.47 commencing 8/1/06; amounts decline in steps thereafter to $100.00 by 8/1/13.
(2) Through 8/31/06; $102.45 commencing 9/1/06; amounts decline in steps thereafter to $100.00 by 9/1/13.
(3) Dividend rate is 5.50% through 12/20/07; after which the rate will be determined according to periodic auctions for periods established by Virginia Power at the time of the auction process. This series is not callable prior to 12/20/07.

Note 20. Shareholders Equity

Issuance of Common Stock

In 2005, we received proceeds of $345 million for 5.8 million shares issued through Dominion Direct® (a dividend reinvestment and open enrollment direct stock purchase plan), employee savings plans and the exercise of employee stock options. In February 2005, Dominion Direct® and the Dominion employee savings plans 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. As of December 31, 2005, we had repurchased approximately 3.7 million shares for approximately $276 million.

Forward Equity Transaction

In September 2004, we entered into a forward equity sale agreement (forward agreement) with Merrill Lynch International (MLI), as forward purchaser, relating to 10 million shares of our common stock. The forward agreement provided for the sale of two tranches of our common stock, each with stated maturity dates and settlement prices. In connection with the forward agreement, MLI borrowed an equal number of shares of our common stock from stock lenders and, at our request, sold the borrowed shares to J.P. Morgan Securities Inc. (JPM) under a purchase agreement among Dominion, MLI and JPM. JPM subsequently offered the borrowed shares to the public. We accounted for the forward agreement as equity at its initial fair value but did not receive any proceeds from the sale of the borrowed shares.

The use of a forward agreement allowed us to avoid equity market uncertainty by pricing a stock offering under then existing market conditions, while mitigating share dilution by postponing the issuance of stock until funds were needed. Except in specified circumstances or events that would have required physical share settlement, we were able to elect to settle the forward agreement by means of a physical share, cash or net share settlement and were also able to elect to settle the agreement in whole, or in part, earlier than the stated maturity date at fixed settlement prices. Under either a physical share or net share settlement, the maximum number of shares that were deliverable under the terms of the forward agreement was limited to the 10 million shares specified in the two tranches. Assuming gross share settlement of all shares under the forward agreement, we would have received aggregate proceeds of approximately $644 million, based on maturity forward prices of $64.62 per share for the 2 million shares included in the first tranche and $64.34 per share for the 8 million shares included in the second tranche.

We elected to cash settle the first tranche in December 2004 and paid MLI $5.8 million, representing the difference between our share price and the applicable forward sale price, multiplied by the 2 million shares. Additionally, we elected to cash settle 3 million shares of the second tranche in February 2005 and paid MLI $17.4 million. We recorded the settlement payments as a reduction to common stock in our Consolidated Balance Sheets.

In April 2005, we entered into an agreement with MLI that extended the settlement date for the remaining 5 million shares of the second tranche to August 2005. In August 2005, we delivered 5 million newly issued shares of our common stock to MLI, and received proceeds of $319.7 million as final settlement of the forward agreement.

Shares Reserved for Issuance

At December 31, 2005, we had a total of 37 million shares reserved and available for issuance for the following: Dominion Direct®, employee stock awards, employee savings plans, director stock compensation plans, and stock purchase contracts associated with equity-linked debt securities.

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Accumulated Other Comprehensive Income (Loss)

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

At December 31, (millions)	2005	2004
Net unrealized losses on derivatives hedging activities	$ (2,777)	$ (1,181)
Net unrealized gains on investment securities	165	149
Minimum pension liability adjustment	(10)	(14)
Foreign currency translation adjustments	58	50
Total accumulated other comprehensive loss	$ (2,564)	$ (996)

Stock-Based Awards

In April 2005, shareholders approved the 2005 Incentive Compensation Plan (2005 Incentive Plan) for employees and the Non-Employee Directors Compensation Plan (Non-Employee Directors Plan). Both plans permit stock-based awards that include restricted stock, goal-based stock, stock options and stock appreciation rights under the 2005 Incentive Plan and restricted stock and stock options under the Non-Employee Directors Plan. Under provisions of both plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms would be set at the discretion of either the Organization, Compensation and Nominating Committee of the Board of Directors or the Board of Directors itself, as provided under each individual plan. At December 31, 2005, approximately 15.3 million shares were available for future grants under these plans. Prior to April 2005, we had an incentive compensation plan that provided stock options and restricted stock awards to directors, executives and other key employees with vesting periods from one to five years. Stock options generally had contractual terms from six and one half to ten years.

The following table provides a summary of changes in amounts of stock options outstanding as of and for the years ended December 31, 2005, 2004 and 2003. No options were granted under any plan in 2005, 2004 or 2003.

	Stock Options (thousands)	Weighted-average Exercise Price
Outstanding at December 31, 2002	21,057	$55.49
Exercisable at December 31, 2002	8,586	$47.95
Exercised, cancelled and forfeited	(2,513)	$44.39
Outstanding at December 31, 2003	18,544	$56.97
Exercisable at December 31, 2003	11,604	$54.44
Exercised, cancelled and forfeited	(4,736)	$47.67
Outstanding at December 31, 2004	13,808	$60.17
Exercisable at December 31, 2004	10,768	$60.01
Exercised, cancelled and forfeited	(5,594)	$59.79
Outstanding at December 31, 2005	8,214	$60.43
Exercisable at December 31, 2005	8,214	$60.43

The following table provides certain information about stock options outstanding as of December 31, 2005:

	Options Outstanding			Options Exercisable	
Exercise Price	Shares Outstanding	Weighted-	Weighted-average Exercise	Shares Exercisable	Weighted-average Exercise

		average Remaining Contractual Life	Price		Price
	(thousands)	(years)		(thousands)	
$ 0-$19.99	1	3.0	$19.10	1	$19.10
$20-$30.99	17	3.1	$24.62	17	$24.62
$31-$40.99	30	4.0	$39.25	30	$39.25
$41-$50.99	770	4.9	$46.20	770	$46.20
$51-$60.99	4,483	3.4	$59.93	4,483	$59.93
$61-$69	2,913	5.3	$65.38	2,913	$65.38
Total	8,214	4.2	$60.43	8,214	$60.43

During 2005, 2004 and 2003, respectively, we granted approximately 249,000 shares, 582,000 shares, and 402,000 shares of restricted stock with weighted-average fair values of $74.51, $63.29 and $56.08.

Note 21. Dividend Restrictions

The Public Utility Holding Company Act of 1935 (1935 Act) and related regulations issued by the SEC impose restrictions on the transfer and receipt of funds by a registered holding company from its subsidiaries, including a general prohibition against loans or advances being made by the subsidiaries to benefit the registered holding company. Under the 1935 Act, registered holding companies and their subsidiaries may pay dividends only from retained earnings, unless the SEC specifically authorizes payments from other capital accounts. We received dividends from our subsidiaries of $1.2 billion, $1.2 billion and $1.1 billion in 2005, 2004 and 2003, respectively.

At December 31, 2005, our consolidated subsidiaries had approximately $10.5 billion in capital accounts other than retained earnings, representing capital stock, other paid-in capital and AOCI. Dominion Resources, Inc. had approximately $8.8 billion in capital accounts other than retained earnings at December 31, 2005. Generally, such amounts are not available for the payment of dividends by affected subsidiaries, or by Dominion itself, without specific authorization by the SEC.

In response to a Dominion request, the SEC granted relief in 2000; authorizing payment of dividends by CNG from other capital accounts to Dominion in amounts of up to $1.6 billion, representing CNG s retained earnings prior to our acquisition of CNG. The SEC granted further relief in 2004, authorizing our nonutility subsidiaries to pay dividends out of capital or unearned surplus in situations where such subsidiary has received excess cash from an asset sale, engaged in a restructuring, or is returning capital to an associate company. Our ability to pay dividends on our common stock at declared rates was not impacted by the restrictions previously discussed during 2005, 2004 and 2003. We are not bound by the foregoing restrictions on dividends imposed by the 1935 Act as of February 8, 2006, the effective date on which the 1935 Act was repealed under the Energy Policy Act of 2005.

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The Virginia State Corporation Commission (Virginia Commission) may prohibit any public service company, including Virginia Power, from declaring or paying a dividend to an affiliate, if found not to be in the public interest. At December 31, 2005, 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, 2005.

See Note 18 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.

Note 22. Employee Benefit Plans

We provide certain benefits to eligible active employees, retirees and qualifying dependents. Under the terms of our benefit plans, we reserve the right to change, modify or terminate the plans. From time to time in the past, benefits have changed, and some of these changes have reduced benefits.

We maintain qualified noncontributory defined benefit pension plans covering virtually all employees. Retirement benefits are based primarily on years of service, age and compensation. Our funding policy is to generally contribute annually an amount that is in accordance with the provisions of the Employment Retirement Income Security Act of 1974. The pension program also provides benefits to certain retired executives under company-sponsored nonqualified employee benefit plans. Certain of these nonqualified plans are funded through contributions to a grantor trust.

We provide retiree health care and life insurance benefits with annual employee premiums based on several factors such as age, retirement date and years of service. In 2004, we amended our non-union retiree health care and life insurance plans. In connection with the amendment, eligible employees under age fifty-five share more of the costs of benefits with us, and certain retiree medical benefits were enhanced. We re-measured our accumulated postretirement benefit obligation (APBO) during the third quarter of 2004 and as a result reduced the liability by $59 million. The impact of re-measurement on our 2004 postretirement net periodic benefits cost was not material. We will amortize the unrecognized actuarial gains associated with the plan amendment over the average remaining service period of plan participants in accordance with SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions*.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Medicare Act) was signed into law. The Medicare Act introduces a prescription drug benefit under Medicare (Medicare Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Based on an analysis performed by a third-party actuary, we have determined that the prescription drug benefit offered under our other postretirement benefit plans is at least actuarially equivalent to Medicare Part D and therefore we expect to receive the federal subsidy offered under the Medicare Act.

We expect to receive subsidies of approximately $4 million, $5 million, $5 million, $6 million and $7 million for the years 2006, 2007, 2008, 2009 and 2010 respectively, and expect to receive approximately $50 million during the period 2011 through 2015. We considered the passage of the Medicare Act a significant event requiring remeasurement of our APBO on December 8, 2003. We will amortize the unrecognized actuarial gains associated with the benefits of the subsidy over the average remaining service period of plan participants in accordance with SFAS No. 106.

We use December 31 as the measurement date for virtually all of our employee benefit plans. We use the market-related value of pension plan assets to determine the expected return on pension plan assets, a component of net periodic pension cost. The market-related value recognizes changes in fair value on a straight-line basis over a four-year period. Changes in fair value are measured as the difference between the expected and actual plan asset returns, including dividends, interest and realized and unrealized investment gains and losses.

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Notes to Consolidated Financial Statements, Continued

The following table summarizes the changes in our pension and other postretirement benefit plan obligations and plan assets and includes a statement of the plans funded status:

Year Ended December 31, (millions)	Pension Benefits 2005	Pension Benefits 2004	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 3,410	$ 3,110	$ 1,381	$ 1,351
Acquisitions	15		44	
Service cost	110	97	64	63
Interest cost	201	190	83	83
Benefits paid	(142)	(143)	(67)	(68)
Actuarial loss during the year	231	143	143	11
Plan amendments	9	13	(26)	(59)
Benefit obligation at end of year	3,834	3,410	1,622	1,381
Change in plan assets:				
Fair value of plan assets at beginning of year	4,049	3,734	697	587
Acquisitions	15		10	
Actual return on plan assets	433	453	51	60
Contributions	5	5	72	85
Benefits paid from plan assets	(142)	(143)	(36)	(35)
Fair value of plan assets at end of year	4,360	4,049	794	697
Funded status	526	639	(828)	(684)
Unrecognized net actuarial loss	1,288	1,225	491	366
Unrecognized prior service cost (credit)	34	28	(32)	(7)
Unrecognized net transition obligation			23	27
Prepaid (accrued) benefit cost	$ 1,848	$ 1,892	$ (346)	$ (298)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid pension cost	$ 1,915	$ 1,947		
Accrued benefit liability	(115)	(94)	$ (346)	$ (298)
Intangible asset	31	15		
Accumulated other comprehensive loss	17	24		
Net amount recognized	$ 1,848	$ 1,892	$ (346)	$ (298)

The accumulated benefit obligation for all of our defined benefit pension plans was $3.3 billion and $3.0 billion at December 31, 2005 and 2004, respectively. Under our funding policies, we evaluate plan funding requirements annually, usually in the fourth quarter after receiving updated plan information from our actuary. Based on the funded status of each plan and other factors, we determine the amount of contributions for the current year, if any, at that time.

Included above are nonqualified and supplemental pension plans that do not have plan assets as defined by generally accepted accounting principles. The total projected benefit obligation for these plans was $134 million and $112 million at December 31, 2005 and 2004, respectively. The total accumulated benefit obligation for these plans was $118 million and $97 million at December 31, 2005 and 2004, respectively. Because the accumulated benefit obligation relating to these plans is in excess of the fair value of plan assets, we recognized an additional minimum liability of $48 million and $39 million at December 31, 2005 and 2004, respectively.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Other Postretirement Benefits

(millions)		
2006	$ 188	$ 74
2007	161	80
2008	161	86
2009	167	91
2010	196	97
2011-2015	1,176	580

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Notes to Consolidated Financial Statements, Continued

Our overall objective for investing our pension and other postretirement plan assets is to achieve the best possible long-term rates of return commensurate with prudent levels of risk. To minimize risk, funds are broadly diversified among asset classes, investment strategies and investment advisors. The strategic target asset allocation for our pension fund is 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. Financial derivatives may be used to obtain or manage market exposures and to hedge assets and liabilities. The asset allocations for our pension plans and other postretirement plans follow:

	Pension Plans				Other Postretirement Plans			
Year Ended December 31,	2005		2004		2005		2004	
(millions)	Fair Value	% of Total	Fair Value	% of Total	Fair Value	% of Total	Fair Value	% of Total
Equity securities:								
U.S.	$ 1,750	40	$ 1,761	44	$330	42	$308	44
International	607	14	522	13	90	11	74	11
Debt securities	990	23	947	23	289	36	250	36
Real estate	340	8	298	7	21	3	17	2
Other	673	15	521	13	64	8	48	7
Total	$ 4,360	100	$ 4,049	100	$794	100	$697	100

The components of the provision for net periodic benefit cost were as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	2005	2004	2003	2005	2004	2003
(millions)						
Service cost	$ 110	$ 97	$ 86	$ 64	$ 63	$ 55
Interest cost	201	190	182	83	83	79
Expected return on plan assets	(341)	(336)	(332)	(51)	(44)	(33)
Amortization of prior service cost (credit)	3	2	2	(1)		
Amortization of transition obligation (asset)			(2)	3	7	9
Amortization of net loss	77	56	20	19	21	20
Net periodic benefit cost (credit)	$ 50	$ 9	$ (44)	$117	$130	$130

Significant assumptions used in determining the net periodic cost recognized in our Consolidated Statements of Income were as follows, on a weighted-average basis:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	2005	2004	2003	2005	2004	2003
Discount rate	6.00%	6.25%	6.75%	6.00%	6.25%	6.75%
Expected return on plan assets	8.75%	8.75%	8.75%	8.00%	7.79%	7.78%
Rate of increase for compensation	4.70%	4.70%	4.70%	4.70%	4.70%	4.70%
Medical cost trend rate[1]				9.00%	9.00%	9.00%

(1) Decreasing to 5.00% in 2009 and years thereafter.

Significant assumptions used in determining the projected pension benefit and postretirement benefit obligations recognized in our Consolidated Balance Sheets were as follows, on a weighted-average basis:

At December 31,	Pension Benefits 2005	Pension Benefits 2004	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004
Discount rate	**5.60%**	6.00%	**5.50%**	6.00%
Rate of increase for compensation	**4.70%**	4.70%	**4.70%**	4.70%

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
- The types of investments expected to be held by the plans.

Assisted by an independent actuary, management develops assumptions, which are then compared to the forecasts of other independent investment advisors to ensure reasonableness. An internal committee selects the final assumptions.

Discount rates are determined 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.

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Notes to Consolidated Financial Statements, Continued

Assumed health care cost trend rates have a significant effect on the amounts reported for our retiree health care plans. A one-percentage-point change in assumed health care cost trend rates would have had the following effects:

(millions)	One percentage point increase	Other Postretirement Benefits One percentage point decrease
Effect on total service and interest cost components for 2005	$ 26	$ (20)
Effect on postretirement benefit obligation at December 31, 2005	$220	$179

In addition, we sponsor defined contribution thrift-type savings plans. During 2005, 2004 and 2003, we recognized $33 million, $29 million and $27 million, respectively, as contributions to these plans.

Certain regulatory authorities have held that amounts recovered in utility customers rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, certain of our subsidiaries fund postretirement benefit costs through Voluntary Employees Beneficiary Associations. Our remaining subsidiaries do not prefund postretirement benefit costs but instead pay claims as presented.

Note 23. Commitments and Contingencies

As the result of issues generated in the ordinary course of business, we are involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies, some of which involve substantial amounts of money. We believe that the final disposition of these proceedings will not have a material effect on our financial position, liquidity or results of operations.

Long-Term Purchase Agreements

At December 31, 2005, we had the following long-term commitments that are noncancelable or are cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services:

(millions)	2006	2007	2008	2009	2010	Thereafter	Total
Purchased electric capacity[1]	$ 441	$ 418	$ 387	$ 366	$ 352	$2,536	$ 4,500
Production handling for gas and oil production operations[2]	54	51	36	22	14	13	190

(1) Commitments represent estimated amounts payable for capacity under power purchase contracts with qualifying facilities and independent power producers, the last of which ends in 2023. Capacity payments under the contracts are generally based on fixed dollar amounts per month, subject to escalation using broad-based economic indices. At December 31, 2005, the present value of our total commitment for capacity payments is $2.8 billion. Capacity payments totaled $472 million, $570 million and $611 million, and energy payments totaled $378

million, $293 million and $289 million for 2005, 2004, and 2003, respectively.
(2) Payments under this contract, which ends in 2012, totaled $52 million, $22 million and $10 million in 2005, 2004 and 2003, respectively.

In the first quarter of 2005, we paid $42 million in cash and assumed $62 million of debt in connection with the termination of a long-term power purchase agreement and the acquisition of the related generating facility used by Panda-Rosemary LP, a nonutility generator, to provide electricity to us. The purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values as of the date of acquisition. In connection with the termination of the agreement, we recorded an after-tax charge of $47 million.

In the second quarter of 2005, we paid $215 million to divest our interest in a long-term power tolling contract with a 551-megawatt combined cycle facility located in Batesville, Mississippi. We recorded after-tax charges of $8 million and $112 million in 2005 and 2004, respectively, related to the divestiture of the contract.

In October 2005, we reached an agreement in principle to restructure three long-term power purchase contracts. The restructured contracts expire between 2015 and 2017 and are expected to reduce capacity and energy payments by approximately $44 million and $6 million, respectively, over the remaining term of the contracts. The transaction became effective in February 2006 and did not result in a cash outlay or charge to earnings.

Lease Commitments

We lease various facilities, onshore and offshore drilling rigs, vehicles and equipment primarily under operating leases. Payments under certain leases are escalated based on an index such as the consumer price index. Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2005 are as follows:

2006	2007	2008	2009	2010	Thereafter	Total
(millions)						
$131	$142	$142	$132	$106	$345	$998

Rental expense totaled $160 million, $123 million and $105 million for 2005, 2004 and 2003, respectively, the majority of which is reflected in other operations and maintenance expense.

We have an agreement with a voting interest entity (lessor) to lease the Fairless Energy power station in Pennsylvania (Fairless), 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, that are reflected in the lease commitments table. 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 the 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.

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Environmental Matters

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

Historically, we recovered such costs arising from regulated electric operations through utility rates. However, to the extent environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 2010, in excess of the level currently included in Virginia jurisdictional rates, our results of operations will decrease. After that date, we may seek recovery through rates of only those environmental costs related to our transmission and distribution operations.

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

In 1987, we and a number of other entities were identified by the EPA as PRPs at two Superfund sites located in Kentucky and Pennsylvania. In 2003, the EPA issued its Certificate of Completion of remediation for the Kentucky site. Future costs for the Kentucky site will be limited to minor operations and maintenance expenditures. Remediation design is complete for the Pennsylvania site, and total remediation costs are expected to be in the range of $13 million to $25 million. Based on allocation formulas and the volume of waste shipped to the site, we have accrued a reserve of $2 million to meet our obligations at these two sites. Based on a financial assessment of the PRPs involved at these sites, we have determined that it is probable that the PRPs will fully pay their share of the costs. We generally seek to recover our costs associated with environmental remediation from third-party insurers. At December 31, 2005, any pending or possible insurance claims were not recognized as an asset or offset against obligations.

Other Before being acquired by us in 2001, Louis Dreyfus Natural Gas Corp. (Louis Dreyfus) was one of numerous defendants in a lawsuit consolidated and 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 facilities operated by other defendants caused an underground hydrocarbon plume in McAllen, Texas. The plaintiffs claim that they have suffered damages, including property damage and lost profits, as a result of the alleged plume. Although the results of litigation are inherently unpredictable, we do not expect the ultimate outcome of the case to have a material adverse impact on our results of operations, cash flows or financial position.

We have determined that we are associated with 21 former manufactured gas plant sites. Studies conducted by other utilities at their former manufactured gas plants have indicated that their sites contain coal tar and other potentially harmful materials. None of the 21 former sites with which we are associated is under investigation by any state or federal environmental agency, and no investigation or action is currently anticipated. One of the former sites is conducting a state approved post closure groundwater monitoring program and an environmental land use restriction has been recorded. Regarding the other sites, it is not known to what degree these sites may contain environmental contamination. We are not able to estimate the cost, if any, that may be required for the possible remediation of these other sites.

Nuclear Operations

Nuclear Decommissioning Minimum Financial Assurance The Nuclear Regulatory Commission (NRC) requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Our 2005 NRC minimum financial assurance amount, aggregated for our nuclear units, was $2.9 billion and has been satisfied by a combination of the funds being collected and deposited in the trusts and the real annual rate of return growth of the funds allowed by the NRC. In June 2005, we gave notice to the NRC that we were canceling our previous guarantee related to the nuclear units at Virginia Power and two nuclear units at Millstone. These guarantees were cancelled because, based on our calculations, the trusts now contain sufficient funds to meet NRC requirements without further assurances.

Nuclear Insurance The Price-Anderson Act provides the public up to $10.8 billion of protection per nuclear incident via obligations required of owners of nuclear power plants. The Price-Anderson Act Amendment of 1988 allows for an inflationary provision adjustment every five years. We have purchased $300 million of coverage from the commercial insurance pools with the remainder provided through a mandatory industry risk-sharing program. With the acquisition of Kewaunee in July 2005, we have seven licensed reactors. In the event of a nuclear incident at any licensed nuclear reactor in the United States, we could be assessed up to $100.6 million for each of our seven licensed reactors not to exceed $15

million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. The Price-Anderson Act was first enacted in 1957 and was renewed again in 2005.

Our current level of property insurance coverage ($2.55 billion for North Anna, $2.55 billion for Surry, $2.75 for Millstone, and $1.8 billion for Kewaunee) exceeds the NRC s minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site and includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first to return the reactor to and maintain it in a safe and stable condition and second to decontaminate the reactor and station site in accordance with a plan approved by the NRC. Our nuclear property insurance is provided by the Nuclear Electric Insurance Limited (NEIL), a mutual insurance company, and is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance company. The maximum assessment for the current policy period is $99

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million. Based on the severity of the incident, the board of directors of our nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. We have the financial responsibility for any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination.

We purchase insurance from NEIL to cover the cost of replacement power during the prolonged outage of a nuclear unit due to direct physical damage of the unit. Under this program, we are subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. The current policy period s maximum assessment is $35 million.

Old Dominion Electric Cooperative, a part owner of North Anna Power Station, and Massachusetts Municipal Wholesale Electric Company and Central Vermont Public Service Corporation, part owners of Millstone s Unit 3, are responsible for their share of the nuclear decommissioning obligation and insurance premiums on applicable units, including any retrospective premium assessments and any losses not covered by insurance.

Spent Nuclear Fuel Under provisions of the Nuclear Waste Policy Act of 1982, we have entered into contracts with the Department of Energy (DOE) for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by our contracts with the DOE. In January 2004, we and certain of our direct and indirect subsidiaries filed a lawsuit in the United States Court of Federal Claims against the DOE in connection with its failure to commence accepting spent nuclear fuel. We will continue to safely manage our spent fuel until it is accepted by the DOE.

Guarantees, Surety Bonds and Letters of Credit

At December 31, 2005, we had issued $37 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 exploration and production 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, which is reflected in the lease commitments table, 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, which we view as highly unlikely. We have not recognized any significant liabilities related to any of these guarantee arrangements.

We also enter into guarantee arrangements on behalf of our consolidated subsidiaries primarily to facilitate their commercial transactions with third parties. To the extent that a liability subject to a guarantee has been incurred by one of our consolidated subsidiaries, that liability is included in our Consolidated Financial Statements. We are not required to recognize liabilities for guarantees issued on behalf of our subsidiaries unless it becomes probable that we will have to perform under the guarantees. No such liabilities have been recognized as of December 31, 2005. We believe it is unlikely that we would be required to perform or otherwise incur any losses associated with guarantees of our subsidiaries obligations. At December 31, 2005, we had issued the following subsidiary guarantees:

(millions)	Stated Limit	Value (1)
Subsidiary debt(2)	$1,268	$1,268
Commodity transactions(3)	3,823	1,539
Lease obligation for power generation facility(4)	898	898
Nuclear obligations(5)	355	303
Offshore drilling commitments	300	300
Other	594	413
Total	$7,238	$4,721

(1) Represents the estimated portion of the guarantee s stated limit that is utilized as of December 31, 2005 based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by our subsidiaries, the value includes the recorded amount.

(2) Guarantees of $1.1 billion of debt reflected on our December 31, 2005 balance sheet related to variable interest lessor entities through which we have financed and leased several power generation projects. In the event of default by the subsidiaries, we would be obligated to repay such amounts.

(3) Guarantees related to energy marketing activities and other commodity commitments of certain subsidiaries, including subsidiaries of CNG and DEI. These guarantees were provided to counterparties in order to facilitate physical and financial transactions in gas, oil, electricity, pipeline capacity, transportation and related commodities and services. If any of these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, we would be obligated to satisfy such obligation. We and our subsidiaries receive similar guarantees as collateral for credit extended to others. The value provided includes certain guarantees that do not have stated limits.

(4) Guarantee of a DEI subsidiary s leasing obligation for the Fairless Energy power station.

(5) Guarantees related to Virginia Power s and certain DEI subsidiaries potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and includes guarantees for Virginia Power s commitment to buy nuclear fuel. Also, as part of satisfying certain NRC requirements concerned with ensuring adequate funding for the operations of the Millstone Power Station, we have also agreed to provide up to $150 million to a DEI subsidiary, if requested by such subsidiary, to pay Millstone s operating expenses.

Additionally, as of December 31, 2005 we had purchased $70 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $4.2 billion to facilitate commercial transactions by our subsidiaries with third parties.

Indemnifications

As part of commercial contract negotiations in the normal course of business, we may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. We are unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate us have not yet occurred or, if any such event has occurred, we have not been notified of its occurrence. However, at December 31, 2005, we believe future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

Stranded Costs

In 1999, Virginia enacted the Virginia Restructuring Act that established a detailed plan to restructure Virginia s electric utility industry. Under the Virginia Restructuring Act, the generation portion of our Virginia jurisdictional operations is no longer

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subject to cost-based regulation. The legislation s deregulation of generation was an event that required us to discontinue the application of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation,* to the Virginia jurisdictional portion of our generation operations in 1999. In 2004, amendments to the Virginia Restructuring Act and the Virginia fuel factor statute were adopted. The amendments extend capped base rates by three and one-half years, to December 31, 2010, unless modified or terminated earlier under the Virginia Restructuring Act. In addition to extending capped rates, the amendments:

- Lock in our fuel factor provisions until the earlier of July 1, 2007 or the termination of capped rates under the Virginia Restructuring Act, with no adjustment for previously incurred over-recovery or under-recovery of fuel costs, thus eliminating deferred fuel accounting for the Virginia jurisdiction;
- Provide for a one-time adjustment of our fuel factor, effective July 1, 2007 through December 31, 2010 (unless capped rates are terminated earlier under the Virginia Restructuring Act), with no adjustment for previously incurred over-recovery or under-recovery of fuel costs; and
- End wires charges on the earlier of July 1, 2007 or the termination of capped rates.

Wires charges are permitted to be collected by utilities until July 1, 2007, under the Virginia Restructuring Act. Our wires charges are set at zero in 2006 for all rate classes, and as such, Virginia customers will not pay a fee if they switch from us to a different competitive service provider.

We believe capped electric retail rates and, where applicable, wires charges provided under the Virginia Restructuring Act provide an opportunity to recover our potential stranded costs, depending on market prices of electricity and other factors. Stranded costs are those 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.

Recovery of our potential stranded costs remains subject to numerous risks even in the capped-rate environment. These include, among others, exposure to long-term power purchase commitment losses, future environmental compliance requirements, changes in certain tax laws, nuclear decommissioning costs, increased fuel costs, inflation, increased capital costs and recovery of certain other items. At December 31, 2005, our exposure to potential stranded costs included: long-term power purchase agreements that could ultimately be determined to be above market; generating plants that could possibly become uneconomic in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits not yet recognized in the financial statements.

Note 24. Fair Value of Financial Instruments

Substantially all of our financial instruments are recorded at fair value, with the exception of the instruments described below that are reported at historical cost. Fair values have been determined using available market information and valuation methodologies considered appropriate by management. The financial instruments carrying amounts and fair values are as follows:

At December 31,	2005		2004	
	Carrying Amount	Estimated Fair Value (1)	Carrying Amount	Estimated Fair Value (1)
(millions)				
Long-term debt(2)	$15,567	$15,928	$15,446	$16,499
Junior subordinated notes payable to affiliated trusts	1,416	1,537	1,429	1,595

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

Note 25. Credit Risk

Credit risk is our risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, counterparties may make available collateral, including letters of credit or cash held as margin deposits, as a result of exceeding agreed-upon credit limits, or may be required to prepay the transaction. Amounts reported as margin deposit liabilities represent funds held by us that resulted from various trading counterparties exceeding agreed-upon credit limits established by us. Amounts reported as margin deposit assets represent funds held on deposit by various trading counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. As of December 31, 2005 and 2004, we had margin deposit assets (reported in other current assets) of $160 million and $179 million, respectively, and margin deposit liabilities (reported in other current liabilities) of $133 million and $28 million, respectively.

We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our December 31, 2005 provision for credit losses, that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

As a diversified energy company, we transact with major companies in the energy industry and with commercial and residential energy consumers. Except for gas and oil exploration and production business activities, these transactions principally occur in the Northeast, Mid-Atlantic and Midwest regions of the United States. We do not believe that this geographic concentration contributes significantly to our overall exposure to credit risk. In addition, as a result of our large and diverse customer

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base, we are not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations, including transmission services and retail energy sales.

Our exposure to credit risk is concentrated primarily within our sales of gas and oil production and energy marketing and risk management activities, including our hedging activities, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and risk management activities include trading of energy-related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. At December 31, 2005, gross credit exposure related to these transactions totaled $1.34 billion, reflecting the unrealized gains for contracts carried at fair value plus any outstanding receivables (net of payables, where netting agreements exist), prior to the application of collateral. After the application of collateral, our credit exposure is reduced to $1.20 billion. Of this amount, investment grade counterparties represent 69% and no single counterparty exceeded 10%.

Note 26. Equity Method Investments and Affiliated Transactions

At December 31, 2005 and 2004, our equity method investments totaled $331 million and $387 million, respectively, and equity earnings on these investments totaled $43 million in 2005, $34 million in 2004 and $25 million in 2003. We received dividends from these investments of $28 million, $37 million and $28 million in 2005, 2004 and 2003, respectively. Our equity method investments are reported on our Consolidated Balance Sheets in other investments. Equity earnings on these investments are reported on our Consolidated Statements of Income in other income (loss).

International Investments

CNG International (CNGI) was engaged in energy-related activities outside of the United States, primarily through equity investments in Australia and Argentina. After completing the CNG acquisition, we committed to a plan to dispose of the entire CNGI operation consistent with our strategy to focus on our core businesses.

During 2003, we recognized impairment losses totaling $84 million ($69 million after-tax) related primarily to investments in a pipeline business located in Australia and a small generation facility in Kauai, Hawaii that was sold in December 2003 for cash proceeds of $42 million. In 2004, we received cash proceeds of $52 million and recognized a benefit in other income of $27 million related to the sale of a portion of the Australian pipeline business.

At December 31, 2005, our remaining CNGI investment is accounted for at its fair value of $4 million. We continue to market this investment for sale.

Note 27. Dominion Capital, Inc.

We have substantially exited the core DCI financial services, commercial lending and residential mortgage lending businesses.

Our Consolidated Balance Sheets reflect the following DCI assets:

At December 31, (millions)	2005	2004
Current assets	$ 108	$ 26
Available-for-sale securities	286	335
Other investments	89	102
Property, plant and equipment, net	10	15
Deferred charges and other assets	87	121
Total	$ 580	$ 599

Securitizations of Financial Assets

At December 31, 2005 and 2004, DCI held $286 million and $335 million, respectively, of retained interests from the securitization of financial assets, which are classified as available-for-sale securities. The retained interests resulted from prior year securitizations of commercial loans receivable in collateralized loan obligation (CLO), collateralized debt obligation (CDO) and collateralized mortgage obligation (CMO) transactions.

In connection with ongoing efforts to divest our remaining financial services investments, we executed certain agreements in the fourth quarter of 2003 that resulted in the sale of commercial finance receivables, a note receivable, an undivided interest in a lease and equity investments to a new CDO structure. In exchange for the sale of these assets with an aggregate carrying amount of $123 million, we received $113 million cash and a $7 million 3% subordinated secured note in the new CDO structure and recorded an impairment charge of $3 million. The equity interests in the new CDO structure, a voting interest entity, are held by an entity that is not affiliated with us.

Simultaneous with the above transaction, the new CDO structure acquired all of the loans held by two special purpose trusts that were established in 2001 and 2000 to facilitate DCI s securitization of certain loan receivables. DCI s original transfers of the loans to the CLO trusts qualified as sales under SFAS No. 125, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. Only after receiving consents from non-affiliated third parties, the CLO trusts governing agreements were amended to permit the sale of their financial assets into the new CDO structure in 2003. In consideration for the sale of loans to the new CDO structure, the trusts received $243 million of subordinated secured 3% notes in the new CDO structure and $119 million in cash, which was used by the CLO trusts to redeem all of their outstanding senior debt securities. As of December 31, 2003, we still held residual interests in the CLO trusts, the value of which depended solely on the subordinated 3% notes issued by the new CDO. In connection with a review of the remaining assets in the CLO trusts, DCI recorded impairments totaling $23 million in 2003. We received our distribution of the new CDO notes in the first quarter of 2004 upon liquidation of the trusts.

In February 2005 the CDO structure was recapitalized to allow for additional assets. The recapitalization allows the collateral manager a twelve month ramp-up period to invest in additional eligible securities of a higher quality than previously held by the

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CDO structure. The additional assets will improve the credit quality and diversity of the portfolio thereby reducing the overall risk of the portfolio.

At the closing date of the transaction in February 2005, DCI exchanged its original $258 million Class B Notes, 3% paid-in-kind (PIK) interest for $100 million Class B-1 Notes, 7.5% current pay interest and $158 million Class B-2 Notes, 3% PIK interest. DCI also has a commitment to fund up to $15 million of liquidity.

There were no mortgage securitizations in 2004 or 2005. Activity for the subordinated notes related to the new CDO structure, retained interests from securitizations of CMOs and the CLO and CDO retained interests is summarized as follows:

		Retained Interests
(millions)	CMO	CLO/CDO
Balance at January 1, 2004	$ 141	$ 272
Liquidation of retained interest in CLO trusts		(231)
Distributions of new CDO notes to Dominion		235
Interest income		9
Amortization	(1)	
Cash received	(27)	(4)
Fair value adjustment	(46)	(13)
Balance at December 31, 2004	$ 67	$ 268
Interest income		4
Proceeds from the sale of CDOs		(16)
Other cash received	(1)	(8)
Fair value adjustment	(28)	
Balance at December 31, 2005	$ 38	$ 248

Key Economic Assumptions and Sensitivity Analysis

Retained interests in CLOs and CDOs are subject to credit loss and interest rate risk. Retained interests in CMOs are subject to credit loss, prepayment and interest rate risk. Given the declining residual balances and the lower weighted-average lives due to the passage of time, adverse changes of up to 20% in assumed prepayment speeds, credit losses and interest rates are estimated in each case to have less than a $3 million pre-tax impact on future results of operations.

Impairment Losses

The table below presents a summary of asset impairment losses associated with DCI operations.

Year Ended December 31, (millions)	2005	2004	2003
Retained interests from CMO securitizations[1]	$ 25	$ 46	$ 36
Retained interests from CLO/CDO securitizations[1]		13	15
2003 CDO transactions			23
Venture capital and other equity investments[2]	10	26	16
Deferred tax assets[3]			26
Goodwill impairment[4]			18
Total	$ 35	$ 85	$ 134

(1)

As a result of economic conditions and historically low interest rates and the resulting impact on credit losses and prepayment speeds, we recorded impairments of our retained interests from CMO, CDO and CLO securitizations in 2005, 2004 and 2003. We updated our credit loss and prepayment assumptions to reflect our recent experience.

(2) Other impairments were recorded primarily due to asset dispositions.

(3) Represents an increase in the valuation allowance related to federal tax loss carryforwards not expected to be utilized.

(4) See Note 13 for discussion of goodwill impairments.

Note 28. Operating Segments

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 company assets. The financial impact of the Clearinghouse s optimization of company assets is now reported as part of the results of the business segments operating the related assets, in order to better reflect the performance of the underlying assets. As such, activities such as fuel management, hedging, selling the output of, contracting and optimizing the Dominion Generation assets are reported in the Dominion Generation segment. Activities related to corporate-wide enterprise commodity risk management and optimization services that are not focused on any particular business segment are reported in the Corporate segment. Aggregation of gas supply and associated gas trading and marketing activities, as well as the prior year results of certain energy trading activities exited in connection with the reorganization continue to be reported in the Dominion Energy segment.

Additionally, 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 are now held for non-trading purposes. Under our derivative income statement classification policy described in Note 2, 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 reclassification as non-trading, all unrealized changes in fair value and settlements related to those derivative contracts that are financially settled are now reported in other operations and maintenance expense. The statement of income related amounts for those reclassified derivative sales contracts that are physically settled are now presented in operating revenue, while the statement of income related amounts for physically settled purchase contracts are reported in operating expenses.

Our company is organized primarily on the basis of products and services sold in the United States. We manage our operations through the following segments:

Dominion Delivery includes our regulated electric and gas distribution and customer service business, as well as nonregulated retail energy marketing operations.

Dominion Energy includes our tariff-based electric transmission, natural gas transmission pipeline and underground natural gas storage businesses and an LNG facility. It also includes certain natural gas production and producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage and associated gas trading and the prior year s results of certain energy trading activities exited in December 2004.

Dominion Generation includes the generation operations of our electric utility and merchant fleet as well as energy marketing and risk management activities associated with the optimization of generation assets.

Dominion E&P includes our gas and oil exploration, development and production operations. 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, and Western Canada.

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Corporate includes our corporate, service company and other functions (including unallocated debt), corporate-wide enterprise commodity risk management and optimization services, the remaining assets of DCI and the net impact of our discontinued telecommunications operations that were sold in May 2004. In addition, the contribution to net income by our primary operating segments is determined based on a measure of profit that executive management believes represents the segments core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by executive management in assessing the segment s performance or allocating resources among the segments and are instead reported in the Corporate segment. In 2005, we reported net expenses of $505 million in the Corporate segment attributable to our operating segments. The net expenses in 2005 primarily related to the impact of the following:

- A $556 million loss ($357 million after-tax) related to the discontinuance of hedge accounting in August and September 2005 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 and subsequent changes in the fair value of those hedges during the third quarter, attributable to Dominion E&P;
- A $77 million charge ($47 million after-tax) resulting from the termination of a long-term power purchase agreement, attributable to Dominion Generation; and
- A $51 million charge related to credit exposure associated with the bankruptcy of Calpine Corporation, attributable to Dominion Generation. We have not recognized any deferred tax benefits related to the charge, since realization of tax benefits is not anticipated at this time based on our expected future tax profile.

In 2004, we reported net expenses of $224 million in the Corporate segment attributable to our operating segments. The net expenses in 2004 primarily related to the impact of the following:

- A $184 million charge ($112 million after-tax) related to our interest in a long-term power tolling contract that was divested in 2005, attributable to Dominion Generation;
- A $96 million loss ($61 million after-tax) related to the discontinuance of hedge accounting in September 2004 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, attributable to Dominion E&P; and
- A $71 million charge ($43 million after-tax) resulting from the termination of three long-term power purchase agreements, attributable to Dominion Generation.

In 2003, we reported net expenses of $220 million in the Corporate segment attributable to our operating segments. The net expenses in 2003 primarily related to the impact of the following:

- $21 million net after-tax benefit representing the cumulative effect of adopting new accounting principles, as described in Note 3 to our Consolidated Financial Statements, including:
  - SFAS No. 143: a $180 million after-tax benefit attributable to: Dominion Generation ($188 million after-tax benefit); Dominion E&P ($7 million after-tax charge); and Dominion Delivery ($1 million after-tax charge);
  - EITF 02-3: a $67 million after-tax charge attributable to Dominion Energy;
  - Statement 133 Implementation Issue No. C20: a $75 million after-tax charge attributable to Dominion Generation; and
  - FIN 46R: a $17 million after-tax charge attributable to Dominion Generation;
- $197 million ($122 million after-tax) of incremental restoration expenses associated with Hurricane Isabel, attributable primarily to Dominion Delivery;
- A $105 million charge ($65 million after-tax) for the termination of long-term power purchase agreements attributable to Dominion Generation;
- A $64 million charge ($39 million after-tax) for the restructuring and termination of certain electric sales agreements attributable to Dominion Generation; and
- $26 million of severance costs ($15 million after-tax) for workforce reductions during the first quarter of 2003, attributable to:
  - Dominion Generation ($8 million after-tax);
  - Dominion Energy ($2 million after-tax);
  - Dominion Delivery ($4 million after-tax); and
  - Dominion Exploration & Production ($1 million after-tax).

Intersegment sales and transfers are based on underlying contractual arrangements and agreements and may result in intersegment profit or loss.

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Notes to Consolidated Financial Statements, Continued

The following table presents segment information pertaining to our operations:

Year Ended December 31, (millions)	Dominion Delivery	Dominion Energy	Dominion Generation	Dominion E&P	Corporate	Adjustments & Eliminations	Consolidated Total
2005							
Total revenue from external customers	$4,298	$1,673	$8,068	$2,644	$ 29	$ 1,329	$18,041
Intersegment revenue	39	1,407	203	246	588	(2,483)	
Total operating revenue	4,337	3,080	8,271	2,890	617	(1,154)	18,041
Depreciation, depletion and amortization	329	121	366	563	35	(2)	1,412
Equity in earnings of equity method investees	1	13	21	3	5		43
Interest income	11	12	61	15	247	(251)	95
Interest and related charges	191	84	289	140	538	(251)	991
Income tax expense (benefit)	253	212	218	324	(425)		582
Income from discontinued operations, net of tax					5		5
Cumulative effect of change in accounting principle, net of tax					(6)		(6)
Net income (loss)	448	319	402	565	(701)		1,033
Investment in equity method investees	5	97	112	42	75		331
Capital expenditures	532	399	724	1,690	13		3,358
Total assets (billions)	10.4	6.6	17.6	15.4	16.0	(13.3)	52.7
2004							
Total revenue from external customers	$3,757	$2,047	$4,925	$2,291	$ 69	$ 902	$13,991
Intersegment revenue	77	384	793	157	509	(1,920)	
Total operating revenue	3,834	2,431	5,718	2,448	578	(1,018)	13,991
Depreciation, depletion and amortization	316	116	282	558	35	(2)	1,305
Equity in earnings of equity method investees	1	12	11	(1)	11		34
Interest income	8	14	52	2	269	(244)	101
Interest and related charges	151	62	254	94	622	(244)	939
Income tax expense (benefit)	256	119	321	314	(310)		700
Loss from discontinued operations, net of tax					(15)		(15)
Net income (loss)	466	190	525	595	(527)		1,249
Investment in equity method investees	5	94	162	40	86		387
Capital expenditures	441	354	623	1,311	21		2,750
Total assets (billions)	9.2	7.2	14.5	11.3	14.3	(11.1)	45.4
2003							
Total revenue from external customers	$3,287	$1,863	$4,482	$1,858	$ 149	$ 456	$12,095
Intersegment revenue	61	493	293	150	591	(1,588)	
Total operating revenue	3,348	2,356	4,775	2,008	740	(1,132)	12,095
Depreciation, depletion and amortization	302	104	229	532	49		1,216
Equity in earnings of equity method investees		12	13	6	(6)		25
Interest income	14	8	52	1	271	(237)	109
Interest and related charges	171	64	239	82	656	(237)	975

Income tax expense (benefit)	236	223	312	220	(394)	597
Loss from discontinued operations, net of tax					(642)	(642)
Cumulative effect of changes in accounting principles, net of tax					11	11
Net income (loss)	453	346	512	415	(1,408)	318

As of December 31, 2005 and 2004, approximately 2% of our total long-lived assets were associated with international operations. For the years ended December 31, 2005, 2004 and 2003, approximately 1%, 2% and 2%, respectively, of operating revenues were associated with international operations.

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Note 29. Gas and Oil Producing Activities (unaudited)

Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil producing activities, and related aggregate amounts of accumulated depreciation, depletion and amortization follow:

At December 31, (millions)	2005	2004
Capitalized costs:		
Proved properties	$ 9,929	$ 8,246
Unproved properties	1,775	1,623
	11,704	9,869
Accumulated depletion:		
Proved properties	2,513	1,921
Unproved properties	109	109
	2,622	2,030
Net capitalized costs	$ 9,082	$ 7,839

Total Costs Incurred

The following costs were incurred in gas and oil producing activities:

Year Ended December 31,	2005			2004			2003		
(millions)	Total	United States	Canada	Total	United States	Canada	Total	United States	Canada
Property acquisition costs:									
Proved properties	$ 118	$ 118		$ 20	$ 20		$ 181	$ 181	
Unproved properties	151	137	$14	116	102	$ 14	133	125	$ 8
	269	255	14	136	122	14	314	306	8
Exploration costs	235	230	5	213	199	14	291	266	25
Development costs[1]	1,207	1,128	79	915	841	74	667	604	63
Total	$ 1,711	$ 1,613	$98	$ 1,264	$ 1,162	$102	$ 1,272	$ 1,176	$96

(1) Development costs incurred for proved undeveloped reserves were $284 million, $172 million and $182 million for 2005, 2004 and 2003, respectively.

Results of Operations

We caution that the following standardized disclosures required by the FASB do not represent our results of operations based on our historical financial statements. In addition to requiring different determinations of revenue and costs, the disclosures exclude the impact of interest expense and corporate overhead.

Year Ended December 31, (millions)	2005 Total	2005 United States	2005 Canada	2004 Total	2004 United States	2004 Canada	2003 Total	2003 United States	2003 Canada
Revenue (net of royalties) from:									
Sales to nonaffiliated companies	$ 1,499	$ 1,369	$130	$ 1,526	$ 1,297	$229	$ 1,736	$ 1,552	$184
Transfers to other operations	268	268		195	195		185	185	
Total	1,767	1,637	130	1,721	1,492	229	1,921	1,737	184
Less:									
Production (lifting) costs	443	406	37	394	309	85	357	294	63
Depreciation, depletion and amortization	564	525	39	560	497	63	526	470	56
Income tax expense	283	264	19	295	266	29	356	350	6
Results of operations	$ 477	$ 442	$ 35	$ 472	$ 420	$ 52	$ 682	$ 623	$ 59

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Company-Owned Reserves

Estimated net quantities of proved gas and oil (including condensate) reserves in the United States and Canada at December 31, 2005, 2004 and 2003, and changes in the reserves during those years, are shown in the two schedules that follow:

	2005			2004			2003		
	Total	United States	Canada	Total	United States	Canada	Total	United States	Canada
(billion cubic feet)									
Proved developed and undeveloped reserves Gas									
At January 1	4,910	4,814	96	5,161	4,718	443	4,885	4,387	498
Changes in reserves:									
Extensions, discoveries and other additions	299	276	23	387	342	45	810	767	43
Revisions of previous estimates[1]	73	71	2	2	141	(139)	(152)	(94)	(58)
Production	(290)	(275)	(15)	(348)	(312)	(36)	(375)	(335)	(40)
Purchases of gas in place	55	55		10	10		133	133	
Sales of gas in place	(85)	(85)		(302)	(85)	(217)	(140)	(140)	
At December 31	4,962	4,856	106	4,910	4,814	96	5,161	4,718	443
Proved developed reserves Gas									
At January 1	3,685	3,591	94	3,834	3,474	360	3,865	3,479	386
At December 31	3,706	3,605	101	3,685	3,591	94	3,834	3,474	360
Proved developed and undeveloped reserves Oil									
(thousands of barrels)									
At January 1	164,062	144,007	20,055	204,509	149,707	54,802	204,650	150,577	54,073
Changes in reserves:									
Extensions, discoveries and other additions	6,681	5,399	1,282	11,615	7,699	3,916	15,114	7,887	7,227
Revisions of previous estimates[2]	63,884	65,264	(1,380)	(22,925)	(1,989)	(20,936)	1,489	5,348	(3,859)
Production	(15,575)	(14,714)	(861)	(13,783)	(11,258)	(2,525)	(12,251)	(9,612)	(2,639)
Purchases of oil in place	69	69		666	666		380	380	
Sales of oil in place	(1,423)	(1,423)		(16,020)	(818)	(15,202)	(4,873)	(4,873)	
At December 31	217,698	198,602	19,096	164,062	144,007	20,055	204,509	149,707	54,802
Proved developed reserves Oil									
At January 1	113,992	102,152	11,840	88,379	55,530	32,849	94,205	59,484	34,721
At December 31	152,889	145,735	7,154	113,992	102,152	11,840	88,379	55,530	32,849

(1) Approximately 135 bcf of the 2004 Canadian reserve revisions pertained to properties sold in 2004 and resulted from performance-based reserve reclassifications from proved undeveloped to unproved.

(2) The 2005 U.S. revision is primarily due to an increase in plant liquids that resulted from a contractual change for a portion of our gas processed by third parties. We now take title to and market the natural gas liquids extracted from this gas. Approximately 17 million barrels of the 2004 Canadian reserve revisions pertained to properties sold in 2004 and resulted from performance-based reserve re-determinations on two British Columbia enhanced oil recovery projects.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

The following tabulation has been prepared in accordance with the FASB s rules for disclosure of a standardized measure of discounted future net cash flows relating to proved gas and oil reserve quantities that we own:

(millions)	2005 Total	2005 United States	2005 Canada	2004 Total	2004 United States	2004 Canada	2003 Total	2003 United States	2003 Canada
Future cash inflows[1]	$ 63,004	$ 61,112	$1,892	$ 36,819	$ 35,735	$1,084	$ 36,486	$ 32,922	$3,564
Less:									
Future development costs[2]	1,979	1,877	102	1,527	1,488	39	1,505	1,391	114
Future production costs	8,127	7,718	409	5,609	5,302	307	5,582	4,765	817
Future income tax expense	19,019	18,527	492	10,152	9,909	243	9,457	8,715	742
Future cash flows	33,879	32,990	889	19,531	19,036	495	19,942	18,051	1,891
Less annual discount (10% a year)	18,916	18,560	356	10,505	10,275	230	10,709	9,745	964
Standardized measure of discounted future net cash flows	$ 14,963	$ 14,430	$ 533	$ 9,026	$ 8,761	$ 265	$ 9,233	$ 8,306	$ 927

(1) Amounts exclude the effect of derivative instruments designated as hedges of future sales of production at year-end.
(2) Estimated future development costs, excluding abandonment, for proved undeveloped reserves are estimated to be $594 million, $330 million and $176 million for 2006, 2007 and 2008, respectively.

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In the foregoing determination of future cash inflows, sales prices for gas and oil were based on contractual arrangements or market prices at year-end. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year end, assuming the continuation of existing economic conditions. Future income taxes were computed by applying the appropriate year-end or future statutory tax rate to future pretax net cash flows, less the tax basis of the properties involved, and giving effect to tax deductions, permanent differences and tax credits.

It is not intended that the FASB s standardized measure of discounted future net cash flows represent the fair market value of our proved reserves. We caution that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

The following tabulation is a summary of changes between the total standardized measure of discounted future net cash flows at the beginning and end of each year:

(millions)	2005	2004	2003
Standardized measure of discounted future net cash flows at January 1	$ 9,026	$ 9,233	$ 7,805
Changes in the year resulting from:			
Sales and transfers of gas and oil produced during the year, less production costs	(2,502)	(2,004)	(1,997)
Prices and production and development costs related to future production	8,929	1,656	480
Extensions, discoveries and other additions, less production and development costs	1,396	1,118	1,920
Previously estimated development costs incurred during the year	284	172	182
Revisions of previous quantity estimates	27	(734)	(918)
Accretion of discount	1,367	1,359	1,149
Income taxes	(3,659)	(291)	(679)
Other purchases and sales of proved reserves in place	140	(878)	84
Other (principally timing of production)	(45)	(605)	1,207
Standardized measure of discounted future net cash flows at December 31	$ 14,963	$ 9,026	$ 9,233

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Note 30. Quarterly Financial and Common Stock Data (unaudited)

A summary of our quarterly results of operations for the years ended December 31, 2005 and 2004 follows. Amounts reflect all adjustments, consisting of only normal recurring accruals, necessary in the opinion of management for a fair statement of the results for the interim periods. Results for interim periods may fluctuate as a result of weather conditions, changes in rates and other factors.

(millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
2005					
Operating revenue	$ 4,736	$ 3,646	$ 4,564	$ 5,095	$ 18,041
Income from operations	873	705	185	676	2,439
Income from continuing operations before cumulative effect of change in accounting principle	429	332	10	263	1,034
Net income	429	332	15	257	1,033
Basic EPS:					
Income from continuing operations before cumulative effect of change in accounting principle	1.26	0.98	0.03	0.76	3.02
Net income	1.26	0.98	0.04	0.74	3.02
Diluted EPS:					
Income from continuing operations before cumulative effect of change in accounting principle	1.25	0.97	0.03	0.76	3.00
Net income	1.25	0.97	0.04	0.74	3.00
Dividends paid per share	0.67	0.67	0.67	0.67	2.68
Common stock prices (high-low)	$ 76.01-66.51	$ 76.87-67.75	$ 86.87-72.15	$ 86.97-73.50	$ 86.97-66.51
2004					
Operating revenue	$ 3,884	$ 3,045	$ 3,296	$ 3,766	$ 13,991
Income from operations	893	586	755	502	2,736
Income from continuing operations	445	258	337	224	1,264
Net income	437	251	337	224	1,249
Basic EPS:					
Income from continuing operations	1.37	0.79	1.02	0.67	3.84
Net income	1.35	0.76	1.02	0.67	3.80
Diluted EPS:					
Income from continuing operations	1.36	0.79	1.02	0.67	3.82
Net income	1.34	0.76	1.02	0.67	3.78
Dividends paid per share	0.645	0.645	0.645	0.665	2.60
Common stock prices (high-low)	$ 65.85-61.20	$ 64.75-60.78	$ 65.87-62.07	$ 68.85-62.97	$ 68.85-60.78

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

- First quarter results include a $47 million after-tax charge resulting from the termination of a long-term power purchase agreement, $31 million of after-tax losses related to the discontinuance of hedge accounting for certain oil hedges, resulting from a delay in reaching anticipated production levels in the Gulf of Mexico, and subsequent changes in the fair value of those hedges and a $28 million after-tax benefit due to the recognition of business interruption insurance revenue associated with the recovery of delayed gas and oil production due to Hurricane Ivan.
- Second quarter results include an $86 million after-tax benefit due to the final settlement of business interruption insurance claims associated with Hurricane Ivan.
- Third quarter results include a $357 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, and subsequent changes in the fair value of those hedges.
- Fourth quarter results include a $51 million after-tax charge to establish an allowance related to credit exposure associated with the bankruptcy of Calpine Corporation and a $77 million after-tax benefit reflecting the impact of a decrease in gas and oil prices on hedges that were

de-designated following Hurricanes Katrina and Rita.

Our 2004 results include the impact of the following significant items:

- Third quarter results include 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.
- Fourth quarter results include a $112 million after-tax charge related to the sale of our interest in a long-term power tolling contract that was divested in 2005, a $64 million after-tax charge resulting from the termination of two long-term power purchase agreements, and a $61 million after-tax benefit due to the recognition of business interruption insurance revenue associated with delayed gas and oil production due to Hurricane Ivan.

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Notes to Consolidated Financial Statements, Continued

Note 31. Subsequent Event

On March 1, 2006, we entered into an agreement with Equitable Resources, Inc. to sell two of our wholly-owned regulated gas distribution subsidiaries, The Peoples Natural Gas Company and Hope Gas, Inc, for $969.6 million plus adjustments to reflect capital expenditures and changes in working capital. The transaction is expected to close by the first quarter of 2007, subject to state regulatory approvals in Pennsylvania and West Virginia as well as approval under the federal Hart-Scott-Rodino Act. The carrying amounts of the major classes of assets and liabilities to be disposed of are as follows:

At December 31,	2005	2004
(millions)		
Assets		
Current assets	$ 438	$ 291
Property, plant and equipment, net	694	662
Deferred charges and other assets	107	89
Total assets	$ 1,239	$ 1,042
Liabilities		
Current liabilities	$ 323	$ 200
Deferred credits and other liabilities	209	194
Total liabilities	$ 532	$ 394

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

None.

Item 9A. Controls and Procedures

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

Management s Annual Report on Internal Control over Financial Reporting

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

We maintain a system of internal control designed to provide reasonable assurance, at a reasonable cost, that our assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Audit Committee of the Board of Directors of Dominion, composed entirely of independent directors, meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss auditing, internal control, and financial reporting matters of Dominion and to ensure that each is properly discharging its responsibilities. Both the independent registered public accounting firm and the internal auditors periodically meet alone with the Audit Committee and have free access to the Committee at any time.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act of 2002 require our 2005 Annual Report to contain a management s report and a report of the independent registered public accounting firm regarding the effectiveness of internal control. As a basis for our report, we tested and evaluated the design and operating effectiveness of internal controls. Based on our assessment as of December 31, 2005, we make the following assertion:

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

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

On December 31, 2003, we adopted Financial Accounting Standards Board Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, for our interests in special purpose entities, referred to as SPEs. As a result, we have included in our consolidated financial statements certain SPEs. Our Consolidated Balance Sheet, as of December 31, 2005, reflects $598 million of net property, plant and equipment and deferred charges and $688 million of related debt attributable to these SPEs. As these SPEs are owned by unrelated parties, we do not have the authority to dictate or modify, and therefore could not assess the internal controls in place at these entities. Our conclusion regarding the effectiveness of Dominion s internal control does not extend to the internal controls of these SPEs.

We evaluated Dominion s internal control over financial reporting as of December 31, 2005. This assessment was based on criteria for effective internal control over financial reporting described in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, we believe that Dominion maintained effective internal control over financial reporting as of December 31, 2005.

The independent registered public accounting firm that audited the financial statements has issued an attestation report on our assessment of the internal control over financial reporting.

March 2, 2006

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Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of

Dominion Resources, Inc.

We have audited management s assessment, included in paragraphs 5-8 of the accompanying Management s Annual Report on Internal Control over Financial Reporting, that Dominion Resources, Inc. maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management s Annual Report on Internal Control over Financial Reporting, management excluded from their assessment the internal control over financial reporting at certain special purpose entities consolidated under Financial Accounting Standards Board Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*. The Company s Consolidated Balance Sheet, as of December 31, 2005, reflects $598 million of net property, plant and equipment and deferred charges and $688 million of related debt attributable to these special purpose entities. Accordingly, our audit did not include the internal control over financial reporting at those special purpose entities. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2005 of the Company and our report dated March 2, 2006, expressed an unqualified opinion on those financial statements and included an explanatory paragraph referring to a change in accounting principle.

/s/ Deloitte & Touche LLP

Richmond, Virginia

March 2, 2006

Item 9B. Other Information

None.

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Part III

Item 10. Directors and Executive Officers of the Registrant

The following information is incorporated by reference from the 2006 Proxy Statement, File No. 001-08489, which will be filed on or around March 14, 2006 (the 2006 Proxy Statement):

- Information regarding the directors required by this item is found under the heading *Election of Directors*.
- Information regarding Dominion s Audit Committee required by this item is found under the heading *Governance and The Board*.
- Information regarding Dominion s Code of Ethics required by this item is found under the heading *Governance and The Board*.

The information concerning the executive officers of Dominion required by this item is included in Part I of this Form 10-K under the caption *Executive Officers of the Registrant.*

Item 11. Executive Compensation

The information regarding executive compensation contained under the headings *Committee Report on Executive Compensation* and *Executive Compensation* and the information regarding director compensation contained under the heading *Governance and The Board* in the 2006 Proxy Statement is incorporated by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information concerning stock ownership by directors, executive officers and five percent beneficial owners contained under the heading *Share Ownership* in the 2006 Proxy Statement is incorporated by reference.

The information regarding equity securities of Dominion that are authorized for issuance under its equity compensation plans contained under the heading *Executive Compensation Equity Compensation* Plans in the 2006 Proxy Statement is incorporated by reference.

Item 13. Certain Relationships and Related Transactions

The information concerning certain transactions with executive officers under the heading *Executive Compensation Executive Stock Purchase Programs* and other transactions contained under the heading *Governance and The Board Certain Relationships* in the 2006 Proxy Statement is incorporated by reference.

Item 14. Principal Accountant Fees and Services

The information concerning principal accounting fees and services contained under the heading *Auditors* in the 2006 Proxy Statement is incorporated by reference.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Certain documents are filed as part of this Form 10-K and are incorporated by reference and found on the pages noted.

1. Financial Statements

See Index on page 43.

2. Financial Statement Schedules

	Page
Report of Independent Registered Public Accounting Firm	94
Schedule I Condensed Financial Information of Registrant	95

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

3. Exhibits

3.1	Articles of Incorporation as in effect August 9, 1999, as amended effective March 12, 2001 (Exhibit 3.1, Form 10-K for the year ended December 31, 2002, File No. 1-8489, incorporated by reference).
3.2	Bylaws as in effect on October 20, 2000 (Exhibit 3, Form 10-Q for the quarter ended September 30, 2000, File No. 1-8489, incorporated by reference).
4	Dominion Resources, Inc. agrees to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of its total consolidated assets.
4.1	See Exhibit 3.1 above.
4.2	Indenture of Mortgage of Virginia Electric and Power Company, dated November 1, 1935, as supplemented and modified by fifty-eight Supplemental Indentures (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255, incorporated by reference); Sixty-Seventh Supplemental Indenture (Exhibit 4(i), Form 8-K, dated April 2, 1991, File No. 1-2255, incorporated by reference); Seventieth Supplemental Indenture, (Exhibit 4(iii), Form 8-K, dated February 25, 1992, File No. 1-2255, incorporated by reference); Seventy-First Supplemental Indenture (Exhibit 4(i)) and Seventy-Second Supplemental Indenture, (Exhibit 4(ii), Form 8-K, dated July 7, 1992, File No. 1-2255, incorporated by reference); Seventy-Third Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated August 6, 1992, File No. 1-2255, incorporated by reference); Seventy-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 10, 1993, File No. 1-2255, incorporated by reference); Seventy-Fifth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated April 6, 1993, File No. 1-2255, incorporated by reference); Seventy-Sixth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated April 21, 1993, File No. 1-2255, incorporated by reference); Seventy-Seventh Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated June 8, 1993, File No. 1-2255, incorporated by reference); Seventy-Eighth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated August 10, 1993, File No. 1-2255, incorporated by reference); Seventy-Ninth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated August 10, 1993, File No. 1-2255, incorporated by reference); Eightieth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated October 12, 1993, File No. 1-2255, incorporated by reference); Eighty-First Supplemental Indenture, (Exhibit 4(iii), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference); Eighty-Second Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated January 18, 1994, File No. 1-2255, incorporated by reference); Eighty-Third Supplemental Indenture (Exhibit 4(i), Form 8-K, dated October 19, 1994, File No. 1-2255, incorporated by reference); Eighty-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated March 23, 1995, File No. 1-2255, incorporated by reference); and Eighty-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated

February 20, 1997, File No. 1-2255, incorporated by reference).

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

4.4 Form of Senior Indenture, dated as of June 1, 1998, between Virginia Electric and Power Company and JP Morgan Chase Bank (formerly The Chase Manhattan Bank) as supplemented by the First Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 3, 1999, File No. 1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K, dated October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); and Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated January 24, 2002, incorporated by reference); Seventh Supplemental Indenture dated September 1, 2002 (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eighth Supplemental Indenture (Exhibit 4.2, Form 8-K filed February 27, 2003, File No. 1-2255, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 11, 2003, File No. 1-2255, incorporated by reference). Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Thirteenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference).

4.5 Indenture, Junior Subordinated Debentures, dated December 1, 1997, between Dominion Resources, Inc. and JP Morgan Chase Bank (formerly The Chase Manhattan Bank) as supplemented by a First Supplemental Indenture, dated December 1, 1997 (Exhibit 4.1 and Exhibit 4.2 to Form S-4 Registration Statement, File No. 333-50653, as filed on April 21, 1998, incorporated by reference); Second and Third Supplemental Indentures, dated January 1, 2001 (Exhibits 4.6 and 4.13, Form 8-K, dated January 9, 2001, incorporated by reference).

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4.6	Indenture, dated as of May 1, 1971, between Consolidated Natural Gas Company and JP Morgan Chase Bank (formerly The Chase Manhattan Bank and Manufacturers Hanover Trust Company) (Exhibit (5) to Certificate of Notification at Commission File No. 70-5012, incorporated by reference); Fifteenth Supplemental Indenture dated as of October 1, 1989 (Exhibit (5) to Certificate of Notification at Commission File No. 70-7651, incorporated by reference); Seventeenth Supplemental Indenture dated as of August 1, 1993 (Exhibit (4) to Certificate of Notification at Commission File No. 70-8167, incorporated by reference); Eighteenth Supplemental Indenture dated as of December 1, 1993 (Exhibit (4) to Certificate of Notification at Commission File No. 70-8167, incorporated by reference); Nineteenth Supplemental Indenture dated as of January 28, 2000 (Exhibit (4A)(iii), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, incorporated by reference); Twentieth Supplemental Indenture dated as of March 19, 2001 (Exhibit 4.1, Form 10-Q for the quarter ended September 30, 2003, File No. 1-3196, incorporated by reference).
4.7	Indenture, dated as of April 1, 1995, between Consolidated Natural Gas Company and The Bank of New York (as successor trustee to United States Trust Company of New York) (Exhibit (4) to Certificate of Notification at Commission File No. 70-8107); First Supplemental Indenture dated January 28, 2000 (Exhibit (4 A)(ii), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, incorporated by reference); Securities Resolution No. 1 effective as of April 12, 1995 (Exhibit 2 to Form 8-A filed April 21, 1995 under File No. 1-3196 and relating to the 7 3/8% Debentures Due April 1, 2005); Securities Resolution No. 2 effective as of October 16, 1996 (Exhibit 2 to Form 8-A filed October 18, 1996 under file No. 1-3196 and relating to the 6 7/8% Debentures Due October 15, 2006); Securities Resolution No. 3 effective as of December 10, 1996 (Exhibit 2 to Form 8-A filed December 12, 1996 under file No. 1-3196 and relating to the 6 5/8% Debentures Due December 1, 2008); Securities Resolution No. 4 effective as of December 9, 1997 (Exhibit 2 to Form 8-A filed December 12, 1997 under file No. 1-3196 and relating to the 6.80% Debentures Due December 15, 2027); Securities Resolution No. 5 effective as of October 20, 1998 (Exhibit 2 to Form 8-A filed October 22, 1998 under file No. 1-3196 and relating to the 6% Debentures Due October 15, 2010); Securities Resolution No. 6 effective as of September 21, 1999 (Exhibit 4A(iv), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-3196, and relating to the 7 1/4% Notes Due October 1, 2004, incorporated by reference).
4.8	Form of Senior Indenture, dated June 1, 2000, between Dominion Resources, Inc. and JP Morgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee (Exhibit 4 (iii), Form S-3, Registration Statement, File No. 333-93187, incorporated by reference); First Supplemental Indenture, dated June 1, 2000 (Exhibit 4.2, Form 8-K, dated June 21, 2000, File No. 1-8489, incorporated by reference); Second Supplemental Indenture, dated July 1, 2000 (Exhibit 4.2, Form 8-K, dated July 11, 2000, File No. 1-8489, incorporated by reference); Third Supplemental Indenture, dated July 1, 2000 (Exhibit 4.3, Form 8-K dated July 11, 2000, incorporated by reference); Fourth Supplemental Indenture and Fifth Supplemental Indenture dated September 1, 2000 (Exhibit 4.2, Form 8-K, dated September 8, 2000, incorporated by reference); Sixth Supplemental Indenture, dated September 1, 2000 (Exhibit 4.3, Form 8-K, dated September 8, 2000, incorporated by reference); Seventh Supplemental Indenture, dated October 1, 2000 (Exhibit 4.2, Form 8-K, dated October 11, 2000, incorporated by reference); Eighth Supplemental Indenture, dated January 1, 2001 (Exhibit 4.2, Form 8-K, dated January 23, 2001, incorporated by reference); Ninth Supplemental Indenture, dated May 1, 2001 (Exhibit 4.4, Form 8-K, dated May 25, 2001, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed March 18, 2002, File No. 1-8489, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 25, 2002, File No. 1-8489, incorporated by reference.); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed September 11, 2002, File No. 1-8489, incorporated by reference); Thirteenth Supplemental Indenture dated September 16, 2002 (Exhibit 4.1, Form 8-K filed September 17, 2002, File No. 1-8489, incorporated by reference); Fourteenth Supplemental Indenture, dated August 20, 2003 (Exhibit 4.4, Form 8-K filed August 20, 2003, File No. 1-8489, incorporated by reference); Forms of Fifteenth and Sixteenth Supplemental Indentures (Exhibits 4.2 and 4.3 to Form 8-K filed December 12, 2002, File No. 1-8489, incorporated by reference); Forms of Seventeenth and Eighteenth Supplemental Indentures (Exhibits 4.2. and 4.3 to Form 8-K filed February 11, 2003, File No. 1-8489, incorporated by reference); Forms of Twentieth and Twenty-first Supplemental Indentures (Exhibits 4.2 and 4.3 to Form 8-K filed March 4, 2003, File No. 1-8489, incorporated by reference); Form of Twenty-second Supplemental Indenture (Exhibit 4.2 to Form 8-K filed July 22, 2003, File No. 1-8489 incorporated by reference); Form of Twenty-Third Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 9, 2003, File No. 1-8489, incorporated by reference); Form of Twenty-Fifth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 14, 2004, File No. 1-8489, incorporated by reference); Form of Twenty-Sixth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 14, 2004, File No. 1-8489, incorporated by reference); Form of Twenty-Seventh Supplemental Indenture (Exhibit 4.2, Form S-4 Registration Statement, File No. 333-120339, incorporated by reference); Form of Twenty-Eighth and Twenty-Ninth Supplemental Indenture (Exhibits 4.2 and 4.3, Form 8-K filed June 17, 2005, File No. 1-8489, incorporated by reference); Form of Thirtieth Supplemental Indenture (Exhibit 4.2, Form 8-K, filed July 12, 2005, File No. 1-8489, incorporated by reference); Form of Thirty-First Supplemental Indenture (Exhibit 4.2, Form 8-K, filed September 26, 2005, File No. 1-8489, incorporated by reference).
4.9	Indenture, dated April 1, 2001, between Consolidated Natural Gas Company and Bank One Trust Company, National Association (Exhibit 4.1, Form S-3 File No. 333-52602, as filed on December 22, 2000, incorporated by reference); as supplemented by the Form of First Supplemental Indenture, dated April 1, 2001 (Exhibit 4.2, Form 8-K, File dated April 12, 2001, File No. 1-3196 incorporated by reference); Second Supplemental Indenture, dated October 25, 2001 (Exhibit 4.1, Form 8-K, dated October 23, 2001, File No. 1-3196, incorporated by reference); Third Supplemental Indenture, dated October 25, 2001 (Exhibit 4.3, Form 8-K, dated October 23, 2001, File No. 1-3196, incorporated by reference); Fourth Supplemental Indenture, dated May 1, 2002 (Exhibit 4.4, Form 8-K, dated May 22, 2002, Form 1-3196, incorporated by reference); Form of Fifth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 25, 2003, File No. 1-3196, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 16, 2004, File No. 1-3196, incorporated by reference).
4.10	Form of Indenture for Junior Subordinated Debentures, dated October 1, 2001, between Consolidated Natural Gas Company and Bank One Trust Company, National Association (Exhibit 4.2, Form S-3 Registration No. 333-52602, as filed on December 22, 2000,

incorporated by reference); as supplemented by the First Supplemental Indenture, dated October 23, 2001 (Exhibit 4.7, Form 8-K, dated October 16, 2001, File No. 1-3196, incorporated by reference).

4.11 Indenture, dated as of December 11, 1997, between Louis Dreyfus Natural Gas Corp., Dominion Oklahoma Texas Exploration & Production, Inc., and La Salle Bank National Association (formerly LaSalle National Bank) (Exhibit 4.14, Form 10-K for the fiscal year ended December 31, 2001, File No. 1-8489, incorporated by reference); as supplemented by the First Supplemental Indenture, dated as of November 1, 2001 (Exhibit 4.9, Form 10-Q for the quarter ended September 30, 2001, incorporated by reference).

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

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10.1	Amended and Restated Interconnection and Operating Agreement, dated as of July 29, 1997 between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(v), Form 10-K for the fiscal year ended December 31, 1997, File No. 1-8489, incorporated by reference).
10.2	DRI Services Agreement, dated January 28, 2000, by and between Dominion Resources, Inc., Dominion Resources Services, Inc. and Consolidated Natural Gas Service Company, Inc. (Exhibit 10(viii), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-8489, incorporated by reference).
10.3	Services Agreement between Dominion Resources Services, Inc. and Virginia Electric and Power Company dated January 1, 2000 (Exhibit 10.19, Form 10-K for the fiscal year ended December 31, 1999, File No. 1-2255, incorporated by reference).
10.4	Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-8489, incorporated by reference).
10.5	$2.5 billion Five-Year Revolving Credit Agreement, dated as of May 12, 2005, among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company and JPMorgan Chase Bank, N.A., as Administrative Agent, Citibank, N.A., as Syndication Agent, Barclays Bank PLC, The Bank of Nova Scotia and Wachovia Bank, National Association, as Co-Documentation Agents, and other lenders as named herein (Exhibit 10.1, Form 8-K filed May 18, 2005, File No. 1-8489, incorporated by reference).
10.6	$1.75 billion Five-Year Credit Agreement, dated as of August 17, 2005, among Consolidated Natural Gas Company and Barclays Bank PLC as Administrative Agent and Syndication Agent, KeyBank National Association as Syndication Agent, SunTrust Bank, The Bank of Nova Scotia and ABN Amro Bank NV as Co-Documentation Agents, and other lenders as named (Exhibit 10.1, Form 8-K filed August 18, 2005, File No. 1-8489, incorporated by reference).
10.7	$1.9 billion Credit Agreement, dated as of January 11, 2006 among Dominion Resources, Inc., Consolidated Natural Gas Company, Wachovia Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Barclays Bank PLC, as Documentation Agent, and other lenders as named therein (Exhibit 10.1, Form 8-K, filed January 13, 2006, File No. 1-8489, incorporated by reference).
10.8	Form of Settlement Agreement in the form of a proposed Consent Decree among the United States of America, on behalf of the United States Environmental Protection Agency, the State of New York, the State of New Jersey, the State of Connecticut, the Commonwealth of Virginia and the State of West Virginia and Dominion (Exhibit 10, Form 10-Q for the quarter ended March 31, 2003, File No. 1-8489, incorporated by reference).
10.9*	Dominion Resources, Inc. Executive Supplemental Retirement Plan, as amended and restated effective December 17, 2004 (Exhibit 10.5, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.10*	Dominion Resources, Inc. Incentive Compensation Plan, effective April 22, 1997, as amended and restated effective July 20, 2001 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2001, File No. 1-8489, incorporated by reference).
10.11*	Dominion Resources, Inc. 2005 Incentive Compensation Plan (Exhibit 10, Form 8-K filed March 3, 2005, File No. 1-8489, incorporated by reference).
10.12*	Dominion Resources, Inc. Executive Stock Purchase and Loan Plan II, dated February 15, 2000 (Exhibit 10.10, Form 10-K for the fiscal year ended December 31, 2002, File No. 1-8489, incorporated by reference).
10.13*	Form of Employment Continuity Agreement for certain officers of Dominion, amended and restated July 15, 2003 2001 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003, File No. 1-8489, incorporated by reference).
10.14*	Dominion Resources, Inc. Retirement Benefit Funding Plan, effective June 29, 1990 as amended and restated September 1, 1996 (Exhibit 10(iii), Form 10-Q for the quarter ended June 30, 1997, File No. 1-8489, incorporated by reference).
10.15*	Dominion Resources, Inc. Retirement Benefit Restoration Plan, as amended and restated effective December 17, 2004 (Exhibit 10.6, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.16*	Dominion Resources, Inc. Executives Deferred Compensation Plan, amended and restated effective December 17, 2004 (Exhibit 10.7, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.17*	Dominion Resources, Inc. New Executive Supplemental Retirement Plan, effective January 1, 2005 (Exhibit 10.8, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference), amended January 19, 2006 (filed herewith).
10.18*	Dominion Resources, Inc. New Retirement Benefit Restoration Plan, effective January 1, 2005 (Exhibit 10.9, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.19*	Dominion Resources, Inc. Stock Accumulation Plan for Outside Directors, amended as of February 27, 2004 (Exhibit 10.15, Form 10-K for the fiscal year ended December 31, 2003, incorporated by reference); amended effective December 31, 2004 (Exhibit 10.1, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.20*	Dominion Resources, Inc. Directors Stock Compensation Plan, as amended February 27, 2004 (Exhibit 10.16, Form 10-K for the fiscal year ended December 31, 2003, incorporated by reference); amended effective December 31, 2004 (Exhibit 10.2, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.21*	Dominion Resources, Inc. Directors Deferred Cash Compensation Plan, as amended and in effect September 20, 2002 (Exhibit 10.4, Form 10-Q for the quarter ended September 30, 2002, incorporated by reference); amended effective December 31, 2004 (Exhibit 10.3, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).

10.22* Dominion Resources, Inc. Non-Employee Directors Compensation Plan, effective January 1, 2005 (Exhibit 10.4, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).

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10.23*	Dominion Resources, Inc. Leadership Stock Option Plan, effective July 1, 2000, as amended and restated effective July 20, 2001 (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2001, File No. 1-8489, incorporated by reference).
10.24*	Dominion Resources, Inc. Executive Stock Purchase Tool Kit, effective September 1, 2001, amended and restated December 16, 2005 (Exhibit 10.2, Form 8-K filed December 12, 2005, File No. 1-8489, incorporated by reference).
10.25*	Dominion Resources, Inc. Stock Purchase Tool Kit Restricted Stock Exchange Form of Restricted Stock Award Agreement (Exhibit 10.12, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.26*	Dominion Resources, Inc. Security Option Plan, effective January 1, 2003, amended December 31, 2004 and restated effective January 1, 2005 (Exhibit 10.13, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.27*	Arrangement with Thos. E. Capps regarding additional credited years of service for retirement and retirement life insurance purposes (Exhibit 10.21, Form 10-K for the fiscal year ended December 31, 2002, File No. 1-8489, incorporated by reference).
10.28*	Employment agreement dated September 30, 2002 between Dominion and Thos. E. Capps (Exhibit 10.1, Form 10-Q for the quarter ended September 30, 2002, File No. 1-8489, incorporated by reference) including supplemental letter, dated February 27, 2003 (Exhibit 10.22, Form 10-K for the fiscal year ended December 31, 2002, File No. 1-8489, incorporated by reference); Amendment to Employment Agreement dated May 26, 2005 between Dominion Resources, Inc. and Thos. E. Capps (Exhibit 10.1, Form 8-K, filed May 31, 2005, File No. 1-8489, incorporated by reference).
10.29*	Restricted stock award agreement dated May 26, 2005 between Dominion Resources, Inc. and Thos. E. Capps (Exhibit 10.2, Form 8-K filed May 31, 2005, File No. 1-8489, incorporated by reference).
10.30*	Form of reimbursement agreement between certain executive officers and Dominion (Exhibit 10(xxvii), Form 10-K for the fiscal year ended December 31, 1999, File No. 1-2255, incorporated by reference).
10.31*	Letter agreement between Dominion and Thomas F. Farrell, II, dated February 27, 2003 (Exhibit 10.24, Form 10-K for the fiscal year ended December 31, 2002, File No. 1-8489, incorporated by reference), as amended December 16, 2005 (Exhibit 10.1, Form 8-K filed December 16, 2005, File No. 1-8489, incorporated by reference).
10.32*	Letter agreement between Dominion and Thomas N. Chewning, dated February 28, 2003 (Exhibit 10.25, Form 10-K for the fiscal year ended December 31, 2002, File No. 1-8489, incorporated by reference).
10.33*	Offer of employment dated March 16, 2001 between Dominion and Duane C. Radtke (Exhibit 10.26, Form 10-K for the fiscal year ended December 31, 2002, File No. 1-8489, incorporated by reference).
10.34*	Supplemental retirement agreement, dated October 15, 2004 between Dominion and Duane C. Radtke (Exhibit 10, Form 8-K filed October 19, 2004, File No. 1-8489, incorporated by reference).
10.35*	Employment agreement dated August 1, 1999 between Virginia Electric and Power Company and Mark F. McGettrick (Exhibit 10.20, Form 10-K for the fiscal year ended December 31, 2000, File No. 1-2255, incorporated by reference).
10.36*	Supplemental retirement agreement dated April 22, 2005 between Dominion and Mark F. McGettrick (filed herewith).
10.37*	Base salaries for named executive officers (filed herewith).
10.38*	Non-employee directors annual compensation (filed herewith).
12	Ratio of earnings to fixed charges (filed herewith).
21	Subsidiaries of the Registrant (filed herewith).
23.1	Consent of Deloitte & Touche LLP (filed herewith).
23.2	Consent of Ryder Scott Company, L.P. (filed herewith).
31.1	Certification by Registrant s Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification by Registrant s Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32	Certification to the Securities and Exchange Commission by Registrant s Chief Executive Officer and Chief Financial Officer, as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).

* Indicates management contract or compensatory plan or arrangement.

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Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of

Dominion Resources, Inc.

We have audited the consolidated financial statements of Dominion Resources, Inc. and subsidiaries (the Company) as of December 31, 2005 and 2004, and for each of the three years in the period ended December 31, 2005, management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, and the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, and have issued our reports thereon dated March 2, 2006 (which reports expressed an unqualified opinion and included an explanatory paragraph as to changes in accounting principles for: conditional asset retirement obligations in 2005 and asset retirement obligations, contracts involved in energy trading, derivative contracts not held for trading purposes, derivative contracts with a price adjustment feature, and the consolidation of variable interest entities in 2003); such reports are included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company listed in Item 15. This financial statement schedule is the responsibility of the Company s management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Richmond, Virginia

March 2, 2006

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Dominion Resources, Inc. (Parent Company)

Schedule I Condensed Financial Information of Registrant

Condensed Statements of Income

Year Ended December 31, (millions)	2005	2004	2003
Operating Expenses			
Affiliated	$ 11	$ 10	$ 22
Other	1	(5)	10
Total operating expense	12	5	32
Loss from operations	(12)	(5)	(32)
Other income (expense):			
Affiliated interest income	168	155	137
Other	8	4	(28)
Total other income	176	159	109
Interest and related charges:			
Affiliated interest expense	60	69	73
Other	403	376	408
Total interest and related charges	463	445	481
Loss before income taxes	(299)	(291)	(404)
Income tax benefit	142	160	163
Equity in earnings of subsidiaries	1,185	1,395	1,201
Income from continuing operations	1,028	1,264	960
Income (loss) from discontinued operations (net of income tax expense of $3, benefit of $4 and expense of $15 in 2005, 2004 and 2003, respectively)	5	(15)	(642)
Net Income	$ 1,033	$ 1,249	$ 318

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

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Dominion Resources, Inc. (Parent Company)

Schedule I Condensed Financial Information of Registrant

Condensed Balance Sheets

At December 31, (millions)	2005	2004
ASSETS		
Current Assets		
Cash and cash equivalents	$ 19	$ 10
Receivables and advances due from affiliates	3,043	2,858
Other accounts receivable	14	7
Other	72	
Total current assets	3,148	2,875
Investments		
Investment in affiliates	14,664	14,474
Loans to affiliates	1,645	1,645
Other	39	39
Total investments	16,348	16,158
Deferred Charges and Other Assets	208	128
Total assets	$ 19,704	$ 19,161
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Securities due within one year	$ 513	$ 1,090
Short-term debt	497	306
Payables due to affiliates	16	16
Accrued interest and taxes	124	129
Other	85	39
Total current liabilities	1,235	1,580
Long-Term Debt		
Long-term debt	7,067	5,284
Notes payable to affiliates	817	822
Total long-term debt	7,884	6,106
Deferred Credits and Other Liabilities	188	49
Total liabilities	9,307	7,735
Common Shareholders Equity		
Common stock, no par[1]	11,286	10,888
Other paid-in capital	125	92
Retained earnings	1,550	1,442
Accumulated other comprehensive loss	(2,564)	(996)
Total common shareholders equity	10,397	11,426
Total liabilities and shareholders equity	$ 19,704	$ 19,161

(1) 500 million shares authorized; 347 million shares and 340 million shares outstanding at December 31, 2005 and 2004, respectively.

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

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Dominion Resources, Inc. (Parent Company)

Schedule I Condensed Financial Information of Registrant

Condensed Statements of Cash Flows

Year Ended December 31, (millions)	2005	2004	2003
Net Cash Provided By Operating Activities	$ 807	$ 754	$ 690
Investing Activities			
Investment in affiliates		(527)	(77)
Affiliate (advances) repayments, net	(1,654)	64	(1,296)
Loans to affiliates			(220)
Purchase of Dominion Fiber Ventures senior notes			(633)
Escrow release for debt refunding			500
Net cash used in investing activities	(1,654)	(463)	(1,726)
Financing Activities			
Issuance of common stock	664	839	990
Repurchase of common stock	(276)		
Issuance of long-term debt	2,300	300	2,120
Repayment of long-term debt	(1,090)	(268)	(1,500)
Issuance (repayment) of short-term debt, net	191	(267)	219
Repayment of short-term borrowings from affiliates, net		(24)	
Repayment of notes payable to affiliates			(15)
Common dividends paid	(923)	(861)	(825)
Other	(10)	(9)	(18)
Net cash provided by (used in) financing activities	856	(290)	971
Increase (decrease) in cash and cash equivalents	9	1	(65)
Cash and cash equivalents at beginning of the year	10	9	74
Cash and cash equivalents at end of the year	$ 19	$ 10	$ 9
Supplemental Cash Flow Information:			
Noncash investing and financing activities:			
Conversion of short-term advances and other amounts receivable from subsidiaries to investment in subsidiaries	$ 1,689	$ 84	$ 1,220
Return of preferred stock from beneficially owned trust		665	
Forgiveness of Dominion Fiber Ventures, LLC notes receivable		644	
Conversion of interest receivable from subsidiaries to long-term note receivable			125
Exchange of debt securities		219	500

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

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Dominion Resources, Inc. (Parent Company)

Schedule I Condensed Financial Information of Registrant

Notes to Condensed Financial Statements

Note 1. Basis of Presentation

Pursuant to rules and regulations of the Securities and Exchange Commission (SEC), the unconsolidated condensed financial statements of Dominion Resources, Inc. (Dominion) do not reflect all of the information and notes normally included with financial statements prepared in accordance with accounting principles generally accepted in the United States of America. Therefore, these financial statements should be read in conjunction with the consolidated financial statements and related notes included in the 2005 Form 10-K, Part II, Item 8.

Accounting for subsidiaries We have accounted for the earnings of our subsidiaries under the equity method in the unconsolidated condensed financial statements.

Income Taxes We file a consolidated federal income tax return with our subsidiaries and participate in an intercompany tax allocation agreement. At December 31, 2005 and 2004, our Balance Sheets include current taxes receivable from affiliates of $171 million and $32 million, respectively. Under the 1935 Public Utility Holding Company Act (1935 Act), we are restricted in the amount of cash reimbursements that we may receive from our subsidiaries. In August 2005, the President of the United States signed the Energy Policy Act of 2005, which provides for the repeal of the 1935 Act in February 2006.

Note 2. Long-Term Debt

At December 31, (millions)	2005 Weighted average coupon[1]	2005	2004
Unsecured Senior and Medium-Term Notes:			
2.25% to 8.125%, due 2005 to 2010	5.13%	$ 3,212	$ 3,002
5.0% to 7.82, due 2012 to 2035[2]	5.82%	3,880	2,880
Unsecured Equity-Linked Senior Notes, 5.75% due 2008		330	330
Unsecured Convertible Senior Notes, 2.125%, due 2023[3]		220	220
		7,642	6,432
Fair value hedge valuation[4]		(29)	2
Amount due within one year	3.65%	(513)	(1,090)
Unamortized discount and premium, net		(33)	(60)
		7,067	5,284
Notes Payable Affiliates:			
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts, 7.83% to 8.4%, due 2027 to 2041	8.22%	825	825
		825	825
Fair value hedge valuation		(5)	
Amount due within one year			
Unamortized discount		(3)	(3)
		817	822
Total long-term debt		$ 7,884	$ 6,106

(1) Represents weighted-average coupon rates during 2005 for debt outstanding as of December 31, 2005.

(2) At the option of holders in August 2015, $510 million of our 5.25% senior notes due 2033 are subject to redemption at 100% of the principal amount plus accrued interest.

(3) Convertible into a combination of cash and our common stock at any time after March 31, 2004 when the average closing price of our common stock reaches $88.32 per share for a specified period. At the option of holders on December 15, 2006, December 15, 2008, December 15, 2013, or December 15, 2018, these securities are subject to redemption at 100% of the principal amount plus accrued interest. In the event of an early redemption we have the intent and ability to refinance this security under our long-term credit facilities. Accordingly, this security remains classified as long-term debt on our Consolidated Balance Sheets.

(4) Represents changes in fair value of certain fixed rate long-term debt associated with fair value hedging relationships.

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Based on the stated maturity dates rather than the early redemption dates that could be elected by the instrument holders, noted above, the scheduled principal payments of long-term debt at December 31, 2005 were as follows (in millions):

2006	2007	2008	2009	2010	Thereafter	Total
$ 513	$ 1,000	$ 730	$ 300	$ 1,000	$ 4,924	$ 8,467

Our long-term debt agreements contain customary covenants and default provisions. As of December 31, 2005, there were no events of default under those covenants.

Note 3. Guarantees, Letters of Credit and Surety Bonds

As of December 31, 2005, we had issued the following types of guarantees of behalf of third parties and our subsidiaries:

	Stated Limit	Value[1]
(millions)		
Subsidiary debt[2]	$ 1,067	$ 1,067
Commodity transactions[3]	2,508	772
Lease obligation for power generation facility[4]	898	898
Nuclear obligations[5]	355	303
Third party and equity investments[6]	37	27
Miscellaneous	231	139
Total obligations	$ 5,096	$ 3,206

(1) Represents the estimated portion of the guarantee s stated limit that is utilized as of December 31, 2005 based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by our subsidiaries, the value includes the recorded amount.

(2) Guarantees of debt of Dominion Resources Services Inc. and certain DEI and CNG subsidiaries. In the event of default by the subsidiaries, we would be obligated to repay such amounts.

(3) Guarantees related to energy marketing activities and other commodity commitments of certain subsidiaries including subsidiaries of CNG and DEI. These guarantees were provided to counterparties in order to facilitate physical and financial transactions in gas, oil, electricity, pipeline capacity, transportation and related commodities and services. If any one of these subsidiaries fails to perform or pay under the contracts and the counterparties seek performance or payment, we would be obligated to satisfy such obligation. We and our subsidiaries receive similar guarantees as collateral for credit extended to others. The value provided includes

certain guarantees that do not have stated limit amounts.

(4) Guarantee of a leasing obligation of a DEI subsidiary for the Fairless Energy power station.

(5) Guarantees related to Virginia Power s and certain DEI subsidiaries potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and includes guarantees for Virginia Power s commitment to buy nuclear fuel. Also, as part of satisfying certain Nuclear Regulatory Commission requirements concerned with ensuring adequate funding for the operations of the Millstone Power Station, we have also agreed to provide up to $150 million to a DEI subsidiary, if requested by such subsidiary, to pay

Millstone s operating expenses.

(6) Guarantees supporting third parties, equity method investees and employees affected by Hurricane Katrina.

Surety Bonds and Letters of Credit

As of December 31, 2005, we had purchased $11 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $1.5 billion. We enter into these arrangements to facilitate commercial transactions by our subsidiaries with third parties. As of December 31, 2005, no amounts had been presented for payment under the letters of credit.

Indemnifications

As part of commercial contract negotiations in the normal course of business, we may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. We are unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate us have not yet occurred or, if any such event has occurred, we have not been notified of its occurrence. However, as of December 31, 2005, management believes future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

Note 4. Dividend Restrictions

The 1935 Act and related regulations issued by the SEC impose restrictions on the transfer and receipt of funds by a registered holding company from its subsidiaries, including a general prohibition against loans or advances being made by the subsidiaries to benefit the registered holding company. Under the 1935 Act, registered holding companies and their subsidiaries may pay dividends only from retained earnings, unless the SEC specifically authorizes payments from other capital accounts. We received dividends from our consolidated subsidiaries in the amounts of $1.2 billion, $1.2 billion, and $1.1 billion for the years 2005, 2004, and 2003, respectively. In response to a Dominion request, the SEC granted relief in 2000, authorizing payment of dividends by CNG from other capital accounts to Dominion in amounts of up to $1.6 billion, representing CNG s retained earnings prior to our acquisition of CNG. The SEC granted further relief in 2004, authorizing our nonutility subsidiaries to pay dividends out of capital or unearned surplus in situations where such subsidiary has received excess cash from an asset sale, engaged in a restructuring, or is returning capital to an associate company. Our ability to pay dividends on our common stock at declared rates was not impacted by the restrictions discussed above during 2005, 2004 and 2003. We are not bound by the foregoing restrictions on dividends imposed by the 1935 Act as of February 8, 2006, the effective date on which such Act was repealed under the Energy Policy Act of 2005.

The Virginia State Corporation Commission (Virginia Commission) may prohibit any public service company, including Virginia Power, from declaring or paying a dividend to an affiliate, if found not to be in the public interest. At December 31, 2005, 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 debt to total capitalization. These limitations did not restrict our ability to pay dividends or receive dividends from our subsidiaries at December 31, 2005.

See Note 18 to our Consolidated Financial Statements included in the 2005 Form 10-K, Part II, Item 8., 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.

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Signatures

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

DOMINION RESOURCES, INC.

By: /s/ THOMAS F. FARRELL, II

(Thomas F. Farrell, II, President and Chief Executive Officer)

Date: March 2, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 2nd day of March, 2006.

Signature	Title
/s/ THOS. E. CAPPS **Thos. E. Capps**	Chairman of the Board of Directors
/s/ PETER W. BROWN **Peter W. Brown**	Director
/s/ RONALD J. CALISE **Ronald J. Calise**	Director
/s/ GEORGE A. DAVIDSON, JR. **George A. Davidson, Jr.**	Director
/s/ THOMAS F. FARRELL, II **Thomas F. Farrell, II**	Director, President and Chief Executive Officer
/s/ JOHN W. HARRIS **John W. Harris**	Director
/s/ ROBERT S. JEPSON, JR. **Robert S. Jepson, Jr.**	Director

/s/ Mark J. Kington	Director
Mark J. Kington	
/s/ Benjamin J. Lambert, III	Director
Benjamin J. Lambert, III	
/s/ Richard L. Leatherwood	Director
Richard L. Leatherwood	
/s/ Margaret A. McKenna	Director
Margaret A. McKenna	
/s/ Frank S. Royal	Director
Frank S. Royal	
/s/ S. Dallas Simmons	Director
S. Dallas Simmons	
/s/ David A. Wollard	Director
David A. Wollard	
/s/ Thomas N. Chewning	Executive Vice President and Chief Financial Officer
Thomas N. Chewning	
/s/ Steven A. Rogers	Vice President, Controller and Principal Accounting Officer
Steven A. Rogers	