There's more to this light switch than meets the eye.
Behind it is an entire company.

Dominion®
It all starts here.®

2008 Summary Annual Report

Ever wonder how it happens? And who is behind it? Several generations of dedicated professionals—that is who.

Thanks to generations of great work, our electric utility franchise is celebrating its 100th birthday in 2009. We are proud of the accomplishment. We reached that milestone by navigating good economic times and bad.

You do not reach the age of 100 by taking uncalculated risks. Or by embracing bad ideas that are popular in a given moment in time. Or by abandoning the core values that have taken you so far.

We look out for customers like a lifelong friend. Dependable service is a given. Helpful programs to manage energy use and costs are at the ready, as are smiling faces or friendly voices on the phone.

We have been dependable for our investors, too, paying out more than 300 consecutive dividends. Nurturing trust with our investors. Delivering promised outcomes.

Dependability is fundamental at Dominion.

Contents


Dominion


ENERGY MATTERS

Today's economy poses big economic and financial challenges for all companies.

Fortunately, we have dedicated employees and an outstanding business platform. We have the good fortune to serve a region historically shown to be economically durable and resilient.

Our ability to create and deliver electric power and natural gas efficiently, safely and cleanly is a major asset.

As a result, we set earnings and dividend growth targets that we believe are realistic while maintaining our financial strength. Topping our agenda are controlling energy costs, investing to protect the environment, promoting renewable energy and helping the nation obtain energy independence.

We are committed to doing our share—and more—to help our region and the nation meet their energy challenges.

Flip a light switch, turn a heating knob. Easy, right?

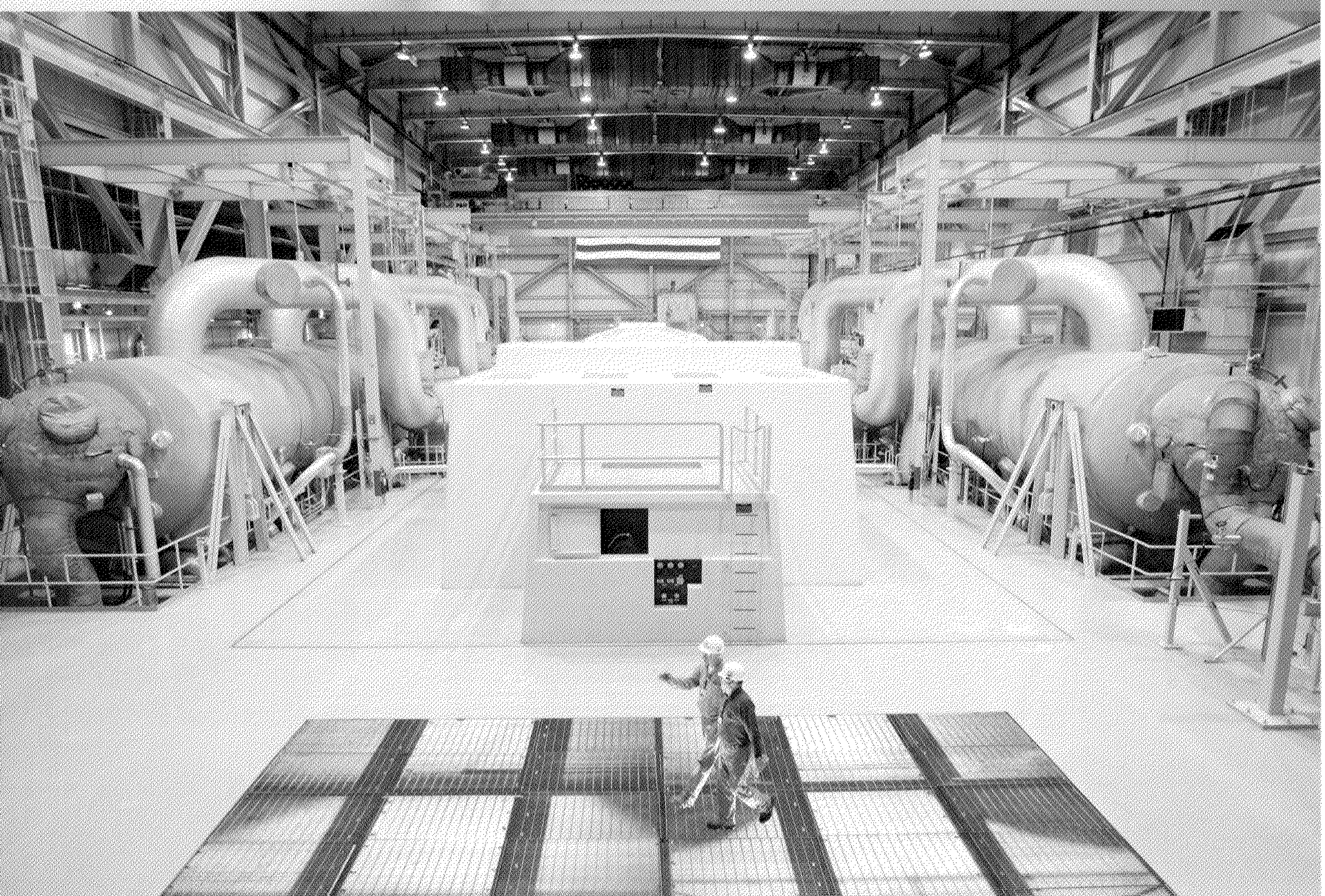
For our customers, it should be. Energy supply should seldom be on their minds. But we live it 24/7. Our dedicated and energetic work force is committed to our core values of safety, ethics, excellence and One Dominion, our term for teamwork.

In safety, we start with one premise. No injury is acceptable. Our "zero tolerance" approach produced our fifth consecutive year of improvement in 2008.

We strive for high ethical standards in all that we do. We owe it to each other. We owe it to our customers, our investors, our regulators and many other stakeholders.

Excellence starts with an attitude, takes shape through action, and ends with superior results. We are among the nation's safest and most efficient producers of energy. We maintain high levels of reliability for retail customers who depend on it. And we adhere to equally high standards at our wholesale energy transportation businesses.

In 2008, we had a great operational year. We have set ambitious goals for 2009. With continued teamwork, we are poised and ready for the next step.





So what is next?

For starters, we are making investments in a broad range of energy technologies, fuel sources and needed new production, transportation and distribution facilities. This includes emissions-free nuclear and wind power, clean-coal technology, natural gas and energy efficiency.

Even in slower economic times, the nation needs and uses energy. In our service areas, we are still at work. Installing new meters. Laying new pipes and wires. Building new generation. Moving large volumes of natural gas.

We are aggressively promoting energy efficiency and teaching our customers and the general public how to manage their consumption.

We are helping customers purchase millions of compact fluorescent light bulbs. And we began offering customers a "green power" choice to offset their carbon footprints.

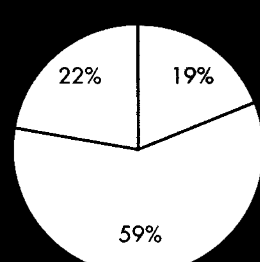
As always, we will remain actively committed to and engaged in our communities as volunteers, corporate philanthropists and good neighbors.

Dominion at a Glance

	Dominion Virginia Power	Dominion Generation	Dominion Energy
Operating Segment	**Dominion Virginia Power** operates regulated electric distribution and transmission franchises in much of Virginia and northeastern North Carolina, providing electric service to about 2.4 million homes and businesses in the two-state area. Dominion Retail and all customer service functions are part of this unit.	**Dominion Generation** operates the company's fleet of regulated power stations serving its electric utility franchise, as well as a merchant power fleet supplying wholesale markets in the Midwest and Northeast. Together, they account for more than 27,000 megawatts of generation.	**Dominion Energy** operates regulated natural gas distribution, transmission and storage businesses, including liquefied natural gas operations. It is also responsible for the company's Appalachian-based natural gas and oil exploration and production business and producer services. It has operations in Ohio, Pennsylvania, West Virginia, Virginia, Maryland and New York.
Business Lines	• Electric transmission • Electric distribution • Energy and related products and services in competitive retail markets	• Utility power production • Merchant power production	• Natural gas transmission • Natural gas distribution • Natural gas storage • Gas and oil exploration and production; producer services
2008 Highlights	• Connected nearly 37,000 new franchise customer accounts • Invested about $150 million in equipment upgrades and tree trimming to enhance system reliability • Received Federal Energy Regulatory Commission approval to proceed with 11 vital transmission projects • Provided discounts on 1.9 million energy-saving compact fluorescent light bulbs, bringing the total to 2.7 million since 2007	• Began constructing a 585-megawatt clean-coal facility in Southwest Virginia • Brought on-line nearly 800 megawatts of new generating capacity, including nuclear, gas and wind • Achieved nuclear capacity factor of 97.2 percent, excluding planned refueling outages • Had best-on-record equivalent forced outage rate on demand of 3.8 percent at the regulated fossil utility fleet • Had best-on-record safety performance	• Completed expansion of the Dominion Cove Point liquefied natural gas facility in southern Maryland • Continued major investment program to expand other components of a mid-Atlantic natural gas transmission and storage system • Completed a farm-out of drilling rights to more than 100,000 acres of Marcellus Shale in the Appalachian Basin • Implemented a new rate structure at Dominion East Ohio
2009 Outlook	• Maintain a superior safety record • File with Virginia State Corporation Commission a base rate increase request • Offer a "green power" choice to customers interested in carbon offsets	• Maintain a superior safety record • Continue investing in fleet environmental protection upgrades that will total more than $3.6 billion by 2015 • Continue to develop and build more than 3,900 megawatts of new generation to serve Virginia customers	• Maintain a superior safety record • Continue to market additional Marcellus Shale drilling rights • Expand Appalachian Basin transmission and gathering infrastructure

Forecasted Proportion of 2009 Primary Operating Segment Earnings*

- Dominion Virginia Power
- Dominion Generation
- Dominion Energy



*Excludes Corporate and Other segment

For factors that could cause actual results to differ from expected results, see Item 1A. Risk Factors, Forward-Looking Statements in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and Item 7A. Quantitative and Qualitative Disclosures About Market Risk in our Annual Report on Form 10-K for the year ended Dec. 31, 2008.

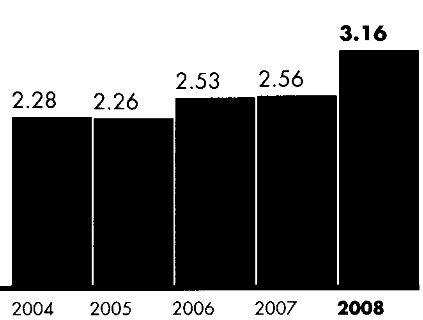
Consolidated Financial Highlights

Year Ended December 31,	2008	2007	% Change
Financial Results (millions)			
Operating revenue[1]	**$ 16,290**	$ 14,816	9.9%
Operating expenses[1] [2]	**12,664**	9,247	37.0%
Income from continuing operations	**1,836**	2,705	–32.1%
Reported earnings	**1,834**	2,539	–27.8%
Operating earnings (non-GAAP)[3]	**1,834**	1,678	9.3%
Data per Common Share			
Reported earnings	**$ 3.16**	$ 3.88	–18.6%
Operating earnings (non-GAAP)[3]	**$ 3.16**	$ 2.56	23.4%
Dividends paid	**$ 1.58**	$ 1.46	8.2%
Market value (intraday high)	**$ 48.50**	$ 49.38	–1.8%
Market value (intraday low)	**$ 31.26**	$ 39.84	–21.5%
Market value (year-end)	**$ 35.84**	$ 47.45	–24.5%
Book value (year-end)	**$ 17.28**	$ 16.31	5.9%
Market to book value (year-end)	**2.07**	2.91	–28.9%
Financial Position (millions)			
Total assets[4]	**$ 42,053**	$ 39,139	7.4%
Total debt	**17,430**	16,469	5.8%
Common shareholders' equity	**10,077**	9,406	7.1%
Equity market capitalization	**20,901**	27,369	–23.6%
Cash Flows (millions)[5]			
Net cash provided by (used in) operating activities	**$ 2,659**	$ (246)	
Net cash provided by (used in) investing activities	**(3,490)**	10,192	
Net cash provided by (used in) financing activities	**615**	(9,801)	
Other Statistics (shares in millions)			
Return on average common equity—reported	**18.8%**	22.1%	
Return on average common equity—operating[3]	**18.8%**	14.6%	
Common shares outstanding—average, diluted	**580.8**	655.2	
Common shares outstanding—year-end	**583.2**	576.8	
Number of full-time employees	**18,000**	17,000	

(1) Prior year amount has been recast to reflect our current derivative income statement classification policy.
(2) Prior year amount includes a $3.6 billion gain resulting from the sale of our U.S. non-Appalachian E&P business.
(3) Based on Non-GAAP Financial Measures. See page 30 for GAAP Reconciliations.
(4) Prior year amount has been recast to reflect the impact of adopting FSP FIN 39-1, Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts.
(5) Prior year amounts include the impact of the sale of our U.S. non-Appalachian E&P business and our debt and equity tender offers. See Liquidity and Capital Resources in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) of our 2008 Annual Report on Form 10-K for more information.

Operating Earnings Per Share*

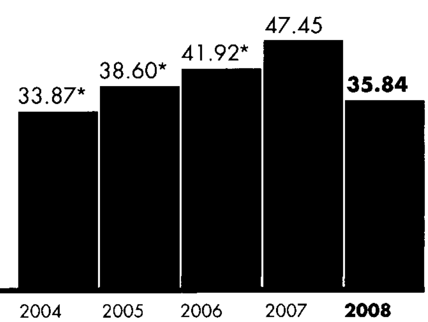
Dollars



* Based on Non-GAAP Financial Measures. See page 30 for GAAP reconciliations.

Year-end Stock Price

Dollars per Share

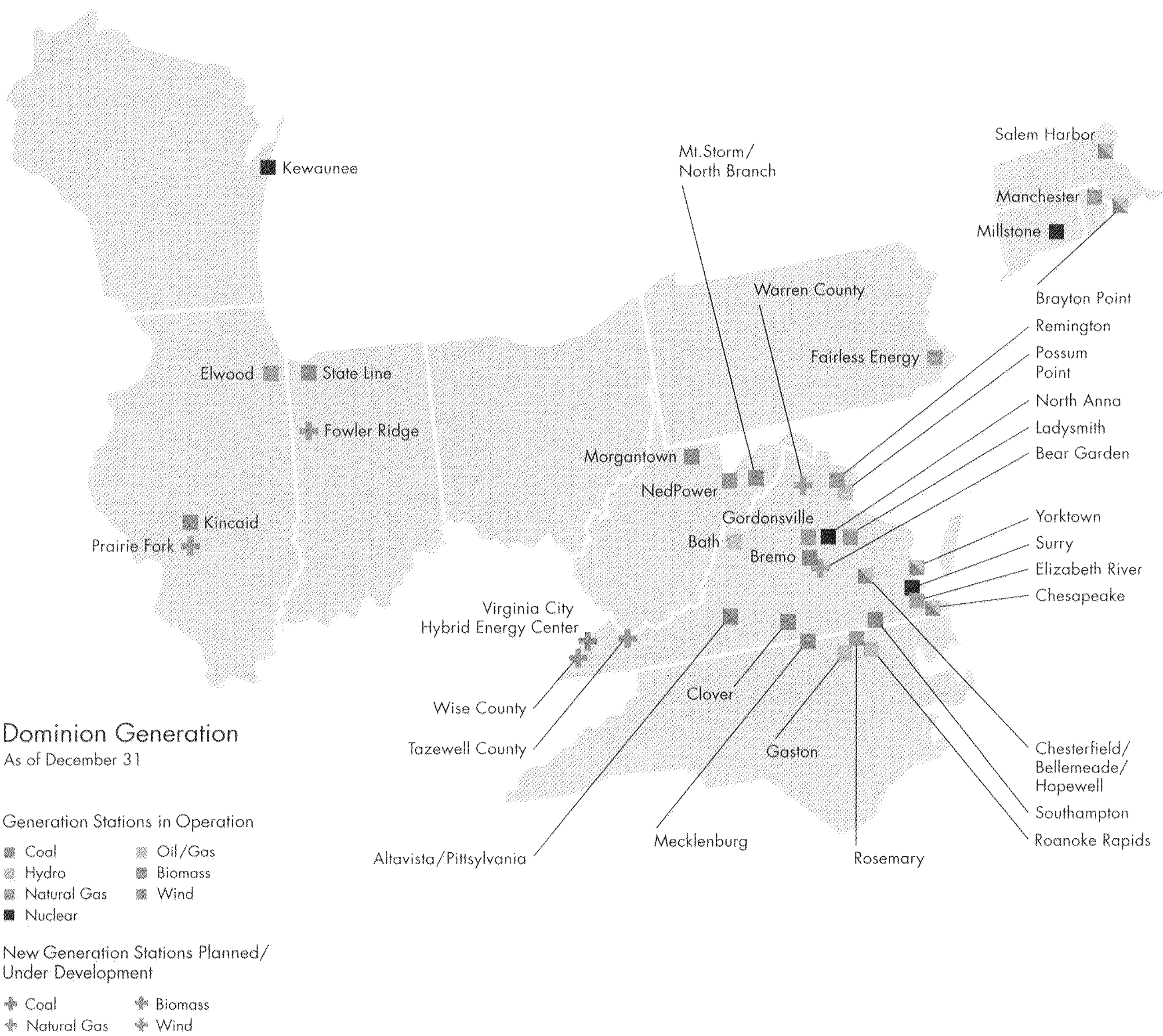


*Reflects the November 2007 2-for-1 stock split

This Summary Annual Report includes financial and operating highlights which should not be considered a substitute for our full financial statements, inclusive of footnotes and MD&A, provided to all shareholders in our 2008 Annual Report on Form 10-K. A copy of the Form 10-K, including the full financial statements, can be obtained free of charge through our Web site at www.dom.com or by writing to our Corporate Secretary at the address on the inside back cover.

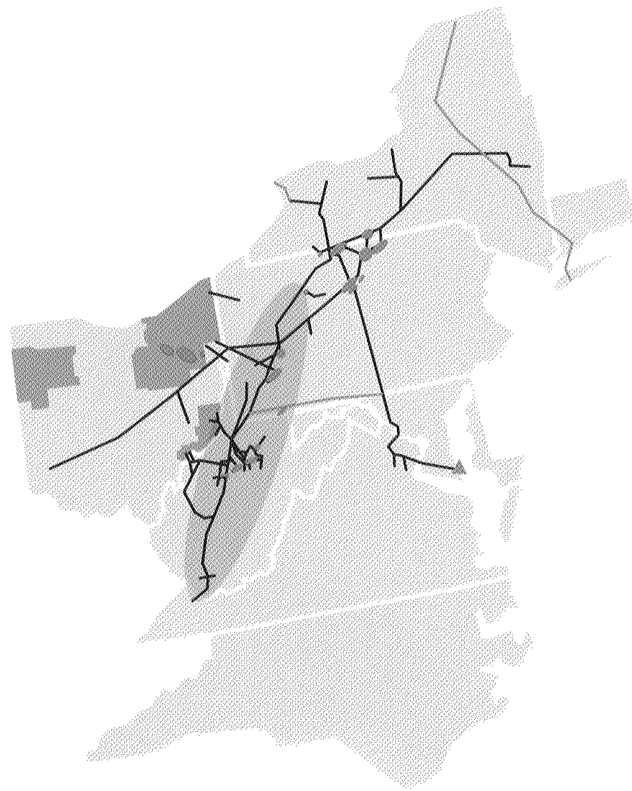
Dominion Footprint

Dominion is one of the nation's largest producers and transporters of energy, with a portfolio of more than 27,000 megawatts of generation, 1.2 trillion cubic feet equivalent of proved natural gas and oil reserves, 14,000 miles of natural gas transmission, gathering and storage pipeline and 6,000 miles of electric transmission lines. Dominion operates the nation's largest natural gas storage facility with 975 billion cubic feet of storage capacity and serves retail energy customers in 12 states. For more information about Dominion, visit the company's site at http://www.dom.com.



Dominion Energy
As of December 31

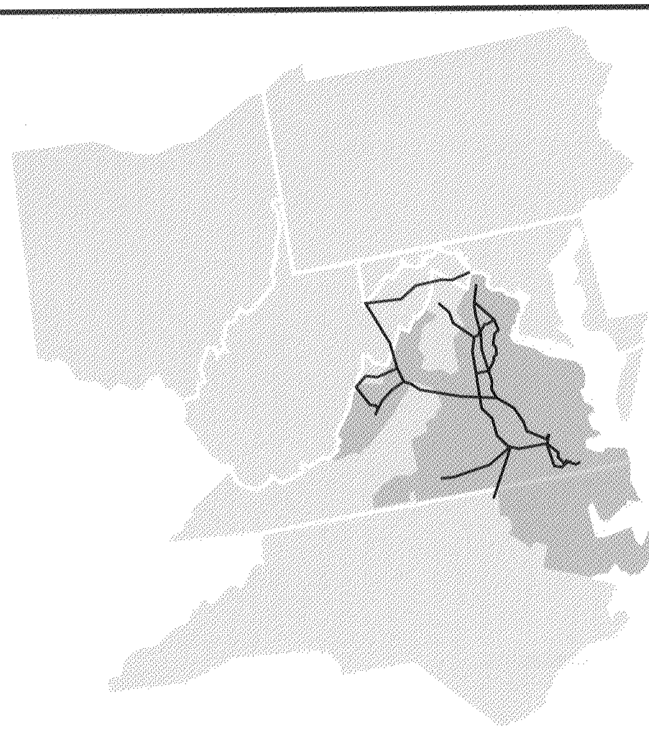
- Natural Gas Transmission Pipelines
- Natural Gas Transmission Pipelines (Partnership)
- Natural Gas Underground Storage Pools
- Cove Point LNG Facility
- Regulated Natural Gas Distribution (OH)
- E&P Producing Area



Dominion Virginia Power
As of December 31

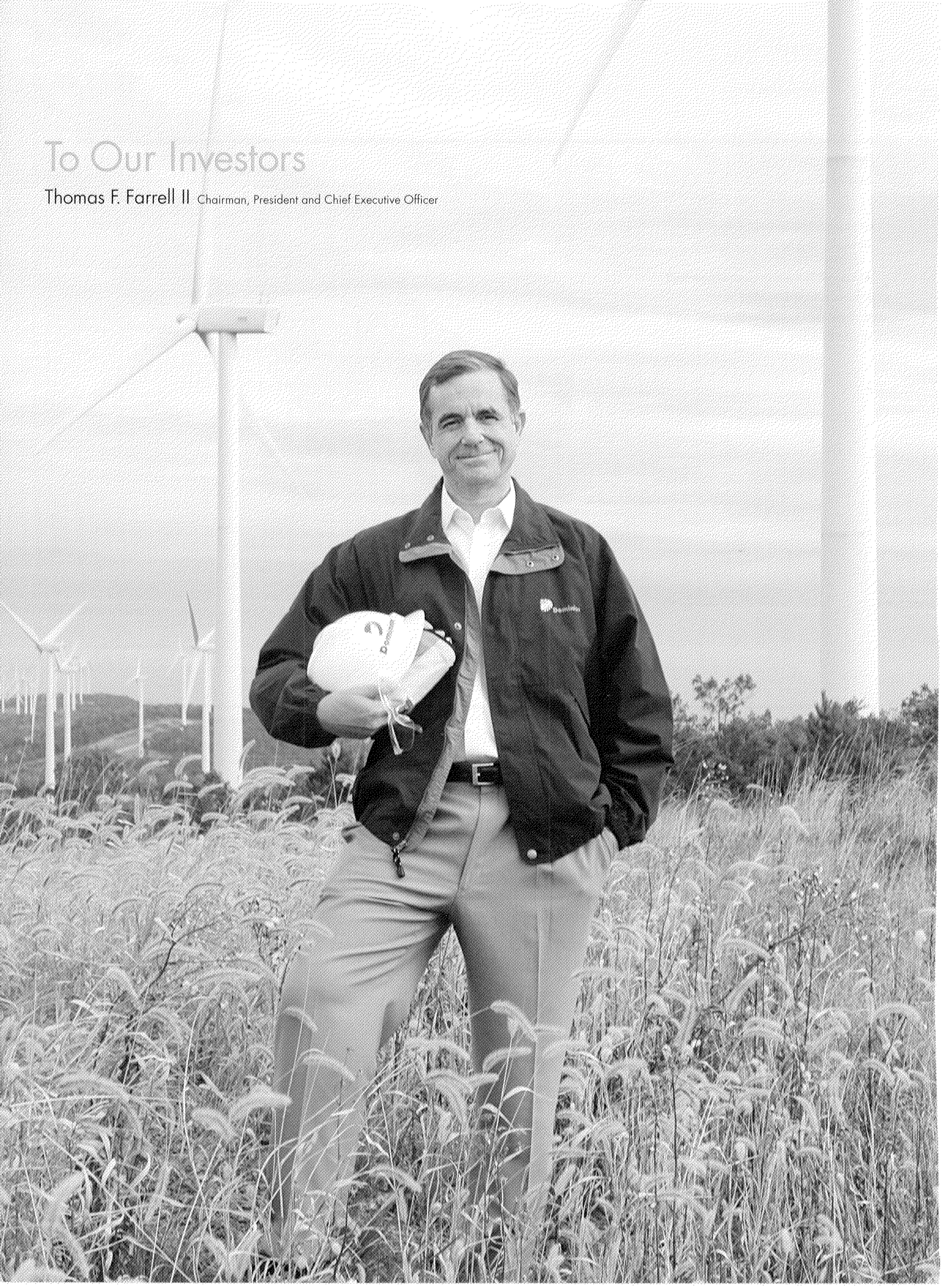
- Regulated Electric Distribution (VA) and (NC)
- Electric Transmission Lines (Bulk Delivery)

Does not reflect 1.6 million nonregulated retail customer accounts in 12 states.



To Our Investors

Thomas F. Farrell II Chairman, President and Chief Executive Officer



Run an electric power franchise for a century—yes, it is our Virginia electric utility's centennial anniversary in 2009—and you will experience good economic times and bad. The current downturn certainly qualifies as "not good," and it is definitely testing everyone. But we have witnessed recessions before and retain cause for optimism. We know our strengths; we know our abilities. We know how to enter a storm and emerge intact and ready to prosper.

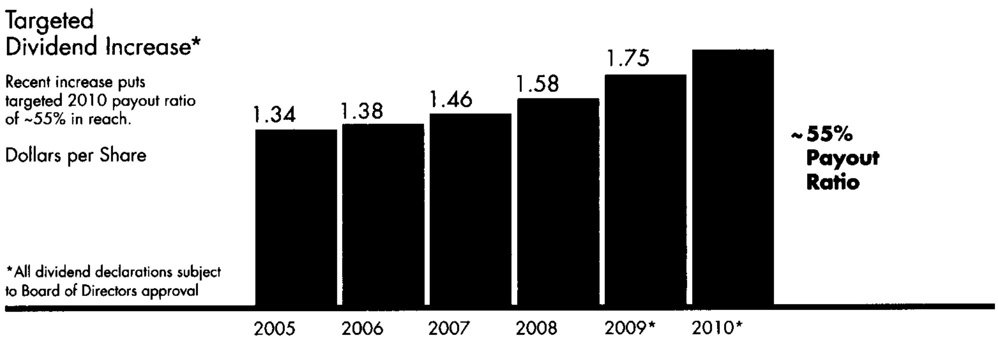
Nevertheless, we owe you a frank, realistic and level-headed assessment of our company's challenges. They include how we will access tightly restricted supplies of capital to keep modernizing our system, expand our investments in environmental protection and renewable sources of energy, and plan for long-term growth in a stalled economy—a stagnant period whose expiration date remains unknown.

An Outstanding Business Platform. We have dedicated employees, an outstanding business platform, and the good fortune of serving a region historically shown to be economically durable and resilient. Customer growth in our electric service area continues to be higher than the national average. Even now, we are installing new meters, laying new pipes and wires, building new generation, and storing and moving large volumes of natural gas to meet growing demand. Our ability to generate energy efficiently,

We have dedicated employees, an outstanding business platform, and the good fortune of serving a region historically shown to be economically durable and resilient.

safely and cleanly is an additional major advantage. Constructive state and federal regulation also facilitates activities and planned investments to modernize and expand our energy production and transportation systems.

Longtime shareholders know how we have repositioned the company to deliver stable earnings even in challenging economic times. By keeping our promise to divest ourselves of a major portion of one of our business



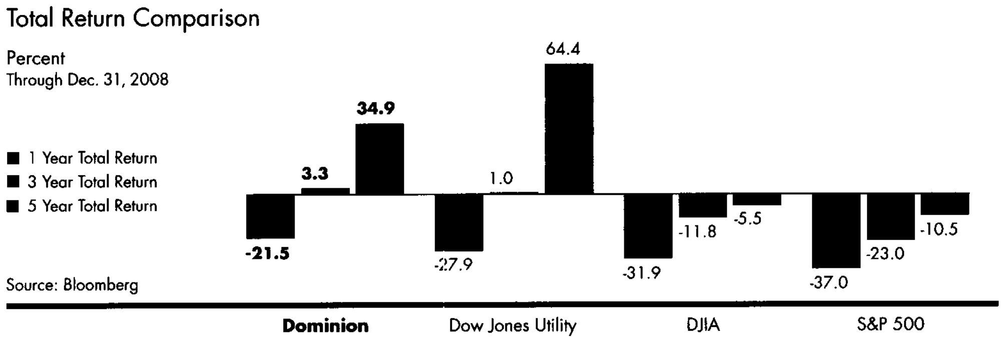
segments—a growing natural gas and oil exploration and production business (E&P)— we reduced our exposure to earnings volatility and swings in commodity prices.

By refocusing more toward utility-based infrastructure businesses while maintaining upside potential in quality market-based businesses—more than half of our operating earnings comes from our regulated electric power and natural gas companies—we have built a "regulated plus" model with the following financial goals: Earnings growth in challenging economic conditions; an increasing dividend; and strong and stable credit ratings.

Because of our current business mix—and financial and operating strength—we have maintained adequate liquidity and continued access to capital markets during the current economic crisis. Even when money is tight, we are obligated to keep our infrastructure modernization and expansion plans on track. We will not lie dormant until an economic recovery bell suddenly goes off and, only then, begin. Siting, designing, permitting and constructing a generation facility takes time and large amounts of capital. Preparing now for future growth is a responsibility that customers rely on us to carry through.

Meeting Operating Earnings, Dividend Targets. Our shareholders entrust us with the responsibility to base earnings and dividend targets on realistic assumptions and expectations.

In 2008 our operating earnings were $3.16 per share. That was slightly above the upper end of our guidance range and up 23 percent from 2007 operating earnings of $2.56 per share. Our 2008 earnings under Generally Accepted Accounting Principles (GAAP) also were $3.16 per share, down



from $3.88 per share in 2007. The 2007 results reflected one-time, after-tax gains related to the sale of our non-Appalachian E&P operations.*

In late 2008, your Board of Directors approved a nearly 11 percent increase in the common stock dividend, the second such increase in as many years, following up on a 2007 pledge to achieve a 55 percent dividend payout ratio by 2010. That would give us a ratio in line with that of our utility peers.

Holding Our Own in Fearful Markets. Like that of most other publicly traded companies, our total shareholder return suffered from market conditions in 2008 that were perhaps the worst since the Great Depression. It is worth noting, however, that Dominion's shares fared better in 2008 than both our sector and the overall stock market. At year-end, our total return was down by 21.5 percent from 2007. The Dow Jones Utility Average, a group of 15 utility stocks including Dominion, was off 27.9 percent. The Dow Jones Industrial Average dropped 31.9 percent, and the S&P 500 plunged 37.0 percent.

The credit markets were just as difficult as the equity markets.

In late 2008, we lowered previously announced 2009 operating earnings-per-share targets in deference to increased costs of capital, expected increases in pension and other benefits costs, and lower energy prices. We reduced previous 2009 operating earnings targets of $3.30-$3.45 per share to $3.20-$3.30 per share.**

* Turn to page 30 for an explanation of the differences in 2008 GAAP earnings and operating earnings.
** Management cannot estimate the impact, if any, of differences in our expected 2009 operating earnings and GAAP earnings.

Free Cash Flow Covers Operations, Maintenance—and Dividend. Revenue generated by our businesses gives us the cash needed to cover the costs of operating and maintaining them efficiently and safely. And it covers your dividend payments, as well as some of our spending for growth—an estimated $2.4 billion in 2009 and $2.0 billion in 2010, of which about 90 percent is planned for our regulated entities.

Like many businesses expanding for the long term, we plan to raise the balance of needed growth capital by accessing the debt and equity markets.

Fortunately, our financial strength and reputation give us continued access to capital markets and help ensure that we maintain adequate liquidity.

In all instances, we will access the markets in a manner that we believe will maintain our credit profile and strong liquidity position. Fortunately, our financial strength and reputation give us continued access to capital markets and help ensure that we maintain adequate liquidity.

Accessing Debt Markets, Maintaining Credit Ratings. Our access to traditional funding sources was beginning to function more normally by late 2008 and early 2009. In late 2008, for example, in two separate offerings we issued $1.3 billion of new long-term debt through our electric utility subsidiary and holding company. More than 120 institutional investors participated in each offering. While the interest rates on this debt are higher than they have been in recent years, we were pleased to demonstrate our access to markets that were largely closed to many companies. In addition, short-term markets for our commercial paper program began to act more rationally by year-end, although rates were higher than in the recent past. At no point did we ever lose access to the commercial paper markets.

Because of our continued ability to access the long-term capital markets, we ended 2008 with $2.9 billion in readily available liquidity, excluding commitments by Lehman Brothers.

Of course, our access to the capital markets depends strongly on our credit ratings. You can be assured that the company will work to maintain its solid ratings. Standard & Poor's, Fitch and Moody's rated Dominion Resources senior unsecured debt A-, BBB+ and Baa2, respectively. Each maintains a "stable" outlook on its rating. The agencies rate Virginia Electric and Power Company senior unsecured debt A-, A- and Baa1 respectively, all with stable outlooks. We manage our cash coverage ratios and balance sheet to targets that we believe will maintain these ratings over time.

Popular Stock Purchase Plans: Reliable Market for New Equity. In 2008 we issued $240 million of equity through our employee savings plans and direct stock purchase plan—including our dividend reinvestment plan—among other programs. These popular plans have historically generated about $250 million per year, thanks to continued interest by our existing shareholders in purchasing additional Dominion shares. This is an important advantage. The amounts raised through these plans are expected to offset the need for us to "time" the equity markets and issue large blocks of stock.

We still foresee the need to issue additional equity, more than half of which will be handled through the reliable annual contribution of our employee savings plans and direct stock purchase plan, for a total of $500 million in 2009 and $400 million in 2010.

You can be assured that the company will work to maintain its solid [credit] ratings.

To help with the remaining needs, we have entered into at-the-market sales agency agreements with major financial institutions that will allow the company to offer common stock from time to time during the course of those agreements. In light of Dominion's total market capitalization—about $21 billion at year-end—our planned equity issuances in 2009 and 2010 represent a relatively small amount of our equity base.

Proceeds Expected From Asset Sales. Hard cash from asset sales plays a continuing role in Dominion's management of your capital. It also helps to neutralize the need to access capital markets and issue new shares.

For example, we have used proceeds from a recent assignment of Marcellus Shale drilling rights in the Appalachian region to reduce debt balances, enabling us to issue less equity to meet our credit targets than otherwise would be required.

The company farmed out drilling rights to more than 100,000 acres of Marcellus Shale to Antero Resources for $347 million, pre-tax. In addition, we will receive a 7.5 percent royalty interest on future natural gas production from the assigned acreage.

That was only Chapter 1 of our Marcellus Shale story. Dominion has up to 800,000 acres of the formation and continues to market additional drilling rights. We have the patience and staying power to remain flexible during sour economic times. The company will enter into similar transactions only when the proposed price works effectively for you, our investor.

Also in 2008, we entered into an agreement to sell two natural gas distribution utilities—Dominion Peoples, in Pennsylvania, and Dominion Hope, in West Virginia. We expect to complete the transaction later this year and use expected after-tax proceeds to reduce outstanding debt.

Our *Regulated Plus* Model. Earlier I used the term "regulated plus" to describe how investors benefit from our business model.

As owners of an efficient electric power utility serving one of the nation's most economically durable regions, we hold a core competitive asset. Our authorized returns are established under constructive state regulation by the Virginia State Corporation Commission (SCC) and the North Carolina Utilities Commission. I will describe Virginia regulation later.

Dominion Energy is our growing platform of natural gas production, transmission and storage businesses serving the gas-intensive Northeast regions. The mid-stream pipeline and storage assets generate returns set by the Federal Energy Regulatory Commission (FERC). Dominion Energy also operates Dominion East Ohio, a natural gas distribution utility with its own complementary gathering, transmission and storage, regulated by the Public Utilities Commission of Ohio.

Our *Plusses.* The first "plus" is a merchant generation platform that is part of our Dominion Generation business unit. With over 9,000 megawatts of fuel-diverse generating capacity, compared with more than 18,000 megawatts in our utility fleet, our merchant business gives us the opportunity to take our skills as electric power generators into the Midwest and Northeast regions. In the Northeast, competitive wholesale market prices are set by competitive bidding and are generally higher than those in the Southeast. We have invested to acquire and modernize older stations, bring them to 21st-century environmental standards, and ensure that they create power efficiently.

Our merchant generation fleet is anchored by the largest nuclear power station in New England, Millstone Power Station in Connecticut, but it also includes stations fueled by coal, natural gas, oil and wind. In addition to fuel diversity, we have geographic diversity and exposure to different pricing levels in different wholesale markets. Our sales do not depend on a limited number of sites, technologies or fuel sources, a flexibility that gives our company a distinct advantage.

Our sales do not depend on a limited number of sites, technologies or fuel sources, a flexibility that gives our company a distinct advantage.

Within our Dominion Virginia Power operating unit is another plus, Dominion Retail. One of the largest competitive mass-market retail energy companies in the U.S., Dominion Retail provides natural gas and electricity—as well as home warranty and protection products and services—to 1.6 million customer accounts in 12 states where such competitive marketing is allowed by law.

Dominion Energy's plusses include Appalachian E&P, with its more than 9,000 producing wells and 1.2 trillion cubic feet equivalent of proved reserves, and Producer Services, which helps independent producers get their natural gas supplies to market.

Strong Service Area in Virginia Has Unique Characteristics. Earlier I said we had the good fortune to serve an economically durable service area in Virginia.

According to the latest independent projections, the Commonwealth is expected to need more than 4,000 megawatts of new power supply over the next decade—enough to power 1 million new homes and businesses.

Demographics explain why, beginning with Virginia's extraordinary military infrastructure. Base closures and reassignments around the U.S. have resulted in more military personnel being shifted to Virginia. Growth in personnel stationed at two major military facilities, Fort Lee in the Richmond area and Fort Belvoir in Northern Virginia, for example, will create significant new demand.

Virginia law allows your company to apply to recover the financing costs of qualified generation facilities as they are incurred—a critical consideration for investors looking for timely cost recovery.

Virginia is also a global hub of Internet activity, with more than 50 percent of the nation's Web traffic flowing through 36 data centers in Northern Virginia. These centers require a great deal of power—each the equivalent of nearly 9,000 average household customers. More than a dozen additional data centers are on the drawing board.

We also have lower exposure than our utility peers to the reduced electricity consumption expected this year from energy-intensive industrial users. About 12 percent of our sales came from industrial customers in 2008.

Constructive Utility Regulation in Virginia. Equally important to our outlook is the constructive nature of Virginia's utility regulation.

Under laws enacted in 2007, Virginia Power is now able to fully recover the costs of natural gas, coal, uranium and other fuels used in power facilities. Projected fuel costs can be passed through to customers dollar-for-dollar in rates. Provided regulators concur that the fuel costs were incurred prudently, any under-recovery can be collected in subsequent years. Estimated costs of our purchased power supply are also included in our projected fuel costs. Prior to this change in law, Dominion shareholders absorbed nearly $2 billion of unrecoverable fuel costs, pre-tax, between 2004 and 2007.

At the same time, we aggressively attempt to minimize the impact of higher fuel costs on our customers. We voluntarily worked with state regulators to hold the increase on residential customer rates last July to 18 percent, the equivalent of an additional $16.61 per month for a typical residential household, and agreed to defer additional recovery to subsequent years.

Entering 2009, we were preparing to file with the SCC to recover the costs of our modernization and expansion, and to establish returns on equity consistent with existing state law.

As we embark on an era of new construction, Virginia law allows your company to apply to recover the financing costs of qualified generation facilities as they are incurred—a critical consideration for investors looking for timely cost recovery.

The regulatory framework establishes incentives for constructing nuclear, advanced-technology coal, natural gas facilities, renewable-powered facilities, and for meeting or exceeding renewable generation goals. It also can provide reward for efficient operations that reduce costs, enable cost-effective power production and provide excellent customer service.

In addition, Virginia law ensures the opportunity to earn a competitive return on equity. The law establishes a "floor"—the SCC must allow an authorized return on equity no lower than the average earned by a peer group of utilities in the Southeast.

***Powering Virginia* Moves Ahead as Planned.** The new laws will facilitate a plan I described last year, "Powering Virginia," our program to meet the electricity needs of our customers in Virginia and northeast North Carolina. We are building it on a foundation of energy efficiency, new electric generation fueled by diverse sources, and investments in transmission and distribution projects. We strive to maintain a diverse mix of fuel sources for generation, both as a natural commodity hedge for investors and as a way to protect customers from swings in commodity prices.

Energy Efficiency: Dominion Virginia Power has provided discounts on 2.7 million energy-saving compact fluorescent light bulbs (CFLs) since 2007. During their lifetimes, these CFLs will have reduced energy consumption by 745 million kilowatt-hours and will have saved customers a total of $110 million in costs, based on data from the U.S. Environmental Protection Agency. In addition, Dominion Virginia Power has begun offering our customers a "green power" choice to offset some or all of the carbon dioxide produced in the generation of their electricity.

Coal Generation: Last year we began constructing a 585-megawatt clean-coal facility in Southwest Virginia known as the Virginia City Hybrid Energy Center. The $1.8 billion station is expected to be one of the cleanest coal-burning generating facilities in the nation and to use renewable wood biomass for at least 10 percent of its fuel.

Natural Gas Generation: In 2008 we began developing Bear Garden, a 590-megawatt natural gas-fired facility, estimated to cost about $620 million. Commercial operation is expected in 2011. A second natural-gas fired station in Warren County, Va., is in project development. Last year also saw more than 300 megawatts of new generation come on-line at our Ladysmith Power Station. Another 150 megawatts are expected at Ladysmith in 2009. We have also announced plans to convert the Bremo Power Station from coal to natural gas, subject to our hybrid energy center in Southwest Virginia entering service as planned and our receiving the necessary approvals. Such a conversion would help to reduce air emissions even further.

Nuclear Generation: Management continues to assess the economic viability of constructing another reactor unit at our North Anna Power Station. We have filed an application with federal regulators to build and operate another unit and have applied for a federal loan guarantee to assist in the financing. The benefits of nuclear generation as a source to mitigate greenhouse gases are increasingly recognized by leading environmental groups.

Renewable Generation: With BP Wind Energy North America, we are jointly pursuing sites for wind energy projects in Virginia, particularly in Tazewell and Wise counties, located in the southwestern part of the state. Later, I will describe Dominion's efforts to grow its renewable energy production outside Virginia.

Transmission and Distribution: To maintain system reliability and support future growth, we received FERC approval for an enhanced return on 11 vital transmission projects totaling nearly $900 million. To further ensure and improve system reliability, Dominion Virginia Power last year spent about $150 million on preventive maintenance, large cable replacement, tree-trimming and circuit-reconditioning programs.

We strive to maintain a diverse mix of fuel sources for generation, both as a natural commodity hedge for investors and as a way to protect customers from swings in commodity prices.

Sustaining Operating Excellence at Our Merchant Fleet. Dominion electric generation facilities share specific characteristics, regardless of location: They are extremely safe; compliant with all local, state and federal regulations; and clean, efficient and economic. Likewise, embedded in our company culture is the spirit of being a good neighbor. Our employees are committed to excellence and deeply engaged in their communities.

We are growing our merchant fleet by boosting the capacity of individual units through investments in "uprates." An uprate is the most economical way to add generating capacity, and it also provides more output with no corresponding adverse impact on safety or emissions. Our company expects to increase the overall capacity of our merchant fleet by 1 percent over the next three years through uprates projected to total about 100 megawatts.

Dominion Energy Expanding Mid-Atlantic Natural Gas Storage, Transmission. Because natural gas can be burned efficiently, reliably and cleanly, it continues to be a fuel of choice for residential and industrial consumers and electric power generators. Dominion Energy is one of the nation's leading operators of gas storage, transmission and distribution assets. Our system not only moves gas to the specific delivery points where customers request it, but it also stores new gas supplies much like a bank for future withdrawals.

By 2015 Dominion expects to have spent more than $3.6 billion on environmental improvements in its merchant and utility generating fleet.

As promised, Dominion Energy completed an expansion that nearly doubled the daily output and storage capacity at its Dominion Cove Point liquefied natural gas facility in Maryland. This upgrade of a valuable Dominion asset allows for more gas supply into the mid-Atlantic and Northeast. Cove Point's capacity is fully subscribed.

Major Environmental Improvements Across Dominion Fleet. By 2015 Dominion expects to have spent more than $3.6 billion on environmental improvements in its merchant and utility generating fleet. In the large majority of our expenditures, the improvements have come as the result of voluntary discussions and negotiations with federal and state regulators. In all cases we meet or exceed mandates.

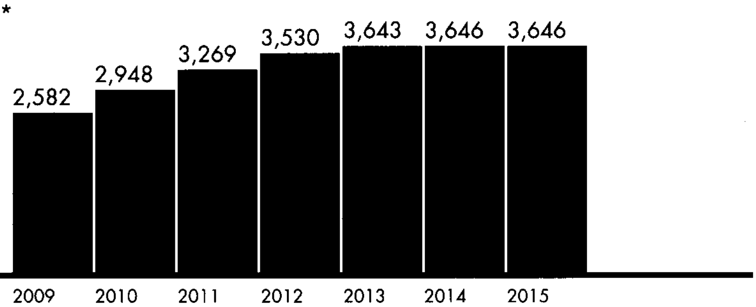
In short, we believe that protecting the environment is the right thing to do.

Project Plant It!—a partnership among Dominion, the Arbor Day Foundation and some school districts—puts that belief into action by placing seedlings into the hands of 28,000 elementary school students in Virginia, Connecticut, Massachusetts and Rhode Island.

Projected Environmental Spending (Cumulative)*

$2.3 billion already spent through 2008.

Millions of Dollars



*All planned expenditures are preliminary and may be subject to regulatory and/or Board of Directors approvals.

Our Brayton Point Power Station, New England's largest fossil-fueled power station, also defines our commitment to the environment and to the conservation of natural resources. Brayton Point is putting into place emissions and water usage controls that will benefit Massachusetts and Rhode Island.

We are building two cooling towers at Brayton Point scheduled to be operational by 2012. They are designed to reduce the station's thermal impact on Mount Hope Bay and reduce cooling water use by more than 90 percent. In addition, pollution-control equipment was installed for two coal-burning units. This equipment is designed to reduce emissions of sulfur dioxide—a cause of acid rain—by about 90 percent. A scrubber for a third coal unit is expected to be in operation by 2014.

These expenditures bring overall investment in air and water environmental improvements at Brayton to more than $1 billion.

We also entered a long-term agreement with the Illinois Environmental Protection Agency to further reduce sulfur dioxide and nitrogen oxides

Our efforts to harness cleaner, greener power through wind turbines forged ahead in 2008.

emissions at our coal-fired, 1,158-megawatt Kincaid Power Station. This demonstrates our belief that we can find solutions to issues by confronting them in a constructive manner.

Cleaner Air in Virginia. In 2008 we began operating a new scrubber at our Chesterfield Power Station in Central Virginia, continuing the state's move toward cleaner air. The equipment removes more than 95 percent of sulfur dioxide emissions and more than 90 percent of mercury emissions from the company's largest coal-fired generating unit.

This scrubber is the latest, but not the last, chapter in Dominion's long history of environmental stewardship. Dominion is building another scrubber to clean the emissions on the other three coal units at Chesterfield. That scrubber is expected to be operational in 2011.

By 2015 Dominion is expected to have spent $2.25 billion on environmental projects at power stations generating electricity for Virginia, including $920 million at Chesterfield. Deep reductions are expected—

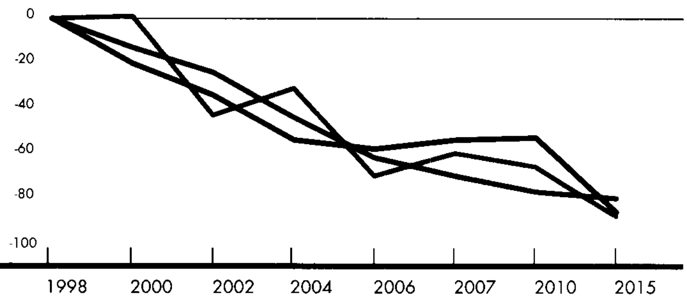
Cleaner Air in New England

Projected
emissions reduction

Percent

Dominion began ownership of Dominion New England (Brayton Point, Manchester Street and Salem Harbor Power Stations) Jan. 1, 2005

- SO_2 -86%
- NOx -80%
- Mercury -88%

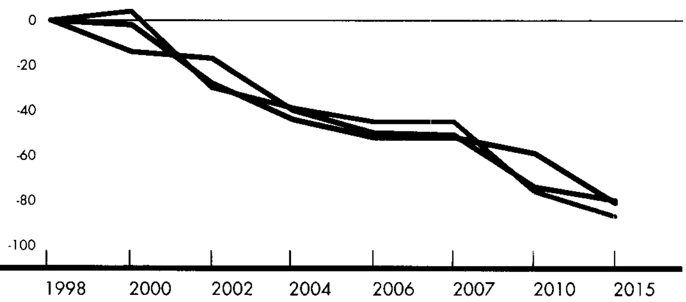


Cleaner Air in Virginia

Projected
emissions reduction

Percent

- SO_2 -81%
- NOx -80%
- Mercury -87%



80 percent or more—in mercury, sulfur dioxide and nitrogen oxides emissions. The company is also investing in technologies that would reduce carbon emissions. Dominion is a partner with Virginia Tech to demonstrate the feasibility of storing carbon dioxide in unminable coal seams at a site near our Virginia City Hybrid Energy Center.

Increasing Renewable Generation. Our efforts to harness cleaner, greener power through wind turbines forged ahead in 2008. As I told you last year, our company plans to achieve Virginia's goal of having 12 percent of base-year electricity sales coming from renewable energy by 2022 and to attain a similar goal in North Carolina.

Your company overall has about 1,300 megawatts of renewable energy from hydro, biomass and wind under development or in operation. In West Virginia, we recently completed a wind farm with Shell WindEnergy Inc. In Indiana, we are working with BP Alternative Energy North America on that state's largest wind energy project. The first phase went into commercial operation in early 2009. Dominion is also in the early stages of development for a wind project in Central Illinois. That project could produce 300 megawatts of clean electricity.

Earlier I discussed our plan to pursue wind farms in Virginia with our partner, BP.

In West Virginia, our E&P business at Dominion Energy made industry news when it drilled a company record number of wells in the Appalachian Basin in 2008 while winning a first-place award from the state's Department of Environmental Protection. The award recognized E&P's environmental stewardship for its ability to plan, construct and cleanly restore drilling sites.

Great People, Four Core Values. We are fortunate to have the best people in the business, all of whom take great pride in doing a job superbly, and all of whom live by our company's four core values—safety, ethics, excellence and One Dominion, our term for teamwork.

We start with the premise that every accident is preventable. No injury is acceptable. Our "zero tolerance" approach produced our fifth consecutive year of improvement in 2008.

Our company will not be satisfied, however, until we are accident-free. Dominion East Ohio's superb implementation of our "Target 0" safety campaign shows it can be done. East Ohio had its first summer ever without a recordable injury under guidelines enforced by the U.S. Occupational Safety and Health Administration (OSHA). It is a remarkable achievement that sets

We start with the premise that every accident is preventable. No injury is acceptable. Our "zero tolerance" approach produced our fifth consecutive year of improvement in 2008.

the bar a little bit higher for everyone. Our E&P business in the Appalachian Basin completed 2008 with four consecutive years of no lost-time accidents. At the business unit that manages the company's generating facilities powered by fossil fuels and hydroelectric resources, our employees turned in the best safety performance on record. They reduced accidents by 45 percent, lowered the severity of incidents by 65 percent—and, in so doing, topped the previous year's record performance. Our services company reduced OSHA recordable incidents by more than 70 percent in 2008.

Efficient operations are so common at Dominion that I sometimes believe it is taken for granted. A *Platts Nucleonics Week* study published last November found that our nuclear fleet is among the most efficient in the nation. North Anna and Surry, both located in Virginia, were ranked the sixth and 10th most efficient nuclear stations, respectively, in 2007, the most recent data available. In addition, our regulated utility fossil fleet had an equivalent forced outage rate on demand of 3.8 percent in 2008, the best on record.

Electric service was available to the typical Dominion Virginia Power customer 99.977 percent of the time last year, up slightly from 2007, attributable in large part to the maintenance programs I mentioned earlier. This figure excludes outages caused by major storms.

Ethics Remains Foremost: National Recognition. A window into a company's corporate culture is the way it treats its employees.

I was pleased to learn in 2008 that our company won the highest recognition given to employers for support of employees who serve in the National Guard and Reserve, the Secretary of Defense Employer Support Freedom Award. Only 15 employers received the award in 2008, from about 2,200 nominations.

Because of his belief that our company goes above and beyond the call of duty, Mike Monfalcone, an employee in our Human Resources department and a commander in the Navy Reserve, nominated Dominion for the prestigious award. Thankfully, he has returned safely from duty in Iraq. He is one of 87 Dominion employees who have been mobilized for active duty service since Sept.11, 2001.

The Dominion Thing. We try hard to do right by our employees. They represent our first and foremost embedded strength. In almost every instance, they go the extra mile—"the Dominion thing," as Kim Lowers says. She is a manager in her 24th year with the company who volunteered for days to help the citizens and emergency responders of Suffolk, Va., when a tornado ravaged that community in spring 2008. Whether steering people away from a downed power line or completing their paperwork to reconnect power to their houses, Kim gave it her best, like so many other active employees. Throughout Dominion we are giving it our best, too.

At work, we know that the future depends on our ability to continue to execute superbly. We are working hard to make wise investments. We are committed every day to operating safely and reliably, getting the most from our business platform, maintaining high performance, and nurturing a customer-centric culture and constructive regulatory relationships.

In our communities, we do our best to support education, the environment, human services, the arts and many other philanthropic endeavors. In total, your company donated about $25 million to numerous worthy causes in 2008. More than $6 million of that amount went to our signature EnergyShare program. Since its inception in 1982, EnergyShare has raised $32 million to help people in need to heat and cool their homes.

But our community involvement is not limited to money. Dominion employees annually volunteer nearly 120,000 hours of their time to support charities and worthy causes in the regions where they live and work.

I think Kim got it right. Call it "the Dominion thing."

It takes time to build a culture like ours. I am happy that we are able to celebrate our Virginia electric utility's 100th birthday this year. In fact, our history stretches back much further than that: Dominion and its predecessor companies have been in business for more than 200 years.

Despite the current recession, the future looks bright for your company. We will continue to provide reasonably priced energy in a safe, reliable, efficient and responsible manner. I am optimistic that we will build on our 200-plus years of success because our employees bring together equal portions of ethics, ingenuity, leadership, energy, experience and skill.

On behalf of the entire Dominion team, I thank you for your continued confidence in the company.

Sincerely,

Tom Farrell

Thomas F. Farrell II Chairman, President and Chief Executive Officer

Reconciliation of Operating Earnings (non-GAAP) to Reported Earnings (GAAP)

(Millions, Except Per Share Amounts)	2004	2005	2006	2007	2008
Operating Earnings (non-GAAP)*	**$1,504**	**$ 1,557**	**$1,781**	**$1,678**	**$1,834**
Items excluded from operating earnings (after-tax):					
Net gain on sale of U.S.non- Appalachian E&P business	—	—	—	2,080	(26)
Charges related to the E&P divestitures	—	—	(5)	(506)	—
Charges related to early retirement of debt	—	—	—	(148)	—
Tax benefit (charge) related to the planned sale of Peoples and Hope	—	—	(145)	9	136
Impairment loss in nuclear decommissioning trust funds	—	—	(15)	(19)	(109)
Extraordinary item related to the reapplication of SFAS No. 71	—	—	—	(158)	—
Impairment of merchant generation assets	—	—	—	(270)	—
Income (loss) from discontinued operations	(6)	6	(150)	(8)	(2)
Termination of power purchase and sales contracts	(155)	(52)	—	(137)	—
Charges related to hurricanes	(50)	(375)	(11)	—	—
Net benefits (charges) related to exiting certain businesses	(29)	(27)	(20)	52	(23)
Other items	(15)	(76)	(55)	(34)	24
Total after-tax items	(255)	(524)	(401)	861	—
Reported Earnings (GAAP)	**$ 1,249**	**$ 1,033**	**$1,380**	**$ 2,539**	**$ 1,834**
Earnings per common share—diluted:					
Operating Earnings	**$ 2.28**	**$ 2.26**	**$ 2.53**	**$ 2.56**	**$ 3.16**
Items excluded from operating earnings	(0.39)	(0.76)	(0.57)	1.32	—
Reported Earnings	**$ 1.89**	**$ 1.50**	**$ 1.96**	**$ 3.88**	**$ 3.16**

* Dominion uses operating earnings as the primary performance measurement of its earnings outlook and results for public communications with analysts and investors. Dominion management believes operating earnings provide a more meaningful representation of the company's fundamental earnings power.

Reconciliation of Operating (non-GAAP) Return on Equity to Reported (GAAP) Return on Equity

	2007		2008	
	Millions	%	Millions	%
Common Shareholders' Equity—13 mos. average	$11,508		$9,750	
Operating Earnings—Twelve months ended*	1,678		1,834	
Return on average common equity—operating		14.6%		18.8%
Reported Earnings—Twelve months ended	2,539		1,834	
Return on average common equity—reported		22.1%		18.8%

* See Reconciliation of Operating Earnings to Reported Earnings.

Directors*

Peter W. Brown, M.D.
Physician,
Virginia Surgical Associates, P.C.

George A. Davidson, Jr.
Retired Chairman,
Dominion Resources, Inc.

Thomas F. Farrell II
Chairman, President and
Chief Executive Officer,
Dominion Resources, Inc.

John W. Harris
President and Chief Executive Officer,
Lincoln Harris LLC
(real estate consulting firm)

Robert S. Jepson, Jr.
Chairman and Chief Executive Officer,
Jepson Associates, Inc.
(private investments)

Mark J. Kington
Managing Director,
X-10 Capital Management, LLC
(investments)

Benjamin J. Lambert, III
Optometrist

Margaret A. McKenna
President,
The Wal-Mart Foundation

Frank S. Royal, M.D.
Physician

David A. Wollard
Founding Chairman of the Board,
Emeritus, Exempla Healthcare

Executive Officers*

Thomas F. Farrell II
Chairman, President and
Chief Executive Officer

Thomas N. Chewning
Executive Vice President and
Chief Financial Officer

Paul D. Koonce
Executive Vice President
Chief Executive Officer,
Dominion Energy

Mark F. McGettrick
Executive Vice President
President and Chief Executive Officer,
Dominion Generation

David A. Christian
President and Chief Nuclear Officer,
Dominion Nuclear

David A. Heacock
Senior Vice President
President and Chief Operating Officer,
Dominion Virginia Power

Robert M. Blue
Senior Vice President,
Public Policy and Corporate Communications

Mary C. Doswell
Senior Vice President,
Regulation and Integrated Planning

Steven A. Rogers
Senior Vice President and
Chief Administrative Officer
President and
Chief Administrative Officer,
Dominion Resources Services

James F. Stutts
Senior Vice President and
General Counsel

Thomas P. Wohlfarth
Senior Vice President and
Chief Accounting Officer

Carter M. Reid
Vice President,
Governance and Corporate Secretary

*As of Dec. 31, 2008

Shareholder Information

Dominion Resources Services, Inc., is the transfer agent and registrar for Dominion's common stock. Our Shareholder Services staff provides personal assistance for any inquiries Monday through Friday from 9 a.m. to noon and from 1 p.m. to 4 p.m. (ET). In addition, automated information is available 24 hours a day through our voice-response system.

1 (800) 552-4034 (toll-free)
1 (804) 775-2500

Major press releases and other company information may be obtained by visiting our Web site at www.dom.com. Registered shareholders also may obtain account-specific information by visiting this site. To sign up for this service, visit www.dom.com, click "Investors" and then select "Access Your Account Online." Once you have accessed the sign-in page, click "First Time Visitor" in the upper-left corner of the screen and follow the directions for "New Member Sign Up." After you have signed up, you will be able to monitor your account, make changes and review your Dominion Activity Statements at your convenience.

Direct Stock Purchase Plan

You may buy Dominion common stock through Dominion Direct®. Please contact Shareholder Services for a prospectus and enrollment form or visit www.dom.com and click "Investors," and then select "Buy Dominion Stock Direct."

Common Stock Listing

New York Stock Exchange
Trading symbol: D

Common Stock Price Range

	2008		2007	
	High	**Low**	High	Low
First Quarter	**$48.50**	**$38.63**	$44.71	$39.84
Second Quarter	**48.28**	**41.12**	46.82	40.03
Third Quarter	**48.50**	**40.51**	46.00	40.76
Fourth Quarter	**44.46**	**31.26**	49.38	42.23
Year	**$48.50**	**$31.26**	$49.38	$39.84

Dividends on Dominion common stock are paid as declared by the board. Dominion paid 39.5 cents in each quarter of 2008. Dividends are typically paid on the 20th of March, June, September and December. Dividends can be paid by check or electronic deposit, or they may be reinvested. For more information on the dividends paid in 2008, please see Note 28 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended Dec. 31, 2008.

On Dec. 31, 2008, there were approximately 151,000 registered shareholders, including approximately 58,000 certificate holders.

Certifications

Each year, Dominion is required to submit to the New York Stock Exchange (NYSE) a certification by its chief executive officer that he is not aware of any violation by the company of NYSE corporate governance listing standards subject to any necessary qualifications. In 2008, an unqualified certification was submitted. Dominion has filed with the Securities and Exchange Commission certifications regarding the quality of the company's public disclosure by its chief executive officer and chief financial officer as Exhibits 31.1 and 31.2 in our Annual Report on Form 10-K for the year ended Dec. 31, 2008.

Annual Meeting

This year's Annual Meeting of Shareholders of Dominion Resources, Inc., will be held Tuesday, May 5, at 9:30 a.m. (ET) at 525 Arch Street, Philadelphia, Pa.

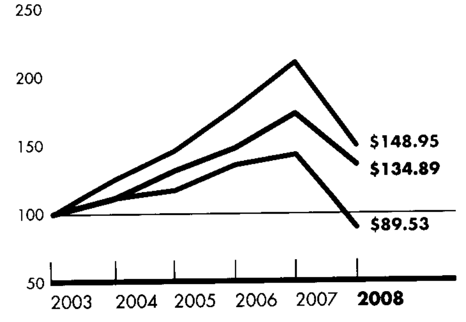
Performance Graph

This graph and table below show the five-year cumulative total return comparison between Dominion, the S&P 500 Index, and the S&P 500 Utilities Index.

Indexed Returns

	Base Period					
Years Ending December 31	2003	2004	2005	2006	2007	**2008**
Dominion	100.00	110.50	130.58	146.97	171.92	**134.89**
S&P 500	100.00	110.88	116.33	134.70	142.10	**89.53**
S&P 500 Utilities	100.00	124.28	145.21	175.69	209.73	**148.95**

Comparison of Cumulative Five Year Total Return
Dollars



■ Dominion
■ S&P 500
■ S&P 500 Utilities

Corporate Street Address

Dominion Resources, Inc.
120 Tredegar Street
Richmond, Virginia 23219

Mailing Address

Dominion Resources, Inc.
P.O. Box 26532
Richmond, Virginia 23261-6532

Web Site

www.dom.com

Independent Registered Public Accounting Firm

Deloitte & Touche LLP
Richmond, Virginia

Shareholder Inquiries

Shareholder.Services@dom.com
Dominion Resources Services, Inc.
Shareholder Services
P.O. Box 26532
Richmond, Virginia 23261-6532

Additional Information

Copies of Dominion's Annual Report, Proxy Statement and reports on Form 10-K, Form 10-Q and Form 8-K are available without charge. These items can be viewed by visiting www.dom.com, or requests for these items can be made by writing to:

Corporate Secretary
Dominion Resources, Inc.
P.O. Box 26532
Richmond, Virginia 23261-6532

Electronic Reports

Please visit Dominion's Investor site at www.dom.com/investors. On this site, you can view financial documents including our Annual Report and Proxy Statement.

Enjoy Our New Format:

Dominion has published its 2008 annual report to shareholders in a summary format that is also cost-effective. Many of our shareholders have told us they would prefer to see the chairman's letter and other basic information published in a smaller, easier-to-handle document. Others have told us they want only the detailed information contained in our Annual Report on Form 10-K filed with the Securities and Exchange Commission. By sending both this Summary Annual Report and a copy of our Form 10-K, we are working to serve the needs of both. View all Dominion publications at our Web site, www.dom.com.

Photo Captions:

Page 1 (clockwise from top left): Dominion's corporate headquarters in Richmond, Va. • Wayne Henry performs maintenance to power lines in Providence Forge, Va. • The Dominion Foundation made a $500,000 grant to the Science Museum of Virginia to take lessons about energy and the environment on the road, especially to schools. • The energy we produce powers some of life's most memorable moments.

Page 2: We have dedicated employees, an outstanding business platform, and the good fortune of serving a region historically shown to be economically durable and resilient.

Page 5 (top to bottom): Our residential customers know they can count on reliable electric and natural gas service. • In early 2009 we implemented a 7-percent uprate at Millstone Power Station's Unit 3, increasing the unit's output enough to power an additional 60,000 homes.

Page 6 (clockwise from top): The Cove Point expansion project included the installation of more than 160 miles of gas transmission line pipe. • Dominion Virginia Power has provided discounts on 2.7 million energy-saving compact fluorescent light bulbs since 2007. • Dominion has more than 750 megawatts of wind energy in various stages of development or in operation. The NedPower Mount Storm wind farm, which we operate with Shell WindEnergy, came on-line late in 2008.

Credits:

Design: Graphic Expression Inc, New York, New York
Printing: The Hennegan Company, Florence, Kentucky
Photography: Jim Barber, front cover; Bob Jones, Jr., page 1 (top left); Ted Kawalerski, pages 1 (bottom left and right), 2 and 5 (top); Cameron Davidson, pages 1 (top right) and 6 (bottom right); William Taufic, pages 5 (bottom) and 6 (top); Mark Mitchell, pages 6 (bottom left) and 12.

Special appreciation to the Science Museum of Virginia and to Mr. and Mrs. Frank S. Coleman of Richmond, Va.

The Forest Stewardship Council (FSC) is an international organization that brings people together to find solutions which promote responsible stewardship of the world's forests. The FSC has a set of 10 principles that define responsible forest management and address issues such as indigenous people's rights, community relations and labor rights, legal concerns, and environmental impacts surrounding forest management. Its product label allows consumers worldwide to recognize products that support the growth of responsible forest management.

Dominion Resources, Inc.

P.O. Box 26532
Richmond, Virginia 23261-6532
www.dom.com

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2008

OR

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

For the transition period from to

Commission File Number 001-08489

Dominion®

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

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

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

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

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

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

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

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

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

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

The aggregate market value of the common stock held by non-affiliates of the registrant was approximately $26.9 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, 2009, Dominion had 583,483,428 shares of common stock outstanding.

DOCUMENT INCORPORATED BY REFERENCE.

(a) Portions of the 2009 Proxy Statement are incorporated by reference in Part III.

Dominion Resources, Inc.

Glossary of Terms

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

Abbreviation or Acronym	Definition
AOCI	Accumulated other comprehensive income (loss)
AFUDC	Allowance for funds used during construction
BBIFNA	A subsidiary of Babcock & Brown Infrastructure Fund North America
bcf	Billion cubic feet
bcfe	Billion cubic feet equivalent
CDO	Collateralized debt obligation
CEO	Chief Executive Officer
CFO	Chief Financial Officer
Dallastown	Dallastown Realty
DCI	Dominion Capital, Inc.
DD&A	Depreciation, depletion and amortization expense
DEI	Dominion Energy, Inc.
DEPI	Dominion Exploration & Production, Inc.
DFS	Dominion Field Services, Inc.
DOE	Department of Energy
Dominion Direct®	A dividend reinvestment and open enrollment direct stock purchase plan
Dominion East Ohio	The East Ohio Gas Company
Dominion Retail	Dominion Retail, Inc.
Dresden	Partially-completed merchant generation facility sold in 2007
DRS	Dominion Resources Services, Inc.
DTI	Dominion Transmission, Inc.
DVP	Dominion Virginia Power operating segment
E&P	Exploration & production
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPS	Earnings per share
Equitable	Equitable Resources, Inc.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation No.
FSP	FASB Staff Position
Fitch	Fitch Ratings Ltd.
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
Gichner	Gichner, LLC
Hope	Hope Gas, Inc.
kWh	Kilowatt-hour
LNG	Liquefied natural gas
mcf	Thousand cubic feet
mcfe	Thousand cubic feet equivalent
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Moody's	Moody's Investors Service
Mw	Megawatt
mwhrs	Megawatt hours
North Anna	North Anna power station
NRC	Nuclear Regulatory Commission
ODEC	Old Dominion Electric Cooperative
Ohio Commission	Public Utilities Commission of Ohio
Peaker facilities	Collectively, the three natural gas-fired merchant generation peaking facilities sold in March 2007
Pennsylvania Commission	Pennsylvania Public Utility Commission
Peoples	The Peoples Natural Gas Company
PJM	PJM Interconnection, LLC
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on equity
RTO	Regional transmission organization
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
Standard & Poor's	Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies, Inc.
State Line	State Line power station
U.S.	United States of America
VIEs	Variable interest entities
Virginia Commission	Virginia State Corporation Commission
Virginia Power	Virginia Electric and Power Company
VPEM	Virginia Power Energy Marketing, Inc.
VPP	Volumetric production payment
West Virginia Commission	Public Service Commission of West Virginia

Item 1. Business

The Company

Dominion Resources, Inc. (Dominion), headquartered in Richmond, Virginia and incorporated in Virginia in 1983, is one of the nation's largest producers and transporters of energy. Our strategy is to be a leading provider of electricity, natural gas and related services to customers primarily in the eastern region of the U.S. Our portfolio of assets includes approximately 27,000 Mw of generation, 6,000 miles of electric transmission lines, 56,000 miles of electric distribution lines in Virginia and North Carolina, 14,000 miles of natural gas transmission, gathering and storage pipeline, 28,000 miles of gas distribution pipeline, exclusive of service lines of two inches in diameter or less, and 1.2 trillion cubic feet equivalent (Tcfe) of natural gas and oil reserves. Dominion also owns the nation's largest underground natural gas storage system and operates over 975 bcf of storage capacity and serves retail energy customers in twelve states.

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 or more 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), Dominion Energy, Inc. (DEI), Dominion Transmission, Inc. (DTI), Virginia Power Energy Marketing, Inc. (VPEM), Dominion Exploration and Production, Inc. (DEPI), The East Ohio Gas Company (Dominion East Ohio), Dominion Field Services, Inc. (DFS), Dominion Retail, Inc. (Dominion Retail) and Dominion Resources Services, Inc. (DRS). Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. As of December 31, 2008, Virginia Power served approximately 2.4 million retail customer accounts, including governmental agencies, as well as wholesale customers such as rural electric cooperatives and municipalities. DEI is involved in merchant generation, energy marketing and price risk management activities and natural gas and oil exploration and production in the Appalachian basin of the U.S. DTI operates a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, mid-Atlantic and Midwest states and is engaged in the production, gathering and extraction of natural gas in the Appalachian basin. VPEM provides fuel, gas supply management and price risk management services to other Dominion affiliates and engages in energy trading activities. DEPI explores for, develops and produces natural gas and oil in the Appalachian basin of the U.S. DFS is involved in the gathering and aggregation of Appalachian natural gas supply and provides various marketing-related services to its customers. Dominion Retail markets gas, electricity and related products and services to residential and small commercial and industrial customers. As of December 31, 2008, these nonregulated retail energy marketing operations served approximately 1.6 million residential and small commercial and industrial customer accounts in the Northeast, mid-Atlantic and Midwest regions of the U.S and in Texas. DRS provides accounting, legal, finance and certain administrative and technical services to our subsidiaries. In addition, all of our officers are employees of DRS.

As of December 31, 2008, our regulated gas distribution subsidiaries, Dominion East Ohio, Peoples Natural Gas Company (Peoples) and Hope Gas, Inc. (Hope), served approximately 1.7 million residential, commercial and industrial gas sales and transportation customer accounts in Ohio, Pennsylvania and West Virginia. Of these customers, approximately 500,000 are served by Peoples and Hope, which are held for sale as discussed in *Acquisitions and Dispositions*. We also operate a liquefied natural gas (LNG) import and storage facility in Maryland.

As of December 31, 2008, we had approximately 18,000 full-time employees. Approximately 6,700 employees are subject to collective bargaining agreements.

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

Where You Can Find More Information About Dominion

We file our annual, quarterly and current reports, proxy statements and other information with the 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 to the SEC. You may also request a copy of these filings, at no cost, by writing or telephoning us at: Corporate Secretary, Dominion, 120 Tredegar Street, Richmond, Virginia 23219, Telephone (804) 819-2000. Information contained on our website is not incorporated by reference in this report.

Acquisitions and Dispositions

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

Acquisition of Pablo Energy, LLC

In February 2006, we completed the acquisition of Pablo Energy, LLC (Pablo) for approximately $92 million in cash. Pablo held producing and other properties located in the Texas Panhandle area. Following the disposition of these, and all of our other non-Appalachian E&P operations during 2007, the historical results of these operations are included in our Corporate and Other segment.

Acquisition of Kewaunee Nuclear Power Station

In July 2005, we completed the acquisition of the 556 Mw Kewaunee nuclear power station (Kewaunee), located in northeastern Wisconsin, from Wisconsin Public Service Corporation, a subsidiary of WPS Resources Corporation, and Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corporation for approximately $192 million in cash. The operations of Kewaunee are included in our Dominion Generation operating segment.

Acquisition of USGen Power Stations

In January 2005, we completed the acquisition of three fossil-fuel fired generation facilities from USGen New England, Inc. for $642 million in cash. The facilities include the 1,568 Mw Brayton Point power station (Brayton Point) in Somerset, Massachusetts; the 754 Mw Salem Harbor power station (Salem Harbor) in Salem, Massachusetts; and the 432 Mw Manchester Street power station (Manchester Street) in Providence, Rhode Island. The operations of these facilities are included in our Dominion Generation operating segment.

Assignment of Marcellus Acreage

In 2008, we completed a transaction with Antero Resources (Antero) to assign drilling rights to approximately 117,000 acres in the Marcellus Shale formation located in West Virginia and Pennsylvania. We received proceeds of approximately $347 million and recognized $4 million of associated closing costs. Under the agreement, we will receive a 7.5% overriding royalty interest on future natural gas production from the assigned acreage. We will retain the drilling rights in traditional formations both above and below the Marcellus Shale interval and will continue our conventional drilling program on the acreage.

Sale of E&P Properties

In 2007, we completed the sale of our non-Appalachian natural gas and oil E&P operations and assets for approximately $13.9 billion. A more detailed description of the disposition can be found in Note 5 to our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

In 2006, we received approximately $393 million of proceeds from sales of certain gas and oil properties, primarily resulting from the sale of certain properties located in Texas and New Mexico and in December 2004, we sold the majority of our natural gas and oil assets in British Columbia, Canada for $476 million.

The historical results of these operations are included in our Corporate and Other segment.

Sale of Merchant Facilities

In March 2007, we sold three Peaker facilities for net cash proceeds of $254 million. The Peaker facilities included the 625 Mw Armstrong facility in Shelocta, Pennsylvania; the 600 Mw Troy facility in Luckey, Ohio; and the 313 Mw Pleasants facility in St. Mary's, West Virginia. Following our decision to sell these assets in December 2006, the results of these operations were reclassified to discontinued operations and are presented in our Corporate and Other segment.

Sale of Dresden

In September 2007, we completed the sale of the partially completed Dresden Energy merchant generation facility (Dresden) to AEP Generating Company for $85 million.

Sale of Certain Dominion Capital, Inc. (DCI) Operations

In August 2007, we completed the sale of Gichner, LLC (Gichner), all of the issued and outstanding shares of the capital stock of Gichner, Inc. (an affiliate of Gichner) and Dallastown Realty (Dallastown) for approximately $30 million.

In March 2008, we reached an agreement to sell our remaining interest in the subordinated notes of a third-party collateralized debt obligation (CDO) entity held as an investment by DCI and in April 2008 received proceeds of $54 million, including accrued interest. As discussed in Note 25 to our Consolidated Financial Statements, we deconsolidated the CDO entity as of March 31, 2008.

Planned Sales

In addition to the completed acquisitions and divestitures above, in March 2006, we entered into an agreement with Equitable to sell two of our wholly-owned regulated gas distribution subsidiaries, Peoples and Hope. Peoples and Hope serve approximately 500,000 customer accounts in Pennsylvania and West Virginia. This sale was subject to regulatory approvals in the states in which the companies operate, as well as antitrust clearance under the Hart-Scott-Rodino Act (HSR Act). In January 2008, Dominion and Equitable announced the termination of that agreement, primarily due to the continued delays in achieving final regulatory approvals. We continued to seek other offers for the purchase of these utilities.

In July 2008, we announced that we entered into an agreement with a subsidiary of Babcock & Brown Infrastructure Fund North America (BBIFNA) to sell Peoples and Hope for approximately $910 million, subject to adjustments to reflect levels of capital expenditures and changes in working capital. In September 2008, Peoples and BBIFNA filed a joint petition with the Pennsylvania Commission seeking approval of the purchase by BBIFNA of all of the stock of Peoples. In October 2008, Hope and BBIFNA filed a joint petition seeking West Virginia Commission approval of the purchase by BBIFNA of all of the stock of Hope. In September 2008, Dominion and BBIFNA each filed a Premerger Notification and Report Form with the U.S. Department of Justice (DOJ) and the Federal Trade Commission under the HSR Act. In October 2008, the waiting period under the HSR Act related to the proposed sale of Peoples and Hope to BBIFNA expired. The transaction is expected to close in 2009, subject to regulatory approvals in Pennsylvania and West Virginia as well as clearance under the Exon-Florio provision of the Omnibus Trade and Competitiveness Act. We expect to use the after-tax proceeds from the sale to reduce our debt. The results of Peoples' and Hope's operations are included in our Corporate and Other segment.

Operating Segments

We manage our daily operations through three primary operating segments: Dominion Virginia Power (DVP), Dominion Energy and Dominion Generation. We also report a Corporate and Other segment that includes our corporate, service company and other functions and the net impact of certain operations disposed of or to be disposed of, which are discussed in Note 5 to our Consolidated Financial Statements. Corporate and Other also includes specific items attributable to our operating segments, that are not included in profit measures evaluated by executive management, in assessing the segments' performance or allocating resources among the segments.

While we manage our daily operations through our operating segments as described below, our assets remain wholly-owned by our legal subsidiaries.

For additional financial information on business segments and geographic areas, including revenues from external customers, see Notes 1 and 26 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.

DVP

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

Revenue provided by our electric distribution operations is based primarily on rates established by state regulatory authorities and state law. Changes in revenue are driven primarily by weather, customer growth and other factors impacting consumption such as the economy and energy conservation. Operationally, electric distribution continues to focus on improving service levels while striving to reduce costs and link investments to operational results. As part of this continued focus, we have implemented an asset management process to ensure that we are optimizing our investments to balance cost, performance and risk. We are also using technology to enhance customer service options. As we move toward the future, safety, operational performance and customer relationships will remain as key focal areas. Variability in earnings results from changes in rates, the demand for services and operating and maintenance expenditures.

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

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

In April 2008, FERC granted an application by our electric transmission operations to establish a forward-looking formula rate mechanism that will update transmission rates on an annual basis and approved a return on equity (ROE) of 11.4% on the common equity base of these operations, effective as of January 1, 2008. The FERC ruling did not materially impact our results of operations; however, going forward the FERC-approved formula method will allow us to earn a more current return on our growing investment in electric transmission infrastructure. In addition, in August 2008, FERC granted an application by our electric transmission operations requesting a revision to our cost of service to reflect an additional ROE incentive adder for eleven electric transmission enhancement projects and approved an incentive of 1.5% for four of the projects and an incentive of 1.25% for the other seven. See *Federal Regulations* in *Regulation* for additional information.

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

Operationally, DVP continues to enhance the customer experience through solid reliability performance and by providing our customers the ability to manage their accounts on-line. At the end of 2008, over 600,000 of DVP's customers were signed up to manage their account on-line through dom.com and over 2 million transactions were performed in 2008. This reflects a transaction increase of 28% over 2007. Customers typically use the Internet for routine billing and payment transactions; however, we expect the addition of new 2008 options like connecting and disconnecting service and reporting outages and obtaining outage updates to continue to increase on-line usage.

Our retail energy marketing operations compete in nonregulated energy markets and have experienced strong growth during the past few years. The retail business requires limited capital investment and currently employs fewer than 150 people. The retail customer base is diversified across three product lines—natural gas, electricity and home warranty services. In natural gas, we have a heavy concentration of customers in markets where utilities have a long-standing commitment to customer choice. In electricity, we pursue markets where utilities have divested of generation assets and where customers are permitted and have opted to purchase from the market. Major growth drivers are customer additions, new markets/products and sales channels, and supply optimization.

Competition

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

Our retail energy marketing operations compete against incumbent utilities and other energy marketers in nonregulated energy markets for natural gas and electricity.

Regulation

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

PROPERTIES

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

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

The first project is an approximately 270-mile 500-kV transmission line that begins in southwestern Pennsylvania, crosses West Virginia, and terminates in northern Virginia, of which we will construct approximately 65 miles in Virginia (Meadow Brook-to-Loudoun line) and a subsidiary of Allegheny Energy, Inc. (Trans-Allegheny Interstate Line Company) will construct the remainder. In October 2008, the Virginia Commission authorized construction of the Meadow Brook-to-Loudoun line and affirmed the 65-mile route we proposed for the line which is adjacent to, or within, existing transmission line right-of-ways. The Virginia Commission's approval of the Meadow Brook-to-Loudoun line was conditioned on the respective state commission approvals of both the West Virginia and Pennsylvania portions of the transmission line. The West Virginia Commission's approval of Trans-Allegheny Interstate Line Company's application became effective in February 2009 and the Pennsylvania Commission granted approval in December 2008. In February 2009, Petitions for Appeal of the Virginia Commission's approval of the Meadow Brook-to-Loudoun line were filed with the Supreme Court of Virginia by the Piedmont Environmental Council and others. The Meadow Brook-to-Loudoun line is expected to cost approximately $255 million and, subject to the receipt of all regulatory approvals, is expected to be completed in June 2011.

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

In addition, DVP's electric distribution network includes approximately 56,000 miles of distribution lines, exclusive of service level lines, in Virginia and North Carolina. The grants for most of our electric lines contain right-of-ways that have been obtained from the apparent owner of real estate, but underlying titles have not been examined. Where right-of-ways have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many electric lines are on publicly-owned property, where permission to operate can be revoked.

SOURCES OF ENERGY SUPPLY

DVP's utility operations supply of electricity to serve customers is produced or procured by Dominion Generation. See *Dominion Generation* for additional information. DVP's nonregulated retail energy marketing operations supply of electricity to serve its customers is procured through market wholesalers and RTO or independent system operator (ISO) transactions and its supply of gas to serve its customers is procured through market wholesalers or by Dominion Energy. See *Dominion Energy* for additional information.

SEASONALITY

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

Dominion Energy

Dominion Energy includes our Ohio regulated natural gas distribution company, regulated gas transmission pipeline and storage operations, regulated LNG operations and our Appalachian natural gas E&P business. Dominion Energy also includes producer services, which aggregates natural gas supply, engages in natural gas trading and marketing activities and natural gas supply management and provides price risk management services to Dominion affiliates.

The gas transmission pipeline and storage business serves gas distribution businesses and other customers in the Northeast, mid-Atlantic and Midwest. Included in our gas transmission pipeline and storage business is our gas gathering and extraction activity, which sells extracted products at market rates. Revenue provided by our regulated gas transmission and storage, and LNG operations is based primarily on rates established by FERC. Our gas distribution operations serve residential, commercial and industrial gas sales and transportation customers in Ohio. Revenue provided by our gas distribution operations is based primarily on rates established by the Ohio Commission. The profitability of these businesses is dependent on our ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability in earnings results from operating and maintenance expenditures, as well as, changes in rates and the demand for services, which can be dependent on weather and changes in commodity prices.

Revenue from gas transportation, gas storage, and LNG storage and regasification services are largely based on firm, fee-based contractual arrangements. Approximately ten to twenty percent of these agreements are subject to renewal each year.

In October 2008, Dominion East Ohio implemented a rate case settlement which begins the transition to Straight Fixed Variable (SFV) rate design. Under the SFV rate design, Dominion East Ohio will recover a larger portion of its fixed operating costs through a flat monthly charge accompanied by a reduced volumetric base delivery rate. Accordingly, Dominion East Ohio's revenue will be less impacted by weather-related fluctuations in natural gas consumption than under the traditional rate design.

Our Appalachian E&P business generates income from the sale of natural gas and oil we produce from our reserves, including fixed-term overriding royalty interests formerly associated with our volumetric production payment (VPP) agreements discussed in Note 12 to our Consolidated Financial Statements. Variability in earnings relates to changes in commodity prices, which are largely market based, production volumes, which are impacted by numerous factors including drilling success and timing of development projects, and drilling costs which may be impacted by drilling rig availability and other external factors. Production from fixed-term overriding royalty interests formerly associated with our VPP agreements is expected to decline 87% in 2009, reflecting the expiration of these interests in February 2009. We manage commodity price volatility by hedging a substantial portion of our near-term expected production, which should help mitigate the adverse impact on earnings from recent declines in gas and oil prices, such as those experienced in late 2008. These hedging activities may require cash deposits to satisfy collateral requirements. Our Appalachian E&P business added 149 bcfe to its gas and oil reserves as a result of its drilling program during 2008, as compared to production of 46.9 bcfe in 2008, excluding production from fixed-term overriding royalty interests.

Earnings from Dominion Energy's other nonregulated business, producer services, are subject to variability associated with changes in commodity prices. Producer services uses physical and financial arrangements to hedge this price risk.

Competition

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

With respect to our Ohio natural gas distribution subsidiary, there has been no legislation enacted to require supplier choice for residential and commercial natural gas consumers. However, we have offered an Energy Choice program to customers, in cooperation with the Ohio Commission. See *Regulation—State Regulations—Gas* for additional information.

Regulation

Dominion Energy's natural gas transmission pipeline, storage and LNG operations are regulated primarily by FERC. Dominion Energy's gas distribution service, including the rates that it may charge customers, is regulated by the Ohio Commission. See *State Regulations* and *Federal Regulations* in *Regulation* for more information.

Properties

Dominion Energy's gas distribution network is located in the state of Ohio. This network involves approximately 18,500 miles of pipe, exclusive of service lines of two inches in diameter or less. The rights-of-way grants for many natural gas pipelines have been obtained from the actual owner of real estate, as underlying titles have been examined. Where rights-of-way have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many natural gas pipelines are on publicly-owned property, where company rights and actions are determined on a case-by-case basis, with results that range from reimbursed relocation to revocation of permission to operate.

Dominion Energy has approximately 11,890 miles of gas transmission, gathering and storage pipelines located in the states of Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. Dominion Energy operates 20 underground gas storage fields located in New York, Ohio, Pennsylvania and West Virginia, with almost 2,000 storage wells and approximately 345,600 acres of operated leaseholds.

The total designed capacity of the underground storage fields operated by Dominion Energy is approximately 942 bcf. Certain storage fields are jointly-owned and operated by Dominion Energy. The capacity of those fields owned by our partners totals about 242 bcf. Dominion Energy also has about 8 bcf of above-ground storage capacity at its Cove Point LNG facility. Dominion Energy has about 123 compressor stations with more than 706,000 installed compressor horsepower.

Dominion Energy also owns about 1.2 Tcfe of proved natural gas and oil reserves and produces approximately 128 million cubic feet equivalent of natural gas and oil per day from its leasehold acreage and facility investments in Appalachia.

In 2006, FERC approved the proposed expansion of our Cove Point terminal and DTI pipeline and the commencement of construction of such project. Such expansion included the installation of two new LNG storage tanks at our Cove Point terminal, each capable of storing 160,000 cubic meters of LNG and expansion of our Cove Point pipeline to approximately 1,800,000 dekatherms per day. In addition, our DTI gas pipeline and storage system would be expanded by building 81 miles of pipeline, two compressor stations in Pennsylvania and other upgrades.

In 2007, Washington Gas Light Company (WGL) petitioned the U.S. Court of Appeals for the District of Columbia (D.C. Appeals Court) for review of FERC's orders. Prior to FERC's final order approving the Cove Point expansion, WGL had asked FERC to delay its approval based on its assertion that leaks on its system were caused by the composition of gas received from the Cove Point pipeline. FERC rejected WGL's claims, concluding that the leaks were a result of other defects in WGL's system, not the composition of the LNG received from Cove Point. In July 2008, the D.C. Appeals Court affirmed FERC's rulings on a number of important issues, including FERC's findings that the leaks were the result of defects on WGL's system and that we are not responsible for repairs. However, the court vacated FERC's orders to the extent that these orders approved the expansion and remanded the case back to FERC so that FERC could more fully explain whether the expansion could go forward without causing unsafe leakage on WGL's system.

In an order on remand issued in October 2008, FERC responded to the D.C. Appeals Court by reissuing authorizations for the construction and operation of the Cove Point and DTI facilities. FERC also capped deliveries from the Cove Point pipeline into Columbia Gas Transmission Corporation (Columbia) at currently authorized levels. FERC took this step to ensure that WGL would not be exposed to greater deliveries of regasified LNG via Columbia than it can currently receive. This limitation on deliveries to Columbia will have no impact on Cove Point's firm service obligations. In November 2008, WGL requested rehearing of the order on remand. In an order on rehearing in January 2009, FERC upheld its decision reauthorizing construction and operation of the Cove Point LNG expansion. The DTI facilities associated with the Cove Point expansion project were placed into service in December 2008. It is anticipated that the expanded Cove Point facilities will be fully placed into service in the first quarter of 2009.

We previously entered into an agreement with Antero to assign natural gas drilling rights on approximately 205,000 Appalachian Basin net acres for approximately $552 million; however, due to Antero's difficulty in obtaining follow-on financing, the amount assigned was reduced. In September 2008, we completed a transaction with Antero to assign drilling rights to approximately 117,000 acres in the Marcellus Shale formation located in West Virginia and Pennsylvania. We received proceeds of approximately $347 million and recognized $4 million of associated closing costs. Under the agreement, we will receive a 7.5% overriding royalty interest on future natural gas production from the assigned acreage. We will retain the drilling rights in traditional formations both above and below the Marcellus Shale interval and will continue our conventional drilling program on the acreage. We control drilling rights on substantial acreage in the Marcellus Shale formation, and expect to pursue similar transactions in the future.

DTI has announced the proposed development of a gas pipeline project, known as the Appalachian Gateway Project, which is designed to transport gas on a firm basis out of the Appalachian Basin in West Virginia and southwestern Pennsylvania to DTI's interconnect with Texas Eastern Transmission Corporation at Oakford, Pennsylvania. An open season for the project concluded in September 2008. Project timing is uncertain.

We have also announced the proposed development of the Dominion Keystone Project, an expansion of the DTI system that would transport new natural gas supplies from the Appalachian Basin to markets throughout the eastern U.S. In December 2008, we terminated our agreement with Antero, under which Antero was to join DEPI as an anchor tenant of the Dominion Keystone Project. We are currently in discussions regarding the continued development of the Dominion Keystone Project. Project timing is subject to producer drilling plans in the Appalachian Basin, as well as customer demand throughout the mid-Atlantic and Northeast regions.

Sources of Energy Supply

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

Our underground storage facilities play an important part in balancing gas supply with consumer demand and are essential to serving the Northeast, mid-Atlantic and Midwest regions. In addition, storage capacity is an important element in the effective management of both gas supply and pipeline transmission capacity. Dominion Energy's natural gas supply is obtained from various sources including our own equity production, purchases from major and independent producers in the Mid-Continent and Gulf Coast regions, local producers in the Appalachian area and gas marketers.

Seasonality

Dominion Energy's natural gas distribution business earnings vary seasonally, as a result of the impact of changes in temperature on demand by residential and commercial customers for gas to meet heating needs. Historically, the majority of these earnings have been generated during the heating season, which is generally from November to March, however implementation of the SFV rate design should reduce the earnings impact of weather-related fluctuations. Demand for services at our pipelines and storage business can also be weather sensitive. Dominion Energy's Appalachian E&P business can be impacted 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 impacted by seasonal weather changes and by the effects of weather on operations. Our producer services business is affected by seasonal changes in the prices of commodities that it transports, stores and actively markets and trades.

Dominion Generation

Dominion Generation includes the generation operations of our merchant fleet and regulated electric utility, as well as energy marketing and price risk management activities for our generation assets. Our utility generation operations primarily serve the supply requirements for our DVP segment's utility customers. Our generation mix is diversified and includes coal, nuclear, gas, oil, and renewables. 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, Pennsylvania, Rhode Island, West Virginia and Wisconsin. As discussed in *Properties*, we have plans to add additional generation capacity to satisfy future growth in our utility service area. In our merchant generation business, we are adding generation capacity through several new renewable energy projects and uprates.

Dominion Generation's earnings primarily result from the sale of electricity generated by our utility and merchant assets, as well as associated capacity from our merchant generation assets. Due to 1999 Virginia deregulation legislation, as amended in 2004 and 2007, revenues for serving Virginia jurisdictional retail load were based on capped rates through 2008. Additionally, fuel costs for the utility fleet, including purchased power, were subject to fixed-rate recovery provisions until July 1, 2007. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were re-instituted beginning July 1, 2007 for our Virginia jurisdictional customers. As discussed in *Status of Electric Regulation in Virginia* under *Regulation*, the Virginia General Assembly enacted legislation in April 2007 that returned the Virginia jurisdiction of our utility generation operations to a modified cost-of-service rate model, subject to base rate caps in effect through December 31, 2008. As a result, we reapplied the provisions of SFAS No. 71 to those operations on April 4, 2007, the date the legislation was enacted. We currently anticipate that the 2009 base rate review will result in an increase in rates, however, we cannot predict the outcome of future rate actions at this time. Variability in earnings for our utility operations results from changes in rates, the demand for services, which is primarily weather dependent, and labor and benefit costs, as well as the timing, duration and costs of scheduled and unscheduled outages.

Variability in earnings provided by the merchant fleet relates to changes in market-based prices received for electricity and capacity. Market-based prices for electricity are largely dependent on commodity prices and the demand for electricity, which is primarily dependent upon weather. Capacity prices are dependent upon resource requirements in relation to the supply available (both existing and new) in the forward capacity auctions, which are held approximately three years in advance of the associated delivery year. We manage price volatility by hedging a substantial portion of our expected near-term sales with derivative instruments and also enter into long-term power sales agreements, which should help mitigate the adverse impact on earnings from recent declines in commodity prices, such as those experienced during late 2008. 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.

Competition

Retail choice was made available to our Virginia jurisdictional electric utility customers beginning January 1, 2003; however, no significant competition developed in Virginia. In April 2007, the Virginia General Assembly passed legislation ending retail choice for most of our Virginia jurisdictional electric utility customers effective January 1, 2009. See *Regulation—State Regulations—Electric* for more information. 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 that operate within functioning RTOs. A significant portion of the output from these facilities is sold under long-term contracts, with expiration dates ranging from December 31, 2012 to August 31, 2017, and is therefore largely unaffected by competition.

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

Regulation

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

Properties

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

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

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

In July 2007, we filed an application with the Virginia Commission requesting approval to construct and operate a 585 Mw (nominal) carbon capture-compatible, clean-coal powered electric generation facility (Virginia City Hybrid Energy Center) to be located in Wise County, Virginia. The Virginia Commission issued a final order in March 2008 (Final Order), approving a certificate to construct and operate the proposed Virginia City Hybrid Energy Center, granting approval for us to continue to accrue AFUDC until capped rates end and approving a rate adjustment clause, allowing us current recovery of financing costs beginning January 1, 2009, as specified in the Final Order. In its Final Order, the Virginia Commission approved an initial return on common equity for the facility of 12.12%, consisting of a base return of 11.12% plus a 100 basis point premium that Virginia law provides for new conventional coal generation facilities. The Virginia Commission also authorized us to apply for an additional 100 basis point premium upon a demonstration that the plant is carbon-capture compatible. The enhanced return will apply to the Virginia City Hybrid Energy Center during construction and through the first twelve years of the facility's service life. In July 2008, the Southern Environmental Law Center (SELC), on behalf of four environmental groups, filed a Petition for Appeal of the Final Order with the Supreme Court of Virginia. A decision is expected in April 2009.

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

We are considering the construction of a third nuclear unit at a site located at North Anna power station (North Anna), which we own along with Old Dominion Electric Cooperative (ODEC). In November 2007, the NRC issued an Early Site Permit (ESP) to our subsidiary, Dominion Nuclear North Anna, LLC (DNNA). Also in November 2007, we, along with ODEC, filed an application with the NRC for a Combined Construction Permit and Operating License (COL) that references a specific reactor design and which would allow us to build and operate a new nuclear unit at North Anna. In January 2008, the NRC accepted our application for the COL and deemed it complete. In December 2008, we terminated a long-lead agreement with our vendor with respect to the reactor design identified in our COL application and certain related equipment. We intend to conduct a competitive process in 2009 to determine if vendors can provide an advanced technology reactor that could be licensed and built under terms acceptable to us. If, as a result of this process, we choose a different reactor design, we will amend our COL application, as necessary. We have not yet committed to building a new nuclear unit.

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

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

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

In March 2008, we also purchased a power station development project in Warren County, Virginia for future development. If developed, the project will involve the construction of a combined cycle, natural gas-fired power station expected to generate about 600 Mw of electricity and will be subject to necessary regulatory approvals.

In addition to the *Powering Virginia* projects, we have invested in several wind farm projects. In December 2006, we acquired a 50% interest in a joint venture with Shell WindEnergy Inc. (Shell) to develop a wind-turbine facility in Grant County, West Virginia (NedPower). NedPower consists of two phases totaling 264 Mw. The first (164 Mw) and second (100 Mw) phases began commercial operations in July and December 2008, respectively.

In January 2008, we acquired a 50% interest in a joint venture with BP Alternative Energy Inc. (BP) to develop a wind-turbine facility in Benton County, Indiana (Fowler Ridge). Fowler Ridge is expected to be built in two phases and generate a total of 650 Mw. The first phase will total 300 Mw and is expected to reach full commercial operations in early 2009. We have a long-term agreement with the joint venture to purchase 200 Mw of energy, capacity and environmental attributes from this first phase. We are currently in discussions with BP regarding development of the final 350 Mw phase. BP has developed an additional 100 Mw facility in which Dominion does not have an ownership interest.

In April 2008, we announced plans to develop a 300 Mw wind-turbine facility in central Illinois (Prairie Fork). Construction of this facility is subject to receipt of all necessary permits and approvals.

In January 2009, we announced a joint effort with BP to evaluate wind energy projects in Tazewell County and Wise County, Virginia, which, if completed, would increase the renewable energy capacity of our utility generation fleet.

Also, in January 2009, we successfully implemented an NRC-approved 7% uprate at Unit 3 of our Millstone power station. This increased the unit's output by approximately 77 Mw from 1,150 Mw to 1,227 Mw, or enough to power an additional 60,000 homes.

Sources of Energy Supply

Dominion Generation uses a variety of fuels to power our electric generation and purchases power for system load requirements, as described below. Some of these agreements have fixed commitments and are included as contractual obligations in *Future Cash Payments for Contractual Obligations and Planned Capital Expenditures* in Item 7. MD&A.

Nuclear Fuel—Dominion Generation primarily utilizes long-term contracts to support its nuclear fuel requirements. Worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices which are dependent on the market environment. Current agreements, inventories and spot market availability are expected to support current and planned fuel supply needs. Additional fuel is purchased as required to ensure optimal cost and inventory levels.

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

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

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

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

Seasonality

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

Nuclear Decommissioning

Dominion Generation has a total of seven licensed, operating nuclear reactors at Surry power station (Surry) and North Anna in Virginia, Millstone power station (Millstone) in Connecticut and Kewaunee power station (Kewaunee) in Wisconsin.

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

We have decommissioning obligations for each of these power stations as discussed in Note 15 to our Consolidated Financial Statements. Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power station once operations have ceased, in accordance with standards established by the NRC. Amounts collected from ratepayers and placed into trusts have been invested to fund the expected future costs of decommissioning the Surry and North Anna units. As part of our acquisition of both Millstone and Kewaunee, we acquired decommissioning funds for the related units.

While the current economic downturn has resulted in a decrease in the value of investments held by our nuclear decommissioning trusts, we believe that the amounts currently available in our decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units. We also believe that the decommissioning funds for the Surry and North Anna units will be sufficient, particularly when combined with ratepayer collections and contributions to these decommissioning trusts, if such future collections and contributions are required. We will continue to monitor our nuclear decommissioning trusts to ensure they meet the minimum financial assurance requirement, which may include the use of parent company guarantees, surety bonding or other financial guarantees recognized by the NRC.

The total estimated cost to decommission our eight nuclear units is $4.5 billion in 2008 dollars and is primarily based upon site-specific studies completed in 2006. For all units except Millstone Units 1 and 2, the current cost estimates assume decommissioning activities will begin shortly after cessation of operations, which will occur when the operating licenses expire. Millstone Unit 1 is not in service and selected minor decommissioning activities are being performed. This unit will continue to be monitored until full decommissioning activities begin for the remaining Millstone units. We expect to start minor decommissioning activities at Millstone Unit 2 in 2035, with full decommissioning of Millstone Units 1, 2 and 3 during the period 2045 to 2059. We expect to decommission the Surry and North Anna units during the period 2032 to 2059. In August 2008, we filed an application with the NRC to renew the Kewaunee operating license. A renewal would permit Kewaunee to operate through December 21, 2033. The NRC docketed the application in October 2008. No requests for a hearing were received on the application, although there will be opportunities for public input as the NRC conducts its review of the application. The NRC's schedule contemplates completion of the uncontested proceeding in November 2010. The license expiration dates for our units are shown in the following table.

(dollars in millions)	NRC license expiration year	Most recent cost estimate (2008 dollars)	Funds in trusts at December 31, 2008	2008 contributions to trusts
Surry				
Unit 1	**2032**	**$ 511**	**$ 296**	**$1.4**
Unit 2	**2033**	**540**	**292**	**1.5**
North Anna				
Unit 1	**2038**	**485**	**239**	**1.0**
Unit 2	**2040**	**507**	**226**	**0.9**
Millstone				
Unit 1	(1)	**619**	**243**	**—**
Unit 2	**2035**	**584**	**291**	**—**
Unit 3	**2045**	**600**	**287**	**—**
Kewaunee				
Unit 1	**2013**(2)	**662**	**372**	**—**
Total		**$4,508**	**$2,246**	**$4.8**

(1) Unit 1 ceased operations in 1998, before our acquisition of Millstone.
(2) Kewaunee Unit 1 original license expiration year is 2013. The license renewal expiration year will be 2033.

Corporate and Other

We also have a Corporate and Other segment that includes our corporate, service company and other functions (including unallocated debt), corporate-wide commodity risk management, the remaining assets of DCI, and the net impact of certain operations disposed of and the results of certain operations to be disposed of, which are discussed in Note 5 to our Consolidated Financial Statements. Operations disposed of during 2008 included certain DCI operations. Operations disposed of during 2007 included all of our non-Appalachian E&P operations, three natural gas-fired merchant generation peaker facilities and certain DCI operations. Operations to be disposed of include Peoples and Hope, which we agreed to sell to BBIFNA in July 2008. In addition, Corporate and Other includes specific items attributable to our operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or allocating resources among the segments.

Environmental Strategy

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

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

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

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

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

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

In addition, Dominion is a 50% owner of the NedPower wind energy facility in Grant County, West Virginia. Our share of this project produces 132 Mw of renewable energy. Dominion has also acquired a 50% interest in a joint venture with BP to develop the Fowler Ridge wind-turbine facility in Benton County, Indiana. The facility is expected to be built in two phases and generate a total of 650 Mw. The first phase will total 300 Mw and is expected to reach full commercial operations in early 2009. We have a long-term agreement with the joint venture to purchase 200 Mw of energy, capacity and environmental attributes from this first phase. We are currently in discussions with BP regarding development of the final 350 Mw phase. BP has developed an additional 100 Mw facility in which Dominion does not have an ownership interest.

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

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

Conservation and Load Management Programs

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

The pilots approved by the Virginia Commission included:

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

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

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

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

REGULATION

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

State Regulations

ELECTRIC

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

Our electric utility subsidiary holds certificates of public convenience and necessity which authorize it to maintain and operate its electric facilities now in operation and to sell electricity to customers. However, this subsidiary may not construct or incur financial commitments for construction of any substantial generating facilities or large capacity transmission lines without the prior approval of various state and federal government agencies. In addition, the Virginia Commission and the North Carolina Commission regulate our electric utility subsidiary's transactions with affiliates, transfers of certain facilities and issuance of securities.

Status of Electric Regulation in Virginia

2007 Virginia Regulation Act and Fuel Factor Amendments

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

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

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

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

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

Virginia Fuel Expenses

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

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

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

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

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

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

North Carolina Regulation

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

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

GAS

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

Status of Competitive Retail Gas Services

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

Ohio—Ohio has not enacted legislation requiring supplier choice for residential or commercial natural gas consumers. However, in cooperation with the Ohio Commission, we have offered retail choice to residential and commercial customers. At December 31, 2008, approximately 849,500 of our 1.2 million Ohio customers were participating in this Energy Choice program. In October 2006, Dominion East Ohio implemented a pilot program approved by the Ohio Commission as a transitional step towards the improvement and expansion of the Energy Choice program. Under the pilot program, Dominion East Ohio entered into gas purchase contracts with selected suppliers at a fixed price above the New York Mercantile Exchange (NYMEX) month-end settlement. This Standard Service Offer (SSO) pricing mechanism replaced the traditional gas cost recovery rate with a monthly market price that eliminates the true-up adjustment, making it easier for customers to compare and switch to competitive suppliers by the end of the transition period.

In June 2008, the Ohio Commission approved a settlement filed in response to Dominion East Ohio's application seeking approval of Phase 2 of its plan to restructure its commodity service. Under that settlement, the existing SSO program was continued through March 2009 with an update to the fixed rate adder to the NYMEX price. Starting in April 2009, Dominion East Ohio will still buy natural gas under the SSO program for customers not eligible to participate in the Energy Choice program, but will place Energy Choice-eligible customers in a direct retail relationship with selected suppliers, which will be designated on the customers' bills. Subject to ultimate Ohio Commission approval, we plan to exit the gas merchant function in Ohio entirely and have all customers select an alternate gas supplier. We will continue to be the provider of last resort in the event of default by a supplier. Large industrial customers in Ohio also source their own natural gas supplies.

Pennsylvania—In Pennsylvania, supplier choice is available for all residential and small commercial customers of Peoples. At December 31, 2008, approximately 108,000 of our 359,000 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 the retail natural gas markets served by Hope. However, the West Virginia Commission has issued regulations to govern pooling services, one of the tools that natural gas suppliers may utilize to provide retail customer choice in the future and has issued rules requiring competitive gas service providers to be licensed in West Virginia.

Rates

Our gas distribution subsidiaries are subject to regulation of rates and other aspects of their businesses by the states in which they operate—Pennsylvania, Ohio and West Virginia. When necessary, our gas distribution subsidiaries seek general base rate increases 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.

In August 2007, Dominion East Ohio filed an application to increase base rates. In this rate case, Dominion East Ohio requested approval of an increase in operating revenues of approximately $73 million and proposed an increase in demand-side management spending. Subsequently, Dominion East Ohio also requested that the Ohio Commission consolidate its review of the rate case application with Dominion East Ohio's application, filed in February 2008, for approval to recover costs related to a 25-year program to replace 19% of its 21,000-mile pipeline system, which is expected to cost approximately $2.6 billion. In August 2008, Dominion East Ohio reached an agreement with intervening parties on all issues in the base rate case except for one related to rate design (Settlement Agreement).

In October 2008, the Ohio Commission issued its Opinion and Order in this case, in which the Ohio Commission approved the majority of the Settlement Agreement, but modified the allowed return on rate base from the 8.49% agreed upon in the Settlement Agreement to 8.29%. The resulting annual revenue increase approved by the Ohio Commission was approximately $37.5 million, which was reflected in base rates commencing October 16, 2008. The Ohio Commission also approved the SFV rate design supported by Ohio Commission staff and Dominion East Ohio for certain rate schedules, as well as the other terms of the Settlement Agreement, including a cost recovery mechanism for the implementation of automated meter reading equipment and a cost recovery mechanism for an initial five-year period of the pipeline replacement program. Under the SFV rate design, Dominion East Ohio will recover a larger portion of its fixed operating costs through a flat monthly charge accompanied by a lower volumetric base delivery rate. In addition, the Settlement Agreement requires Dominion East Ohio to increase its annual spending for energy conservation programs to a total of $9.5 million and to make grants totaling $1.2 million to several organizations to provide payment assistance and energy efficiency education to low-income customers. The Ohio Commission also ordered Dominion East Ohio to work in consultation with Commission staff and other parties to the case to develop a low-income pilot program under which a total of 5,000 eligible low-income, low-usage customers would receive a $4.00 reduction in their monthly service charge, as a result of implementing the new rate design.

In December 2008, the Ohio Commission granted Dominion East Ohio's request for rehearing in the base rate case and approved the 8.49% allowed rate of return on rate base that had been agreed upon previously by all parties to the case. The resulting $3 million annual revenue increase, which was incremental to the $37.5 million increase approved in October 2008, was reflected in revised rates commencing December 22, 2008.

The West Virginia Commission issued an order in March 2008, approving a settlement of Hope's 2005 and 2006 gas cost recovery proceedings, approving the withdrawal of the joint application for approval of the sale of Hope to Equitable, and dismissing the claims of a former employee against Hope. In this order, the West Virginia Commission concluded that no adjustments to Hope's gas cost rates are warranted based on allegations raised by the former employee. Accordingly, the gas cost rates effective November 1, 2007 and April 1, 2008 approved by the March 2008 order have been upheld by the West Virginia Commission.

In October 2008, Hope filed a request with the West Virginia Commission for an increase in the base rates it charges for natural gas service. The requested new base rates would increase Hope's revenues by $34.4 million annually.

Federal Regulations

EPACT and the Repeal of PUHCA

EPACT was signed into law in August 2005. Among other things, EPACT repealed the Public Utilities Holding Company Act (PUHCA) of 1935, effective February 2006. PUHCA regulated many significant aspects of a registered holding company system, such as Dominion's. As a result of PUHCA's repeal, utility holding companies, including Dominion's system, are no longer limited to a single integrated public utility system. Further, utility holding companies are no longer restricted from acquiring businesses that may not be related to the utility business. Jurisdiction over certain holding company related activities has been transferred to the FERC, including the issuances of securities by public utilities, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators are permitted to review the books and records of any company within a holding company system.

EPACT contains key provisions affecting the electric power industry. These provisions include tax changes for the utility industry, incentives for emissions reductions and federal insurance and incentives to build new nuclear power plants. It gives the FERC "backstop" transmission siting authority, as well as increased utility merger oversight. The law also provides incentives and funding for clean coal technologies and initiatives to voluntarily reduce GHG emissions. FERC has issued regulations implementing EPACT. We do not expect compliance with these regulations to have a material adverse impact on our financial condition or results of operations.

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 sells electricity in the PJM wholesale market and our merchant generators sell electricity in the PJM, Midwest ISO and ISO New England wholesale markets under our market-based sales tariffs authorized by FERC. In addition, our electric utility subsidiary has FERC approval of a tariff to sell wholesale power at capped rates based on our embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside our service territory. Any such sales would be voluntary. In May 2005, FERC issued an order finding that PJM's existing transmission service rate design may not be just and reasonable, and ordered an investigation and hearings on the matter. In January 2008, FERC affirmed its earlier decision that the PJM transmission rate design for existing facilities had not become unjust and unreasonable. For recovery of costs of investments of new PJM-planned transmission facilities that operate at or above 500 kV, FERC established a regional rate design where all customers pay a uniform rate based on the costs of such investment. For recovery of costs of investment in new PJM-planned transmission facilities that operate below 500 kV, FERC affirmed its earlier decision to allocate costs on a beneficiary pays approach. A notice of appeal of this decision was filed in February 2008 at the United States Court of Appeals for the Seventh Circuit and the appeal is pending. We cannot predict the outcome of the appeal.

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

We are also subject to FERC's affiliate restrictions that (1) prohibit power sales between our electric utility subsidiary and our merchant plants without first receiving FERC authorization, (2) require the merchant plants and our electric utility subsidiary to conduct their wholesale power sales operations separately, and (3) prohibit our electric utility subsidiary from sharing market information with the merchant plant operating personnel. The rules are designed to prohibit our electric utility subsidiary from giving our merchant plants a competitive advantage.

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

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

In April 2008, FERC granted an application by our electric transmission operations to establish a forward-looking formula rate mechanism that will update transmission rates on an annual basis and approved an ROE of 11.4% on the common equity base of these operations, effective as of January 1, 2008. The formula rate is designed to cover the expected cost of service for each calendar year and will be trued up based on actual costs. While other transmission owners in the PJM region use a formula rate based on historic costs, our formula rate is based on projected costs. The FERC ruling did not materially impact our results of operations; however, going forward the FERC-approved formula method will allow us to earn a more current return on our growing investment in electric transmission infrastructure.

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

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

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

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

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

Gas

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

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

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

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

In December 2007, DTI and the Independent Oil and Gas Association of West Virginia, Inc. reached a settlement agreement on DTI's gathering and processing rates for the period January 1, 2009 through December 31, 2011. This settlement maintains the gas retainage fee structure that DTI has utilized since 2001.

In connection with the settlement, DTI also agreed to invest at least $20 million annually in Appalachian gathering-related assets. The new rates have been approved by FERC as negotiated rates.

Environmental Regulations

General

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

Legal Proceedings and Note 23 to our Consolidated Financial Statements.

Air

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

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

In February 2008, the D.C. Appeals Court issued a ruling that vacates CAMR as promulgated by the EPA. In May 2008, the EPA's appeal of this decision with the D.C. Appeals Court was denied. In September 2008, the Utility Air Regulatory Group filed a petition requesting that the U.S. Supreme Court review the D.C. Appeals Court decision to vacate the EPA rule. In October 2008, the Solicitor General, on behalf of the EPA, also filed a petition with the U.S. Supreme Court, however in February 2009, it filed a motion to dismiss its petition. Also in February 2009 the U.S. Supreme Court denied the Utility Air Regulatory Group's petition. The EPA Administration has announced that the EPA will proceed with a Maximum Achievable Control Technology rule-making. It should be noted that we continue to be governed by individual state mercury emission reduction regulations in Massachusetts and Illinois that were largely unaffected by the CAMR ruling. We cannot predict how the EPA or the states may alter their approach to reducing mercury emissions.

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

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

Implementation of projects to comply with SO_2, NO_X and mercury limitations, and other state emission control programs are ongoing and will be influenced by changes in the regulatory environment, availability of emission allowances and emission control technology. In response to the federal CAA and state regulatory requirements, we estimate that we will make capital expenditures at our affected generating facilities of approximately $700 million during the period 2009 through 2013.

Water

The Clean Water Act (CWA) is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. We must comply with all aspects of the CWA programs at our operating facilities. In July 2004, the EPA published regulations under CWA Section 316b that govern existing utilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold. The EPA's rule presented several compliance options. However, in January 2007, the U.S. Court of Appeals for the Second Circuit issued a decision on an appeal of the regulations, remanding the rule to the EPA. In July 2007, the EPA suspended the regulations pending further rulemaking, consistent with the decision issued by the U.S. Court of Appeals for the Second Circuit. In November 2007, a number of industries appealed the lower court decision to the U.S. Supreme Court. In April 2008, the U.S. Supreme Court granted the industry request to review the question of whether Section 316b of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing "adverse environmental impact" at cooling water intake structures. Oral arguments were presented before the U.S. Supreme Court in December 2008 with a decision expected in 2009. We have sixteen facilities that are likely to be subject to these regulations. We cannot predict the outcome of the judicial or EPA regulatory processes, nor can we determine with any certainty what specific controls may be required.

In August 2006, the Connecticut Department of Environmental Protection (CTDEP) issued a notice of a Tentative Determination to renew our Millstone power station's National Pollutant Discharge Elimination System (NPDES) permit, which included a draft copy of the revised permit. In October 2007, CTDEP issued a report to the hearing officer for the tentative determination stating the agency's intent to further revise the draft permit. In December 2007, the CTDEP issued a new draft permit. An administrative hearing on the draft permit began in January 2009, with a Final Determination expected to be issued by the CTDEP later in 2009. Until the final permit is reissued, it is not possible to predict any financial impact that may result.

In October 2003, the EPA and the Massachusetts Department of Environmental Protection (MADEP) each issued new NPDES permits for Brayton Point. The new permits contained identical conditions that in effect require the installation of cooling towers to address concerns over the withdrawal and discharge of cooling water. Following various appeals, in December 2007, the EPA issued an administrative order to Brayton Point that contained a schedule for implementing the permit. On the same day, Brayton Point withdrew its appeal of the permit from the U.S. Court of Appeals. In March 2008, MADEP issued a companion order resolving the state appeal and implementing the state permit. The state appeal was dismissed the same day. Currently, we estimate the total cost to install these cooling towers at approximately $620 million, which is included in our planned capital expenditures through 2013.

Manufactured Gas Sites

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. For more information on these sites see Note 23 to our Consolidated Financial Statements.

Solid and Hazardous Waste

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

From time to time, we may be identified as a PRP to a Superfund site. Refer to Note 23 to our Consolidated Financial Statements for a description of our exposure relating to our identification as a PRP. We do not believe that any currently identified sites will result in significant liabilities.

Global Climate Change

General

In recent years there has been increased national and international attention to GHG emissions and their relationship to climate change. We expect that there will be federal, regional or state legislative or regulatory action in this area in the near future. Dominion supports national climate change legislation to provide a consistent, economy-wide approach to addressing this issue and is taking action to protect the environment and address climate change while meeting the future needs of its growing service territory. Our CEO and operating segment CEOs are responsible for our compliance with the laws and regulations governing environmental matters, including climate change, and our Board of Directors receives periodic updates on these matters.

For Dominion Generation, our direct CO_2 emissions, based on ownership, were approximately 56 million metric tonnes in 2007. For 2007, DTI's direct CO_2 equivalent emissions were approximately 2.3 million metric tonnes, Dominion East Ohio's direct CO_2 equivalent emissions were approximately 1.4 million metric tonnes and Dominion E&P's direct CO_2 equivalent emissions were approximately 0.4 million metric tonnes. While we do not have final 2008 emissions data for Dominion Generation, DTI, Dominion East Ohio or Dominion E&P, we do not expect a significant variance in emissions from 2007 amounts. With respect to electric generation, the emissions reported are for CO_2 directly emitted to the atmosphere based on the combustion of carbon-based fuels. Direct CO_2 emissions are provided based on emissions from primary stack and emissions from any auxiliary combustion equipment located at the electric generation facility. Primary facility stack emissions of CO_2 from carbon based fuel combustion are directly measured via methods set forth under 40 CFR Part 75 of the United States Code (USC). For those emission sources not covered under 40 CFR Part 75 requirements, quantification is based on fuel combustion and emission factors consistent with industry best practices. For DTI, the protocol used to calculate the non-combustion related emissions reported above was *Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage, Volume 1 – GHG Estimation Methodologies and Procedures. Revision 2, September 28, 2005* developed by the Interstate Natural Gas Association of America. For Dominion East Ohio, the protocol used to calculate the non-combustion related emissions was the *American Gas Association's Draft Greenhouse Emissions Estimation Methodologies and Procedures for Natural Gas Distribution Operations.* For Dominion E&P emissions, the protocol used was the *American Petroleum Institute February 2004 Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry.*

Climate Change Legislation

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

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

Dominion currently supports the enactment of federal legislation that regulates GHG emissions economy-wide, establishes a system of tradable allowances, slows the growth of GHG emissions in the near term and reduces GHG emissions in the long term. In addition, Dominion supports legislation that sets a realistic baseline year and schedule and that is designed in a way to limit potential harm to the economy and competitive businesses.

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

In July 2008, Massachusetts passed the Global Warming Solutions Act (the Act). Among other provisions, the Act sets economy-wide GHG emissions reduction goals for Massachusetts, including reductions of 10% to 25% below 1990 levels by 2020, interim goals for 2030 and 2040, and reductions of 80% below 1990 levels by 2050. Regulations implementing the Act have not yet been proposed or implemented. We operate two coal/oil-fired generating power stations in Massachusetts that are subject to the implementation of the Act.

Additionally, Massachusetts, Rhode Island and Connecticut, among other states, have joined the Regional Greenhouse Gas Initiative (RGGI), a multi-state effort to reduce CO_2 emissions in the Northeast to be implemented through state specific regulations. Under the initiative, aggregate CO_2 emissions from power plants in participating states would be required to be stabilized at current levels from 2009 to 2015. Further, reductions from current levels would be required to be phased in starting in 2016 such that by 2019 there would be a 10% reduction in participating state power plant CO_2 emissions.

Two of our facilities, Brayton Point and Salem Harbor, are subject to existing regulations on CO_2 under Massachusetts Regulation 310 CMR 7.29. These facilities can comply with these regulations either through procurement of GHG emission credits or payment into the Massachusetts GHG Expendable Trust. In 2008, the combined CO_2 compliance obligation for these two power stations is for approximately 456,048 tons of CO_2. The state of Massachusetts has conditionally approved 212,400 tons of GHG emission credits for a Dominion GHG emission credit project.

Three of our facilities, Brayton Point, Salem Harbor and Manchester Street, are subject to RGGI. Beginning with calendar year 2009, RGGI requires that we cover each ton of CO_2 direct stack emissions from these facilities with either an allowance or an offset. The allowances can be purchased through auction or through a secondary market. We participated in allowance auctions in September and December of 2008 and have procured allowances to meet our estimated compliance requirements under RGGI for 2009. We do not expect these allowances to have a material impact on our results of operations or financial condition.

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

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

Dominion's Strategy for Voluntarily Reducing CO_2 Emissions

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

- In 2003, we retired two oil-fired units at our Possum Point power station, replacing them with a new 559 Mw combined cycle natural gas technology. We also converted two coal-fired units to cleaner burning natural gas.
- Since 2000, Dominion has added approximately 2,900 Mw of new lower-emitting natural gas-fired generation (excluding Possum Point) and more than 2,500 Mw of non-emitting nuclear generation to its generation mix.
- We have also added 83 Mw of renewable biomass.
- We have approximately 750 Mw of wind energy in operation or development. Also, in April 2008, we announced an agreement with BP to jointly develop, own and operate wind energy projects in Virginia. In connection with this agreement, in January 2009, we announced a joint effort with BP to evaluate wind energy projects in Tazewell County and Wise County, Virginia.
- In December 2007, we announced that we had acquired a 590-Mw combined-cycle natural gas-fired development project in Buckingham County, Virginia (Bear Garden).
- We have received an early site permit from the NRC for the possible addition of approximately 1,500 Mw of nuclear generation in Virginia.

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

Since 2000, we have tracked the emissions of our electric generation fleet. Our electric generation fleet employs a mix of fuel and renewable energy sources. Comparing annual year 2000 to annual year 2007, our electric generating fleet (based on our ownership percentage) reduced its average CO_2 emissions rate per megawatt-hour of energy produced from electric generation by about 15%. During such time period the capacity of our electric generation fleet has grown.

Nuclear Regulatory Commission

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

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

The NRC also requires us to decontaminate our nuclear facilities once operations cease. This process is referred to as decommissioning, and we are required by the NRC to be financially prepared. For information on our decommissioning trusts, see *Dominion Generation—Nuclear Decommissioning* and Note 11 to our Consolidated Financial Statements.

Spent Nuclear Fuel

Under provisions of the Nuclear Waste Policy Act of 1982, we have entered into contracts with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by our contracts with the DOE. In January 2004, we and certain of our direct and indirect subsidiaries filed lawsuits in the U.S. Court of Federal Claims against the DOE requesting damages in connection with its failure to commence accepting spent nuclear fuel. A trial occurred in May 2008 and post-trial briefing and argument concluded in July 2008. On October 15, 2008, the Court issued an opinion and order for us in the amount of approximately $155 million for our spent fuel-related costs through June 30, 2006, and judgment was entered by the Court on October 28, 2008. On December 24, 2008, the government appealed the judgment to the U. S. Court of Appeals for the Federal Circuit and the appeal was docketed on December 30, 2008. Briefing on the appeal is expected to take place in 2009. Payment of any damages will not occur until the appeal process has been resolved. We cannot predict the outcome of this matter; however, in the event that we recover damages, such recovery, including amounts attributable to joint owners, is not expected to have a material impact on our results of operations. We will continue to manage our spent fuel until it is accepted by the DOE.

Item 1A. Risk Factors

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

Our results of operations can be affected by changes in the weather. Weather conditions directly influence the demand for electricity and natural gas, and affect the price of energy commodities. In addition, severe weather, including hurricanes and winter storms, can be destructive, causing outages and property damage that require us to incur additional expenses. Additionally, droughts can result in reduced water levels that could adversely affect operations at some of our power stations.

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

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

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

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

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

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

The rates of our electric and gas transmission operations are subject to regulatory review. Revenue provided by our electric and gas transmission operations is based primarily on rates approved by FERC. The profitability of these businesses is dependent on their ability, through the rates that they are permitted to charge, to recover costs and earn a reasonable rate of return on their capital investment.

Our wholesale charges for electric transmission service are adjusted on an annual basis through operation of a FERC-approved formula rate mechanism. Through this mechanism our wholesale electric transmission cost of service is estimated and thereafter trued-up as appropriate to reflect actual costs allocated to the Company by PJM. These wholesale rates are subject to FERC review and prospective adjustment in the event that customers and/or interested state commissions file a complaint with FERC and are able to demonstrate that our wholesale revenue requirement is no longer just and reasonable.

Similarly, various rates and charges assessed by our gas transmission businesses are subject to review by FERC. We are required to file a general base rate review for the FERC-jurisdictional services of Cove Point, effective not later than July 31, 2011. At that time, Cove Point's cost of service will be reviewed by the FERC, with rates set based on analyses of the company's costs and capital structure. The FERC-jurisdictional rates for DTI are the subject of a 2005 FERC-approved settlement. That settlement established a rate moratorium that continues in effect through June 30, 2010.

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

Our 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 including our ability to purchase and sell power at prices sufficient to cover our operating costs. We operate in active wholesale markets that expose us to price volatility for electricity and fuel as well as the credit risk of counterparties. We attempt to manage our price risk by entering into hedging transactions, including short-term and long-term fixed price sales and purchase contracts.

In these wholesale markets, the spot market price of electricity for each hour is generally determined by the cost of supplying the next unit of electricity to the market during that hour. In many cases, the next unit of electricity supplied would be provided by generating stations that consume fossil fuels, primarily natural gas. Consequently the open market wholesale price for electricity generally reflects the cost of natural gas plus the cost to convert the fuel to electricity. Therefore changes in the price of natural gas generally affect the open market wholesale price of electricity. To the extent we do not enter into long-term power purchase agreements or otherwise hedge our output, then these changes in market prices could adversely affect our financial results.

In addition, we purchase fuel under a variety of terms, including long-term and short-term contracts and spot market purchases. We are exposed to fuel cost volatility for the portion of our fuel obtained through short-term contracts or on the spot market. Fuel prices can be volatile and the price that can be obtained for power produced from such fuel may not change at the same rate as fuel costs, thus adversely impacting our financial results.

Lastly, we are exposed to credit risks of our counterparties and the risk that one or more counterparties may fail to perform under their obligations to make payments. Defaults by suppliers or other counterparties may adversely affect our financial results.

Our merchant power business may be negatively affected by possible FERC actions that could weaken competition in the wholesale markets or affect pricing rules in the RTO markets. Our merchant generation stations operating in PJM and NEPOOL sell capacity, energy and ancillary services into wholesale electricity markets regulated by FERC. The wholesale markets allow these merchant generation stations to take advantage of market price opportunities, but also exposes them to market risk. Properly functioning competitive wholesale markets in PJM and NEPOOL depend upon FERC's continuation of clearly identified market rules. From time to time FERC may investigate and authorize PJM and NEPOOL to make changes in market design. FERC also periodically reviews our authority to sell at market-based rates. Material changes by FERC to the design of the wholesale markets or our authority to sell power at market-based rates could adversely impact the future results of our merchant power business.

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

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

There are risks associated with the operation of nuclear facilities. We operate nuclear facilities that are subject to risks, including our ability to dispose of spent nuclear fuel, the disposal of which is subject to complex federal and state regulatory constraints. These risks also include the cost of and our ability to maintain adequate reserves for decommissioning, costs of replacement power, costs of plant maintenance and exposure to potential liabilities arising out of the operation of these facilities. We maintain decommissioning trusts and external insurance coverage to mitigate the financial exposure to these risks. However, it is possible that decommissioning costs could exceed the amount in our trusts or that costs arising from claims could exceed the amount of any insurance coverage.

The use of derivative instruments could result in financial losses and liquidity constraints. We use derivative instruments, including futures, swaps, forwards, options and financial transmission rights (FTRs) to manage our commodity and financial market risks. In addition, we purchase and sell commodity-based contracts primarily in the natural gas market for trading purposes. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively-quoted market prices and pricing information from external sources, the valuation of these contracts involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

In addition, we use derivatives to hedge our electric and gas operations. The use of such derivatives to hedge future electric and gas sales may limit the benefit we would otherwise receive from increases in commodity prices. These hedge arrangements generally include collateral requirements that require us to deposit funds or post letters of credit with counterparties to cover the fair value of covered contracts in excess of agreed upon credit limits. For instance, 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 or obtain additional liquidity to cover these collateral requirements. In some circumstances, this could have a compounding effect on our financial liquidity and results of operations.

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

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

For additional information concerning derivatives and commodity-based trading contracts, see *Market Risk Sensitive Instruments and Risk Management* in Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Notes 2 and 9 to our Consolidated Financial Statements.

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

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

We may not complete plant construction or expansion projects that we commence, or we may complete projects on materially different terms or timing than initially anticipated and we may not be able to achieve the intended benefits of any such project, if completed. We have announced several plant construction and expansion projects and may consider additional projects in the future. We anticipate that we will be required to seek additional financing in the future to fund our current and future plant construction and expansion projects and we may not be able to secure such financing on favorable terms. In addition, we may not be able to complete the projects on time as a result of weather conditions, delays in obtaining or failure to obtain regulatory approvals, delays in obtaining key materials, labor difficulties, difficulties with partners or potential partners, a decline in the credit strength of our counterparties or vendors, or other factors beyond our control. With respect to our LNG and gas transmission pipeline operations, if we do not meet designated schedules for approval and construction of our plant and expansion projects, certain of our customers may have the right to terminate their precedent agreements relating to the expansion projects. Certain of our customers may also have the right to receive liquidated damages. Even if plant construction and expansion projects are completed, the total costs of the projects may be higher than anticipated and the performance of our business following the projects may not meet expectations. Additionally, regulators may disallow recovery of some of the costs of a project if they are deemed not to be prudently incurred. Further, we may not be able to timely and effectively integrate the projects into our operations and such integration may result in unforeseen operating difficulties or unanticipated costs. Any of these or other factors could adversely affect our ability to realize the anticipated benefits from the plant construction and expansion projects.

An inability to access financial markets could affect the execution of our business plan. Dominion and our subsidiary, Virginia Power, rely on access to short-term money markets, longer-term capital markets and banks as significant sources of funding and liquidity for capital expenditures, normal working capital and collateral requirements related to hedges of future sales and purchases of energy-related commodities primarily associated with our merchant generation and gas and oil production. Management believes that Dominion and Virginia Power will maintain sufficient access to these financial markets based upon our current credit ratings and market reputation. However, certain disruptions outside of our control may increase our cost of borrowing or restrict our ability to access one or more financial markets. Such disruptions could include a continuation of the current economic downturn, the bankruptcy of an unrelated company, general market disruption due to general credit market or political events, changes to our credit ratings or the failure of financial institutions on which we rely. Restrictions on our ability to access financial markets may affect our ability to execute our business plan as scheduled.

Market performance and other changes may decrease the value of decommissioning trust funds and benefit plan assets or increase our liabilities, which then could require significant additional funding. The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations to decommission our nuclear plants and under our pension and postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuation and will yield uncertain returns, which may fall below our expected return rates. A decline in the market value of the assets may increase the funding requirements of the obligations to decommission our nuclear plants and under our pension and postretirement benefit plans. Additionally, changes in interest rates affect the liabilities under our pension and postretirement benefit plans; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions, may also increase the funding requirements of the obligations related to the pension benefit plans. If the decommissioning trust funds and benefit plan assets are not successfully managed, our results of operations and financial condition could be negatively affected.

Changing rating agency requirements could negatively affect our growth and business strategy. As of February 1, 2009, Dominion's senior unsecured debt is rated A-, stable outlook, by Standard & Poor's; Baa2, stable outlook, by Moody's; and BBB+, stable outlook, by 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 subsidiary by Standard & Poor's, Moody's or Fitch could increase our borrowing costs and adversely affect operating results and could require us to post additional collateral in connection with some of our price risk management activities.

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

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2008, we owned our principal executive office and three other corporate offices, all located in Richmond, Virginia. We also lease corporate offices in other cities in which our subsidiaries operate.

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

Substantially all of our electric utility's property is subject to the lien of the Indenture of Mortgage securing its First and Refunding Mortgage Bonds. There were no bonds outstanding as of December 31, 2008, however, by leaving the indenture open we retain the flexibility to issue mortgage bonds in the future. Certain of our merchant generation facilities are also subject to liens.

The following information detailing our gas and oil operations reflects our Appalachian E&P operations, which are included in the Dominion Energy segment, as well as our non-Appalachian E&P operations divested during 2007, which are included in the Corporate and Other segment.

COMPANY-OWNED PROVED GAS AND OIL RESERVES

Estimated net quantities of proved gas and oil reserves were as follows:

At December 31,	**2008**		2007		2006	
	Proved Developed	**Total Proved**	Proved Developed	Total Proved	Proved Developed	Total Proved
Proved gas reserves (bcf)						
U.S.	**672**	**1,099**	636	1,019	3,424	4,961
Canada	**—**	**—**	—	—	132	175
Total proved gas reserves	**672**	**1,099**	636	1,019	3,556	5,136
Proved oil reserves (000 bbl)						
U.S.	**12,406**	**12,434**	12,613	12,613	173,718	216,849
Canada	**—**	**—**	—	—	7,061	15,410
Total proved oil reserves	**12,406**	**12,434**	12,613	12,613	180,779	232,259
Total proved gas and oil reserves (bcfe)[1]	**746**	**1,173**	712	1,095	4,640	6,530

bbl = barrel

(1) Ending reserves for 2008, 2007 and 2006 included 1.0 million, 0.3 million and 114.6 million barrels of oil/condensate, respectively, and 11.4 million, 12.3 and 117.7 million barrels of natural gas liquids, respectively.

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 previous table 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 previous table, does not exceed five percent. Estimated proved reserves as of December 31, 2008 are based upon studies for each of our properties prepared by our staff engineers and audited by Ryder Scott Company, L.P. Calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC guidelines.

QUANTITIES OF GAS AND OIL PRODUCED

Quantities of gas and oil produced follow:

Year Ended December 31,	**2008**	2007	2006
Gas production (bcf)			
U.S.	**59**	206	302
Canada	**—**	8	16
Total gas production	**59**	214	318
Oil production (000 bbl)			
U.S.	**919**	11,626	23,923
Canada	**—**	559	1,024
Total oil production	**919**	12,185	24,947
Total gas and oil production (bcfe)	**65**	287	467

The average realized price per mcf of gas with hedging results (including transfers to other Dominion operations at market prices) during the years 2008, 2007 and 2006 was $8.71, $5.99 and $4.41, respectively. The respective average realized prices without hedging results per mcf of gas produced were $8.96, $6.63 and $6.67. The respective average realized prices for oil with hedging results were $38.03, $37.78 and $33.42 per barrel and the respective average realized prices without hedging results were $38.51, $50.08 and $54.49 per barrel. The average production (lifting) cost per mcf equivalent of gas and oil produced (as calculated per SEC guidelines) during the years 2008, 2007 and 2006 was $1.37, $1.39 and $1.18, respectively.

ACREAGE

Gross and net developed acreage (in thousands) at December 31, 2008 were 1,430 and 1,338 acres, respectively. Gross and net undeveloped acreage (in thousands) at December 31, 2008 were 341 and 205 acres, respectively.

NET WELLS DRILLED IN THE CALENDAR YEAR

The number of net wells completed follows:

Year Ended December 31,	**2008**	2007	2006
Exploratory:			
U.S.			
Productive	—	—	6
Dry	—	—	3
Total U.S.	—	—	9
Canada			
Productive	—	—	33
Dry	—	—	4
Total Canada	—	—	37
Total Exploratory	—	—	46
Development:			
U.S.			
Productive	**384**	804	1,039
Dry	**2**	10	33
Total U.S.	**386**	814	1,072
Canada			
Productive	—	10	31
Dry	—	—	4
Total Canada	—	10	35
Total Development	**386**	824	1,107
Total wells drilled (net):	**386**	824	1,153

As of December 31, 2008, 63 gross (59 net) wells were in the process of being drilled, including wells temporarily suspended.

PRODUCTIVE WELLS

At December 31, 2008, our subsidiaries had an interest in 9,493 and 8,699 productive gas wells, gross and net, respectively. Our subsidiaries did not have an interest in any productive oil wells at December 31, 2008.

Power Generation

We generate electricity for sale on a wholesale and a retail level. We supply electricity demand either from our generation facilities or through purchased power contracts. As of December 31, 2008, Dominion Generation's total utility and merchant generating capacity was 27,090 Mw.

The following table lists Dominion Generation's utility generating units and capability, as of December 31, 2008:

Plant	Location	Net Summer Capability (Mw)	Percentage Net Summer Capability
Coal			
Mt. Storm	Mt. Storm, WV	1,560	
Chesterfield	Chester, VA	1,235	
Chesapeake	Chesapeake, VA	595	
Clover	Clover, VA	433[a]	
Yorktown	Yorktown, VA	323	
Bremo	Bremo Bluff, VA	227	
Mecklenburg	Clarksville, VA	138	
North Branch	Bayard, WV	74	
Altavista	Altavista, VA	63	
Polyester[b]	Hopewell, VA	63	
Southampton	Southampton, VA	63	
Total Coal		4,774	26%
Gas			
Ladysmith (CT)	Ladysmith, VA	623	
Remington (CT)	Remington, VA	608	
Possum Point (CC)	Dumfries, VA	559	
Chesterfield (CC)	Chester, VA	397	
Elizabeth River (CT)	Chesapeake, VA	348	
Possum Point	Dumfries, VA	316	
Bellemeade (CC)	Richmond, VA	245	
Gordonsville Energy (CC)	Gordonsville, VA	218	
Darbytown (CT)	Richmond, VA	168	
Rosemary (CC)	Roanoke Rapids, NC	165	
Gravel Neck (CT)	Surry, VA	158	
Total Gas		3,805	21
Nuclear			
Surry	Surry, VA	1,598	
North Anna	Mineral, VA	1,596[c]	
Total Nuclear		3,194	18
Oil			
Yorktown	Yorktown, VA	818	
Possum Point	Dumfries, VA	786	
Gravel Neck (CT)	Surry, VA	186	
Darbytown (CT)	Richmond, VA	168	
Chesapeake (CT)	Chesapeake, VA	115	
Possum Point (CT)	Dumfries, VA	72	
Low Moor (CT)	Covington, VA	48	
Northern Neck (CT)	Lively, VA	47	
Kitty Hawk (CT)	Kitty Hawk, NC	31	
Total Oil		2,271	13
Hydro			
Bath County	Warm Springs, VA	1,754[d]	
Gaston	Roanoke Rapids, NC	220	
Roanoke Rapids	Roanoke Rapids, NC	95	
Other	Various	3	
Total Hydro		2,072	11
Biomass			
Pittsylvania	Hurt, VA	83	1
Various			
Other	Various	11	—
		16,210	
Power Purchase Agreements		1,860	10
Total Utility Generation		18,070	100%

Note: (CT) denotes combustion turbine and (CC) denotes combined cycle.
(a) Excludes 50% undivided interest owned by ODEC.
(b) Previously referred to as Hopewell.
(c) Excludes 11.6% undivided interest owned by ODEC.
(d) Excludes 40% undivided interest owned by Allegheny Generating Company, a subsidiary of Allegheny Energy, Inc.

The following table lists Dominion Generation's merchant generating units and capability, as of December 31, 2008:

Plant	Location	Net Summer Capability (Mw)	Percentage Net Summer Capability
Coal			
Kincaid	Kincaid, IL	1,158[(a)]	
Brayton Point	Somerset, MA	1,122	
State Line	Hammond, IN	515	
Salem Harbor	Salem, MA	314	
Morgantown	Morgantown, WV	25[(a),(b)]	
Total Coal		3,134	35%
Nuclear			
Millstone	Waterford, CT	2,023[(c)]	
Kewaunee	Kewaunee, WI	556	
Total Nuclear		2,579	29
Gas			
Fairless (CC)	Fairless Hills, PA	1,136[(d)]	
Elwood (CT)	Elwood, IL	712[(a),(e)]	
Manchester (CC)	Providence, RI	432	
Total Gas		2,280	25
Oil			
Salem Harbor	Salem, MA	440	
Brayton Point	Somerset, MA	438	
Total Oil		878	10
Wind			
NedPower Mt. Storm	Grant County, WV	132[(a),(f)]	1
Various			
Other	Various	17	—
Total Merchant Generation		9,020	100%

Note: (CT) denotes combustion turbine and (CC) denotes combined cycle.
(a) Subject to a lien securing the facility's debt.
(b) Excludes 50% partnership interest owned by RCM Morgantown Power, Ltd. and Hickory Power LLC.
(c) Excludes 6.53% undivided interest in Unit 3 owned by Massachusetts Municipal Wholesale Electric Company and Central Vermont Public Service Corporation.
(d) Includes generating units that we operate under leasing arrangements.
(e) Excludes 50% membership interest owned by J. POWER Elwood, LLC.
(f) Excludes 50% membership interest owned by Shell.

Item 3. Legal Proceedings

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

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

In October 2003, the EPA and MADEP each issued new NPDES permits for Brayton Point. The new permits contained identical conditions that in effect require the installation of cooling towers to address concerns over the withdrawal and discharge of cooling water. Following various appeals by Brayton Point, in December 2007, the EPA issued an administrative order to Brayton Point that contained a schedule for implementing the permit. On the same day, Brayton Point withdrew its appeal of the permit from the U.S. Court of Appeals, and in March 2008, the related state appeal of the permit was also dismissed.

In December 2006 and January 2007, we submitted self-disclosure notifications to EPA Region 8 regarding three E&P facilities in Utah that potentially violated CAA permitting requirements. In July 2007, a third party purchased Dominion's E&P assets in Utah, including these facilities. In September 2008, we received a draft Consent Decree related to the potential CAA infractions, which imposes obligations on our subsidiary, DEPI and the purchaser, including payment of a civil penalty to the DOJ in the amount of $250,000. We expect the Consent Decree will be executed during the first quarter of 2009, after which it will be posted for public notice and comment for a period of not less than thirty days. Following the execution of the Consent Decree and the expiration of the 30-day public notice and comment period, the DOJ may request the federal judge in this proceeding to enter a final Consent Decree. Per our asset purchase agreement, the third-party purchaser assumed responsibility for the resolution of any enforcement action or Consent Decree, including penalties.

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

None.

Executive Officers of the Registrant

Name and Age	Business Experience Past Five Years[1]
Thomas F. Farrell, II (54)	Chairman of the Board of Directors of Dominion Resources, Inc. (DRI) from April 2007 to date; President and CEO of DRI from January 2006 to date; Chairman of the Board of Directors and CEO of Virginia Electric and Power Company (VP) from February 2006 to date; Chairman of the Board of Directors, President and CEO of Consolidated Natural Gas Company (CNG) from January 2006 to June 2007; Director of DRI from March 2005 to April 2007; President and Chief Operating Officer (COO) of DRI and CNG from January 2004 to December 2005.
Thomas N. Chewning (63)	Executive Vice President and CFO of DRI from May 1999 to date; Executive Vice President and CFO of CNG from January 2000 to June 2007; Executive Vice President and CFO of VP from February 2006 to date.
Paul D. Koonce (49)	Executive Vice President of DRI from April 2006 to date; President and COO—Energy of VP from February 2006 to September 2007; CEO—Energy of VP from January 2004 to January 2006.
Mark F. McGettrick (51)	Executive Vice President of DRI from April 2006 to date; President and COO—Generation of VP from February 2006 to date; President and CEO—Generation of VP from January 2003 to January 2006.
David A. Christian (54)	President and Chief Nuclear Officer (CNO) of VP from October 2007 to date; Senior Vice President—Nuclear Operations and CNO of VP from April 2000 to September 2007.
David A. Heacock (51)	Senior Vice President of DRI and President and COO—Dominion Virginia Power of VP from June 2008 to date; Senior Vice President—Dominion Virginia Power of VP from October 2007 to May 2008; Senior Vice President—Fossil & Hydro of VP from April 2005 to September 2007; Vice President—Fossil & Hydro System Operations of VP from December 2003 to April 2005.
Robert M. Blue (41)	Senior Vice President—Public Policy and Corporate Communications of DRI and Dominion Resources Services, Inc. (DRS) from May 2008 to date; Vice President—State and Federal Affairs of DRS from September 2006 to May 2008; Managing Director State Affairs and Corporate Policy of DRS from July 2005 to August 2006; Counselor to former Virginia Governor Mark R. Warner and Director of Policy from January 2002 to May 2005.
Mary C. Doswell (50)	Senior Vice President—Regulation and Integrated Planning of DRI, VP and DRS from October 2007 to date; Senior Vice President and Chief Administrative Officer (CAO) of DRI from January 2003 to September 2007; President and CEO of DRS from January 2004 to September 2007.
Steven A. Rogers (47)	President and CAO of DRS, Senior Vice President and CAO of DRI from October 2007 to date; Senior Vice President and Chief Accounting Officer of DRI and VP from January 2007 to September 2007 and CNG from January 2007 to June 2007; Senior Vice President and Controller of DRI and CNG from April 2006 to December 2006; Senior Vice President (Principal Accounting Officer) (PAO) of VP from April 2006 to December 2006; Vice President and Controller of DRI and CNG and Vice President and PAO of VP from June 2000 to April 2006.
James F. Stutts (64)	Senior Vice President and General Counsel of DRI and VP from January 2007 to date and CNG from January 2007 to June 2007; Vice President and General Counsel of DRI from September 1997 to December 2006; Vice President and General Counsel of VP from January 2002 to December 2006; Vice President and General Counsel of CNG from January 2000 to December 2006.
Thomas P. Wohlfarth (48)	Senior Vice President and Chief Accounting Officer of DRI, VP and DRS from October 2007 to date; Vice President—Budgeting, Forecasting & Investor Relations of DRS from February 2006 to September 2007; Vice President—Financial Management of VP from January 2004 to January 2006.
Carter M. Reid (40)	Vice President—Governance and Corporate Secretary of DRI and VP from December 2007 to date; Vice President—Governance of DRI from October 2007 to November 2007; Director Executive Compensation and Legal Advisor of DRS from February 2006 to September, 2007; Director Executive Compensation of DRS from July 2003 to January 2006.

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

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, 2008, there were approximately 151,000 registered shareholders, including approximately 58,000 certificate holders. Restrictions on our payment of dividends are discussed in *Dividend Restrictions* in Item 7. MD&A and Note 21 to our Consolidated Financial Statements. Quarterly information concerning stock prices and dividends is disclosed in Note 28 to our Consolidated Financial Statements.

The following table presents certain information with respect to our common stock repurchases during the fourth quarter of 2008.

Issuer Purchases of Equity Securities

Period	(a) Total Number of Shares (or Units) Purchased[1]	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased under the Plans or Program
10/1/08 - 10/31/08	**—**	**$ —**	**N/A**	**53,971,148 shares/$2.68 billion**
11/1/08 - 11/30/08	**935**	**$36.78**	**N/A**	**53,971,148 shares/$2.68 billion**
12/1/08 - 12/31/08	**16,579**	**$34.87**	**N/A**	**53,971,148 shares/$2.68 billion**
Total	**17,514**	**$34.98[2]**	**N/A**	**53,971,148 shares/$2.68 billion**

(1) Amount reflects registered shares tendered by employees to satisfy tax withholding obligations on vested restricted stock.
(2) Represents the weighted-average price paid per share during the fourth quarter of 2008.

Item 6. Selected Financial Data

Year Ended December 31,	**2008[1]**	2007[2]	2006[3]	2005[4]	2004[5]
(millions, except per share amounts)					
Operating revenue[6]	**$16,290**	$14,816	$17,276	$16,766	$13,711
Income from continuing operations before extraordinary item and cumulative effect of changes in accounting principles	**1,836**	2,705	1,530	1,033	1,255
Income (loss) from discontinued operations, net of tax[7]	**(2)**	(8)	(150)	6	(6)
Extraordinary item, net of tax	—	(158)	—	—	—
Cumulative effect of changes in accounting principles, net of tax	—	—	—	(6)	—
Net income	**1,834**	2,539	1,380	1,033	1,249
Income from continuing operations before extraordinary item and cumulative effect of changes in accounting principles per common share—basic	**3.17**	4.15	2.19	1.51	1.91
Net income per common share—basic	**3.17**	3.90	1.97	1.51	1.90
Income from continuing operations before extraordinary item and cumulative effect of changes in accounting principles per common share—diluted	**3.16**	4.13	2.17	1.50	1.90
Net income per common share—diluted	**3.16**	3.88	1.96	1.50	1.89
Dividends paid per share	**1.58**	1.46	1.38	1.34	1.30
Total assets[8]	**42,053**	39,139	49,296	52,683	45,466
Long-term debt	**14,956**	13,235	14,791	14,653	15,507

(1) Includes a $136 million after-tax net income benefit due to the reversal of deferred tax liabilities associated with the planned sale of Peoples and Hope.

(2) Includes a $1.5 billion after-tax net income benefit from the disposition of our non-Appalachian E&P operations as discussed in Note 5 to our Consolidated Financial Statements. Also includes a $252 million after-tax impairment charge associated with the sale of Dresden and a $158 million after-tax extraordinary charge resulting from the reapplication of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, to the Virginia jurisdiction of our utility generation operations as discussed in Note 2 to our Consolidated Financial Statements. Also includes a $137 million after-tax charge resulting from the termination of the long-term power sales agreement associated with State Line.

(3) Includes a $164 million after-tax impairment charge related to the Peaker facilities that were sold in March 2007 and a $104 million after-tax charge resulting from the write-off of certain regulatory assets related to the planned sale of Peoples and Hope. See Note 5 to our Consolidated Financial Statements.

(4) Includes a $272 million after-tax loss related to the discontinuance of hedge accounting for certain gas and oil derivatives, 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.

(5) 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 derivatives, 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 derivatives during the third quarter.

(6) In the fourth quarter of 2008, we revised our derivative income statement classification policy to present income statement activity for all non-trading derivatives based on the nature of the underlying risk as discussed in Note 2 to our Consolidated Financial Statements. Prior periods have been recast to conform to this presentation.

(7) Reflects the net impact of the discontinued operations of certain DCI operations sold in August 2007, Canadian E&P operations sold in June 2007, Peaker facilities sold in March 2007 and telecommunications operations sold in May 2004. See Note 5 to our Consolidated Financial Statements.

(8) Reflects the impact of adopting FSP FIN 39-1, Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts, as discussed in Note 3 to our Consolidated Financial Statements.

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

MD&A discusses our results of operations and general financial condition. MD&A should be read in conjunction with Item 1. Business and our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data. 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 or more of Dominion Resources, Inc.'s consolidated subsidiaries or operating segments or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries.

CONTENTS OF MD&A

Our MD&A consists of the following information:

FORWARD-LOOKING STATEMENTS

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

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

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events, including hurricanes and winter storms, that can cause outages and property damage to our facilities;
- State and federal legislative and regulatory developments and changes to environmental and other laws and regulations, including those related to climate change, GHG emissions and other emissions to which we are subject;
- Cost of environmental compliance, including those costs related to climate change;
- Risks associated with the operation of nuclear facilities;
- Fluctuations in energy-related commodity prices and the effect these could have on our earnings, liquidity position and the underlying value of our assets;
- 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 federal and state tax laws and regulations;
- Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;
- Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
- The risks of operating businesses in regulated industries that are subject to changing regulatory structures;
- Receipt of approvals for and timing of closing dates for acquisitions and divestitures;
- Changes in rules for RTOs in which we participate, including changes in rate designs and new and evolving capacity models;
- Political and economic conditions, including the threat of domestic terrorism, inflation and deflation;
- Changes to rates for our regulated electric utility operations, including the outcome of our 2009 base rate review, and the timing of such collection as it relates to fuel costs;
- Timing and receipt of regulatory approvals necessary for planned construction or expansion projects;
- The inability to complete planned construction projects within the terms and time frames initially anticipated;
- Completing the divestiture of Peoples and Hope; and
- Adverse outcomes in litigation matters.

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

Our forward-looking statements are based on our beliefs and assumptions using information available at the time the statements are made. We caution the reader not to place undue reliance on our forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results. We undertake no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

ACCOUNTING MATTERS

Critical Accounting Policies and Estimates

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

ACCOUNTING FOR DERIVATIVE CONTRACTS AND OTHER INSTRUMENTS AT FAIR VALUE

We use derivative contracts such as futures, swaps, forwards, options and FTRs to manage the commodity and financial markets risks of our business operations. Derivative contracts, with certain exceptions, are subject to fair value accounting, as prescribed by SFAS No. 157, *Fair Value Measurements*, and are reported in our Consolidated Balance Sheets at fair value. Accounting requirements for derivatives and related hedging activities are complex and may be subject to further clarification by standard-setting bodies. The majority of investments held in our nuclear decommissioning and rabbi trust funds are also subject to fair value accounting. Assets held in our pension and other postretirement benefit plans are subject to the fair value measurement requirements of SFAS No. 157, but are currently not subject to fair value disclosure requirements. Therefore they are not included in the level summaries presented below. See Note 8 of our Consolidated Financial Statements for further information on our fair value measurements.

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

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

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

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

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

Level 3—Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 consist of long-dated commodity derivatives, natural gas liquids contracts (NGLs), natural gas peaking options, FTRs and other modeled commodity derivatives.

Fair value measurements are categorized as Level 3 when a significant amount of price or other inputs that are considered to be unobservable are used in their valuations. Long-dated commodity derivatives are based on unobservable inputs due to the length of time to settlement and absence of market activity and are therefore categorized as Level 3. For NGLs, market illiquidity requires a valuation based on proxy markets that do not always correlate to the actual instrument, therefore they are also categorized as Level 3. For the same illiquidity reason, natural gas peaking options at non-Henry Hub locations are valued using Henry Hub (NYMEX natural gas delivery point) volatilities, which may or may not be identical to the volatilities at transacted locations, and are therefore not considered to be observable inputs. FTRs are categorized as Level 3 fair value measurements because the only relevant pricing available comes from ISO auctions, which is accurate for day-one valuation, but generally is not considered to be representative of the ultimate settlement values. Other modeled commodity derivatives have unobservable inputs in their valuation, mostly due to non-transparent and illiquid markets.

As of December 31, 2008, our net balance of commodity derivatives categorized as Level 3 fair value measurements was a net asset of $99 million. A hypothetical 10% increase in commodity prices would decrease the net asset by $21 million, while a hypothetical 10% decrease in commodity prices would increase the net asset by $20 million.

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

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

Use of Estimates in Goodwill Impairment Testing

As of December 31, 2008, we reported $3.5 billion of goodwill in our Consolidated Balance Sheet. A significant portion resulted from the acquisition of the former CNG in 2000.

In April of each year, we test our goodwill for potential impairment, and perform additional tests more frequently if 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. The 2008, 2007 and 2006 annual tests did not result in the recognition of any goodwill impairment.

As a result of the 2007 disposition of our non-Appalachian E&P operations, goodwill was allocated to such operations based on the relative fair values of the E&P operations being disposed of and the Appalachian portion being retained. The impairment test performed on the goodwill allocated to the retained Appalachian operations showed no impairment. Also, in connection with the 2007 segment realignment, the goodwill allocated to our three gas distribution subsidiaries was tested for impairment during the fourth quarter of 2007. This interim test did not result in the recognition of any goodwill impairment, as the estimated fair values of these businesses exceeded their respective carrying amounts. There were no significant changes to goodwill during the year ended December 31, 2008.

In general, we estimate the fair value of our reporting units by using a combination of discounted cash flows, and other valuation techniques that use multiples of earnings for peer group companies and analyses of recent business combinations involving peer group companies. For our non-Appalachian E&P operations, our regulated gas distribution subsidiaries held for sale and certain DCI operations, negotiated sales prices were used as fair value for the tests conducted in 2008 and 2007. Fair value estimates are dependent on subjective factors such as our estimate of future cash flows, the selection of appropriate discount and growth rates, and the selection of peer group companies and recent transactions. These underlying assumptions and estimates are made as of a point in time; subsequent modifications, particularly changes in discount rates or growth rates inherent in our estimates of future cash flows, could result in a future impairment of goodwill. Although we have consistently applied the same methods in developing the assumptions and estimates that underlie the fair value calculations, such as estimates of future cash flows, and based those estimates on relevant information available at the time, such cash flow estimates are highly uncertain by nature and may vary significantly from actual results. If the estimates of future cash flows used in the most recent tests had been 10% lower, the resulting fair values would have still been greater than the carrying values of each of those reporting units tested, indicating that no impairment was present.

Use of Estimates in Long-lived Asset Impairment Testing

Impairment testing for an individual or group of long-lived assets or for intangible assets with definite lives is required when circumstances indicate those assets may be impaired. When an asset's carrying amount exceeds the undiscounted estimated future cash flows associated with the asset, the asset is considered impaired to the extent that the asset's fair value is less than its carrying amount. Performing an impairment test on long-lived assets involves judgment in areas such as identifying circumstances that indicate an impairment may exist; identifying and grouping affected assets; and developing the undiscounted and discounted estimated future cash flows (used to estimate fair value in the absence of market-based value) associated with the asset, including probability weighting such cash flows to reflect expectations about possible variations in their amounts or timing and the selection of an appropriate discount rate. Although our cash flow estimates are based on relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. For example, estimates of future cash flows would contemplate factors, which may change over time, 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 the third quarter of 2008, we tested SO_2 emissions allowances held for consumption, with a carrying amount of $144 million, as a result of a decline in the market value of such allowances resulting from the July 2008 D.C. Appeals Court decision vacating CAIR that affected certain emission allowance surrender ratios. Based on the results of our test, including an analysis of recoverability through undiscounted cash flows from plant operations, no impairment charges were recognized. In December 2008, the Court issued a decision to reinstate CAIR that resulted in an increase in the market value of SO_2 allowances.

In 2006, we tested Dresden for impairment and concluded that its carrying amount, as well as the estimated cost to complete, was recoverable based on the probability of continued construction and use at that time. As part of our ongoing asset review to improve Dominion's return on invested capital, we began the process of exploring the sale of Dresden in the second quarter of 2007. Non-binding indicative bids were received and based on our evaluation of these bids, we believed that it was likely that Dresden would be sold rather than completed and operated in our merchant fleet. This change in intended use represented a triggering event for us to evaluate whether we could recover the carrying amount of our investment in Dresden. This analysis indicated that the carrying amount of Dresden would not be recovered. As a result, in the second quarter of 2007, we recognized a $387 million ($252 million after-tax) impairment charge to reduce Dresden's carrying amount to its estimated fair value in connection with the planned sale of Dresden, which closed in September 2007.

In 2005, we tested gas and steam electric turbines held for future development with a carrying amount of $187 million for impairment and concluded that the carrying amount was recoverable based upon the probability of future development as a merchant generation project at that time. In the third quarter of 2007, we recognized an $18 million impairment charge ($12 million after-tax) for two of these gas turbines that were sold by our merchant generation operations to our utility generation operations based upon amounts to be recovered by our utility in jurisdictional rate base. These turbines were used in the Ladysmith expansion project discussed under *Dominion Generation—Properties* in *Item 1. Business.*

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

ACCOUNTING FOR REGULATED OPERATIONS

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

As discussed further in Note 2 to our Consolidated Financial Statements, in April 2007, the Virginia General Assembly passed legislation that returned the Virginia jurisdiction of our utility generation operations to cost-of-service rate regulation. As a result, we reapplied the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, to those operations on April 4, 2007, the date the legislation was enacted. The reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations resulted in a $259 million ($158 million after tax) extraordinary charge and the reclassification of $195 million ($119 million after tax) of unrealized gains from AOCI related to nuclear decommissioning trust funds. This established a $454 million long-term regulatory liability for amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our utility nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations*. In connection with the reapplication of SFAS No. 71, we prospectively changed certain of our accounting policies for the Virginia jurisdiction of our utility generation operations to those used by cost-of-service rate-regulated entities. Other than the extraordinary item previously discussed, the overall impact of these changes was not material to our results of operations or financial condition in 2007.

We evaluate whether or not recovery of our regulatory assets through future rates is probable and make various assumptions in our analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions or historical experience, as well as discussions with applicable regulatory authorities. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made. In 2006, we wrote off $166 million of our regulatory assets as a result of the planned sale of Peoples and Hope to Equitable since the recovery of those assets was no longer probable. In January 2008, Dominion and Equitable announced the termination of that agreement, primarily due to the continued delays in achieving final regulatory approvals. We continued to seek other offers for the purchase of these utilities. In July 2008, we announced that we entered into an agreement with BBIFNA to sell Peoples and Hope and recognized a benefit of $47 million due to the re-establishment of certain of these regulatory assets, which we now expect to be recovered through future rates. We currently believe the recovery of our remaining regulatory assets is probable. See Notes 2, 5 and 14 to our Consolidated Financial Statements.

ASSET RETIREMENT OBLIGATIONS

We recognize liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These asset retirement obligations (AROs) are recognized at fair value as incurred, and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, we estimate the fair value of our AROs using present value techniques, in which we make various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. AROs currently reported in our Consolidated Balance Sheets were measured during a period of historically low interest rates. The impact on measurements of new AROs or remeasurements of existing AROs, using different cost escalation rates in the future, may be significant. When we revise any assumptions used to calculate the fair value of existing AROs, we adjust the carrying amount of both the ARO liability and the related long-lived asset. We accrete the ARO liability to reflect the passage of time. In 2008, 2007 and 2006, we recognized $94 million, $99 million and $109 million, respectively, of accretion, and expect to incur $99 million in 2009. Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, we began recording accretion and depreciation associated with utility nuclear decommissioning AROs, formerly charged to expense, as an adjustment to the regulatory liability for nuclear decommissioning trust funds previously discussed, in order to match the recognition for rate-making purposes.

A significant portion of our AROs relates to the future decommissioning of our nuclear facilities. At December 31, 2008, nuclear decommissioning AROs, which are reported in the Dominion Generation segment, totaled $1.6 billion, representing approximately 85% 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 utilize periodic site-specific base year cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our utility and merchant nuclear plants. We obtained updated cost studies for all of our nuclear plants in 2006 which generally reflected increases in base year costs. These cost studies were based on relevant information available at the time they were performed; however, estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results. In addition, our cost estimates include cost escalation rates that are applied to the base year costs. The selection of these cost escalation rates is dependent on subjective factors which we consider to be a critical assumption.

We determine cost escalation rates, which represent projected cost increases over time, due to both general inflation and increases in the cost of specific decommissioning activities, for each of our nuclear facilities. The use of alternative rates could have been material to the liabilities recognized. For example, had we increased the cost escalation rate by 0.5%, the amount recognized as of December 31, 2008 for our AROs related to nuclear decommissioning would have been $290 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 projected costs of providing benefits under these plans are dependent, in part, on historical information such as employee demographics, the level of contributions made to the plans and earnings on plan assets. Assumptions about the future, including the expected long-term 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 of changes in these factors, as well as differences between our assumptions and actual experience, is generally recognized in our Consolidated Statements of Income over the remaining average service period of plan participants, rather than immediately.

The expected long-term rates of return on plan assets, discount rates and healthcare 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, asset volatilities and correlations;
- 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 funds is 34% U.S. equity securities, 12% non-U.S. equity securities, 22% debt securities, 7% real estate and 25% other, such as private equity investments.

Strategic investment policies are established for each of our prefunded benefit plans based upon periodic asset/liability studies. Factors considered in setting the investment policy include those mentioned above such as employee demographics, liability growth rates, future discount rates, the funded status of the plans and the expected long-term rate of return on plan assets. Deviations from the plans' strategic allocation are a function of our assessments regarding short-term risk and reward opportunities in the capital markets and/or short-term market movements which result in the plans' actual asset allocations varying from the strategic target asset allocations. Through periodic rebalancing, actual allocations are brought back in line with the target.

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 long-term rate of return on plan assets assumption of 8.50% for 2008 and 8.75% for 2007 and 2006. We calculated our other postretirement benefit cost using an expected long-term rate of return on plan assets assumption of 7.75% for 2008 and 8.00% for 2007 and 2006. The rate used in calculating other postretirement benefit cost is lower than the rate used in calculating pension cost because of differences in the relative amounts of various types of investments held as plan assets.

We determine discount rates from analyses of AA/Aa rated bonds with cash flows matching the expected payments to be made under our plans. The discount rates used to calculate pension cost and other postretirement benefit cost were 6.60% and 6.50%, respectively, in 2008, compared to 6.20% and 6.10%, respectively, in 2007, and 5.60% and 5.50%, respectively, in 2006. Higher long-term bond yields were the primary reason for the increase in the discount rate from 2007 to 2008. We selected a discount rate of 6.60% for determining our December 31, 2008 projected pension and other postretirement benefit obligations.

We establish the healthcare cost trend rate assumption based on analyses of various factors including the specific provisions of our medical plans, actual cost trends experienced and projected, and demographics of plan participants. Our healthcare cost trend rate assumption as of December 31, 2008 is 9.00% and is expected to gradually decrease to 4.90% by 2059 and continue at that rate for years thereafter.

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

		Increase in Net Periodic Cost	
(millions, except percentages)	Change in Actuarial Assumption	Pension Benefits	Other Postretirement Benefits
Discount rate	**(0.25)%**	**$13**	**$ 6**
Long-term rate of return on plan assets	**(0.25)%**	**12**	**2**
Healthcare cost trend rate	**1.00%**	**N/A**	**23**

In addition to the effects on cost, at December 31, 2008, a 0.25% decrease in the discount rate would increase our projected pension benefit obligation by $120 million and our accumulated postretirement benefit obligation by $46 million, while a 1.00% increase in the healthcare cost trend rate would increase our accumulated postretirement benefit obligation by $194 million. See Note 22 to our Consolidated Financial Statements for additional information on our employee benefit plans.

ACCOUNTING FOR GAS AND OIL OPERATIONS

We follow the full cost method of accounting for gas and oil E&P activities prescribed by the SEC. Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized and subsequently depleted using the units-of-production method. The depletable base of costs includes estimated future costs to be incurred in developing proved gas and oil reserves, as well as capitalized asset retirement costs, net of projected salvage values. Capitalized costs in the depletable base are subject to a ceiling test prescribed by the SEC. The test limits capitalized amounts to a ceiling—the present value of estimated future net revenues to be derived from the production of proved gas and oil reserves, discounted at 10%, assuming period-end pricing adjusted for any cash flow hedges in place. We perform the ceiling test quarterly and would recognize asset impairments to the extent that total capitalized costs exceed the ceiling. Commodity prices have declined during the first quarter of 2009. If the current price environment continues, it could potentially result in a write-down of our natural gas and oil properties when we perform our March 31, 2009 quarterly ceiling test. While we cannot currently predict the impact of a ceiling test impairment on our results of operations, it would have no impact on our cash flows and we would not expect a material impact on our financial condition. 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. In 2007, we recognized gains from the sales of our Canadian and U.S. non-Appalachian E&P businesses. See Note 5 to our Consolidated Financial Statements for additional information on these sales.

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, 2008 are based upon studies for each of our properties prepared by our staff engineers and audited by Ryder Scott Company, L.P. Calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC guidelines. Given the volatility of natural gas and oil prices, it is possible that our estimate of discounted future net cash flows from proved natural gas and oil reserves that is used to calculate the ceiling could materially change in the near-term.

The process to estimate reserves is imprecise, and estimates are subject to revision. If there is a significant variance in any of our estimates or assumptions in the future and revisions to the value of our proved reserves are necessary, related depletion expense and the calculation of the ceiling test would be affected and recognition of natural gas and oil property impairments could occur. See Notes 2 and 27 to our Consolidated Financial Statements for additional information on our gas and oil producing activities.

Income Taxes

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

Prior to 2007, we established liabilities for tax-related contingencies when we believed it was probable that a liability had been incurred and the amount could be reasonably estimated in accordance with SFAS No. 5, *Accounting for Contingencies*, and subsequently reviewed them in light of changing facts and circumstances. However, as discussed in Note 3 to our Consolidated Financial Statements, effective January 1, 2007, we adopted FIN 48, *Accounting for Uncertainty in Income Taxes*. Taking into consideration the uncertainty and judgment involved in the determination and filing of income taxes, FIN 48 establishes standards for recognition and measurement, in financial statements, of positions taken, or expected to be taken, by an entity in its income tax returns. Positions taken by an entity in its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by tax authorities with full knowledge of all relevant information. If we take or expect to take a tax return position that is not recognized in the financial statements, we disclose such amount as an unrecognized tax benefit. At December 31, 2008 we had $404 million of unrecognized tax benefits. For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility.

Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. We evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized. At December 31, 2008, we had established $78 million of valuation allowances on our deferred tax assets.

Other

Accounting Standards and Policies

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

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

RESULTS OF OPERATIONS

Presented below is a summary of our consolidated results:

Year Ended December 31,	2008	$ Change	2007	$ Change	2006
(millions, except EPS)					
Net Income	$1,834	$ (705)	$2,539	$1,159	$1,380
Diluted EPS	3.16	(0.72)	3.88	1.92	1.96

Overview

2008 vs. 2007

Net income decreased by 28% to $1.8 billion. Unfavorable drivers include the absence of a $2.1 billion after-tax gain on the sale of our U.S. non-Appalachian E&P business and the absence of ongoing earnings from this business due to the sale. Favorable drivers include the absence of the following items incurred in 2007:

- Charges related to the sale of the majority of our E&P operations;
- An impairment charge related to the sale of Dresden;
- An extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations; and
- A charge in connection with the termination of a long-term power sales agreement at State Line.

Additional favorable drivers include the reinstatement of annual fuel rate adjustments for the Virginia jurisdiction of our utility generation operations effective July 1, 2007, a higher contribution from our merchant generation operations and the reversal of deferred tax liabilities associated with the planned sale of Peoples and Hope. Diluted EPS decreased to $3.16 and includes $0.36 of share accretion resulting from the repurchase of shares in 2007 with proceeds received from the sale of the majority of our E&P operations.

2007 vs. 2006

Net income increased by 84% to $2.5 billion. Diluted EPS increased to $3.88 and includes $0.24 of share accretion resulting from the repurchase of shares with proceeds received from the sale of our non-Appalachian E&P business. Favorable drivers include a gain on the sale of our non-Appalachian E&P business, higher realized prices for our gas and oil production, higher margins at our merchant generation business and the reinstatement of annual fuel rate adjustments for the Virginia jurisdiction of our utility generation operations. Unfavorable drivers include a decrease in gas and oil production due to the sale of our non-Appalachian E&P business, an impairment charge related to the sale of Dresden, an extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, charges related to the early extinguishment of outstanding debt associated with the completion of our debt tender offer in July 2007, a charge due to the discontinuance of hedge accounting for certain gas and oil derivatives and subsequent changes in the fair value of these derivatives as a result of the sale of our non-Appalachian E&P business, a charge for the termination of a long-term power sales agreement at State Line and the absence of business interruption insurance revenue received in 2006, associated with Hurricanes Katrina and Rita (2005 hurricanes).

Analysis of Consolidated Operations

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

Year Ended December 31,	2008	$ Change	2007	$ Change	2006
(millions)					
Operating Revenue	$16,290	$1,474	$14,816	$(2,460)	$17,276
Operating Expenses					
Electric fuel and energy purchases	3,963	592	3,371	276	3,095
Purchased electric capacity	411	(28)	439	(42)	481
Purchased gas	3,398	623	2,775	(794)	3,569
Other energy-related commodity purchases	60	(192)	252	(770)	1,022
Other operations and maintenance	3,257	(868)	4,125	519	3,606
Gain on sale of U.S. non-Appalachian E&P business	42	3,677	(3,635)	(3,635)	—
Depreciation, depletion and amortization	1,034	(334)	1,368	(189)	1,557
Other taxes	499	(53)	552	(16)	568
Other income (loss)	(58)	(160)	102	(71)	173
Interest and related charges	853	(324)	1,177	89	1,088
Income tax expense	879	(904)	1,783	856	927
Loss from discontinued operations, net of tax	(2)	6	(8)	142	(150)
Extraordinary item, net of tax	—	158	(158)	(158)	—

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

2008 vs. 2007

Operating Revenue increased 10% to $16.3 billion, primarily reflecting:

- A $753 million increase in revenue from our electric utility operations resulting primarily from an increase in fuel revenue largely due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;
- A $626 million increase from merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations ($500 million) and the absence of a charge related to the termination of a long-term power sales agreement at State Line in 2007 ($231 million), partially offset by lower overall volumes due to outages at certain fossil and nuclear generating facilities ($105 million);
- A $330 million increase in our producer services business primarily as a result of higher realized prices for natural gas aggregation activities and favorable price changes associated with natural gas trading activities;

- A $129 million increase in sales of gas production from our remaining E&P operations, primarily due to:
  - A $70 million increase in sales from our Appalachian properties due to higher prices ($51 million) and increased production ($19 million); and
  - Increased production associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007 ($59 million);
- A $133 million increase in regulated gas sales attributable to our gas distribution operations primarily resulting from the impact of higher prices;
- A $131 million increase in nonregulated gas sales by our gas distribution operations, primarily due to the sale of gas inventory by Dominion East Ohio related to its plan to exit the gas merchant function in Ohio and have all customers select an alternate gas supplier;
- A $117 million increase in gas sales by retail energy marketing operations primarily due to higher prices;
- A $109 million increase in gas transportation and storage revenue primarily due to a $66 million increase in revenue from our gas distribution operations due to higher prices ($52 million) and increased volumes ($14 million) and a $43 million increase attributable to our gas transmission operations primarily reflecting increased transport and storage activities and gathering and extraction services;
- A $76 million increase in electricity sales by retail energy marketing operations due to higher sales prices ($54 million) and the acquisition of an additional retail business in September 2008 ($69 million), partially offset by lower volumes ($47 million); and
- A $44 million increase in sales of extracted products from our gas transmission operations as a result of higher realized prices;

These increases were partially offset by:

- A $716 million decrease due to the sale of the majority of our U.S. E&P operations in 2007, reflecting the absence of $1.4 billion of revenue from these operations, partially offset by the absence of a $541 million charge predominantly due to the discontinuance of hedge accounting for certain gas and oil derivatives and subsequent changes in the fair value of these derivatives; and a $171 million charge primarily due to the termination of VPP agreements in connection with the sale; and
- A $179 million decrease in nonutility coal sales primarily related to exiting this activity.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 18% to $4.0 billion, primarily reflecting the combined effects of:

- A $321 million increase for our utility generation operations. This increase was largely due to a $434 million increase in fuel costs, primarily as a result of higher commodity prices, including purchased power. The increase in fuel costs was partially offset by the deferral of fuel expenses that were in excess of the fuel rate recovery ($113 million);
- A $126 million increase for our merchant generation operations primarily reflecting the impact of higher commodity prices ($54 million) and increased fuel consumption ($72 million) at certain fossil generation facilities; and
- A $111 million increase from retail energy marketing operations due to higher prices ($86 million) and increased expenses due to the acquisition of an additional retail business ($55 million), partially offset by lower volumes ($30 million).

Purchased gas expense increased 22% to $3.4 billion, primarily due to the following factors:

- A $274 million increase for our producer services business primarily as a result of an increase in prices associated with natural gas aggregation and marketing activities;
- A $247 million increase in the cost of gas sold by our gas distribution operations primarily reflecting the combined effects of the following:
  - A $129 million increase in volumes primarily due to the net impact of the sale of gas inventory by Dominion East Ohio related to its plan to exit the gas merchant function in Ohio and have all customers select an alternate gas supplier partially offset by lower sales for our regulated gas distribution operations; and
  - A $118 million increase due to higher prices; and
- A $120 million increase in the cost of gas sold by retail energy marketing operations due to higher prices; partially offset by
- A $60 million decrease due to the sale of the majority of our U.S. E&P operations.

Other energy-related commodity purchases expense decreased 76% to $60 million, primarily due to a $194 million decrease in the cost of nonutility coal sales related to exiting this activity.

Other operations and maintenance expense decreased 21% to $3.3 billion, primarily reflecting the combined effects of:

- A $443 million decrease reflecting the sale of the majority of our U.S. E&P operations, including the absence of charges incurred in 2007 in connection with the sale;
- The absence of a $387 million impairment charge in 2007 related to the sale of Dresden; and
- The absence of $54 million of litigation-related charges in 2007.

Gain on sale of U.S. non-Appalachian E&P business primarily reflects the absence of the gain of $3.6 billion resulting from the completion of the sale of our U.S. non-Appalachian E&P business in 2007.

DD&A decreased 24% to $1.0 billion, principally due to decreased gas and oil production resulting from the sale of the majority of our U.S. E&P operations in 2007, partially offset by an increase in rates and production from our remaining E&P operations, property additions and an increase in depreciation rates for our utility generation assets.

Other taxes decreased 10% to $499 million primarily due to lower severance and property taxes resulting from the sale of the majority of our U.S. E&P operations in 2007.

Other income (loss) was a loss of $58 million in 2008 as compared to income of $102 million in 2007, primarily due to higher other-than-temporary impairments for nuclear decommissioning trust investments.

Interest and related charges decreased 28% to $853 million, resulting principally from the absence of charges related to the early extinguishment of outstanding debt associated with our debt tender offer completed in July 2007 and lower interest rates on variable rate debt.

Income tax expense decreased by 51% to $879 million, primarily due to lower pre-tax income in 2008 largely reflecting the absence of the gain realized in 2007 from the sale of our U.S. non-Appalachian E&P business.

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

2007 vs. 2006

Operating Revenue decreased 14% to $14.8 billion, primarily reflecting:

- A $665 million decrease in our producer services business largely due to the net impact of a decrease in economic hedging activity ($612 million) and a decrease in physical realized prices ($113 million), partially offset by an increase in physical realized volumes ($60 million), all associated with natural gas aggregation and marketing activities;
- A $632 million decrease in sales of gas and oil production primarily due to lower volumes due to the sale of our U.S. non-Appalachian E&P business;
- A $541 million decrease predominantly due to the discontinuance of hedge accounting for certain gas and oil derivatives and subsequent changes in the fair value of these derivatives as a result of the sale of our U.S. non-Appalachian E&P business;
- A $422 million decrease in revenue from sales of oil purchased by E&P operations, primarily due to the impact of netting sales and purchases of oil under buy/sell arrangements associated with the implementation of EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, in 2006, as discussed in Note 3 to our Consolidated Financial Statements;
- A $309 million decrease in nonutility coal sales, primarily from reduced sales volumes ($281 million) related to exiting certain sales activities and lower prices ($28 million);
- A $273 million decrease reflecting the absence of business interruption insurance revenue received in 2006, associated with the 2005 hurricanes;
- A $231 million charge related to the termination of a long-term power sales agreement at State Line;
- A $222 million decrease in regulated gas sales by our gas distribution operations reflecting the combined effects of:
  - A $185 million decrease reflecting lower gas prices; and
  - A $198 million decrease resulting from the migration of customers to energy choice programs; partially offset by
  - A $161 million increase in volumes due to an increase in the number of heating degree days, primarily in the first quarter of 2007, and changes in customer usage patterns and other factors;
- A $171 million decrease primarily due to the termination of VPP agreements as a result of the sale of our U.S. non-Appalachian E&P business. We have retained the repurchased fixed-term overriding royalty interests formerly associated with these agreements; and
- A $65 million decrease in nonregulated gas sales by our gas distribution operations primarily due to a decrease in volumes;

These decreases were partially offset by:

- A $581 million increase in revenue from our electric utility operations, largely resulting from:
  - A $166 million increase due to the impact of a comparatively higher fuel rate implemented in July 2007 for certain customer jurisdictions;
  - A $162 million increase in sales to retail customers attributable to variations in rates resulting from changes in sales mix and other factors ($95 million) and new customer connections ($67 million) primarily in our residential and commercial customer classes;
  - A $131 million increase in sales to retail customers due to an increase in the number of cooling and heating degree days. As compared to the prior year, we experienced a 15% increase in cooling degree days and a 10% increase in heating degree days;
  - An $80 million increase in sales to wholesale customers; and
  - A $42 million increase resulting primarily from higher ancillary service revenue reflecting higher regulation and operating reserves revenue received from PJM;
- A $508 million increase for merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations ($354 million), including higher capacity revenue associated with new capacity markets in ISO New England and PJM, and increased volumes for fossil operations ($154 million);
- A $139 million increase in gas sales by retail energy marketing operations due to increased customer accounts ($189 million), partially offset by lower contracted sales prices ($50 million); and
- An $88 million increase in gas transportation and storage revenue primarily attributable to our gas distribution operations due to increased volumes and higher prices.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 9% to $3.4 billion, primarily reflecting the combined effects of:

- A $128 million increase for utility generation operations. The underlying fuel costs, including those subject to deferral accounting, increased by approximately $536 million due to higher consumption of fossil fuel and purchased power resulting from an increase in the number of heating and cooling degree days, higher commodity costs and a change in generation mix. This increase was largely offset by a $408 million decrease primarily due to the deferral of fuel expenses that were in excess of current period fuel rate recovery;
- An $85 million increase for our merchant generation operations primarily due to higher commodity prices and increased fossil fuel consumption; and
- A $40 million increase related to our retail energy marketing operations primarily due to higher volumes ($22 million) and prices ($18 million).

Purchased gas expense decreased 22% to $2.8 billion, primarily due to the following factors:

- A $594 million decrease associated with our producer services business largely due to a decrease in economic hedging for natural gas aggregation and marketing activities;
- A $247 million decrease in costs attributable to gas distribution operations primarily due to lower prices ($225 million) and volumes ($22 million); and
- A $97 million decrease related to gas purchased by our E&P operations to facilitate gas transportation and other contracts primarily due to the implementation of EITF 04-13, as discussed in Note 3 to our Consolidated Financial Statements;

These decreases were partially offset by:

- An \$85 million increase associated with retail energy marketing operations, due to higher volumes (\$168 million), partially offset by lower prices (\$83 million).

Other energy-related commodity purchases expense decreased 75% to \$252 million, primarily attributable to the following factors:

- A \$409 million decrease related to commodity purchases by our E&P operations to facilitate gas transportation and other contracts primarily due to the implementation of EITF 04-13;
- A \$310 million decrease in the cost of nonutility coal sales related to exiting this activity; and
- A \$51 million decrease in the cost of sales of emissions allowances held for resale.

Other operations and maintenance expense increased 14% to \$4.1 billion, resulting primarily from:

- A \$387 million impairment charge related to the sale of Dresden;
- A \$124 million increase in salaries, wages and benefits expense primarily resulting from higher incentive-based compensation (\$100 million) and higher salaries and wages (\$83 million), partially offset by lower pension and healthcare benefits expense (\$59 million);
- A \$96 million increase in outage costs, primarily related to scheduled outages for both utility and merchant generation operations;
- A \$54 million increase due to a decrease in gains from the sale of emissions allowances held for consumption; and
- A \$54 million increase resulting from litigation-related charges; partially offset by
- The absence of a \$166 million charge in 2006 related to the write-off of certain regulatory assets in connection with the planned sale of Peoples and Hope.

Gain on sale of U.S. non-Appalachian E&P business reflects a pre-tax gain of \$3.6 billion resulting from the completion of the sale of our U.S. non-Appalachian E&P business.

DD&A decreased 12% to \$1.4 billion, principally due to decreased oil and gas production resulting from the sale of our U.S. non-Appalachian E&P business (\$297 million); partially offset by an increase in DD&A rates for our remaining Appalachian E&P business (\$124 million).

Other income decreased 41% to \$102 million, resulting primarily from the recognition of decommissioning trust earnings as a regulatory liability due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, as well as an increase in charitable contributions.

Interest and related charges increased 8% to \$1.2 billion, resulting principally from charges related to the early extinguishment of outstanding debt associated with our debt tender offer completed in July 2007, partially offset by a reduction in interest expense resulting from the retirement of this and other debt and the absence of a \$60 million charge in 2006 due to the elimination of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts.

Income tax expense increased to \$1.8 billion, primarily reflecting income tax expense on the gain realized from the sale of our U.S. non-Appalachian E&P business.

Loss from discontinued operations decreased to \$8 million primarily reflecting the absence of a \$164 million after-tax charge in 2006 related to the Peaker facilities, which were sold in 2007.

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

Outlook

In order to deliver favorable returns to investors, Dominion's strategy is to focus on its regulated businesses while maintaining upside potential in well-positioned nonregulated businesses. The goals of this "regulated plus" model are to provide earnings per share growth, a growing dividend and stable credit ratings. In 2009, 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. Our expected results for 2009 include the following growth factors:

- Higher earnings from Dominion East Ohio as a result of a base rate increase approved in the fourth quarter of 2008;
- An increase in earnings from our merchant generation operations primarily reflecting higher realized prices for energy and capacity, and one less outage at our Millstone power station;
- Higher earnings from our LNG and gas transmission and storage operations, reflecting expansion projects at our Cove Point LNG terminal and DTI pipeline system that were completed in December 2008; and
- An increase in earnings from our electric utility operations assuming an increase in base rates resulting from the 2009 base rate review, normal weather in our utility service territory, rate adjustments for certain generation and transmission expansion projects and continued growth in sales. Despite the recent economic downturn we expect continued growth in sales due to several factors including our limited exposure to industrial customers, an unemployment rate in Virginia that is below the national average, a growing number of energy-intensive computer data centers and significant government presence in our Northern Virginia service territory and U.S. military base closures and reassignments that have resulted in personnel being shifted to facilities in Virginia such as Fort Lee and Fort Belvoir.

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

- Higher interest expense reflecting difficult credit market conditions;
- An increase in pension and other postretirement benefit costs, largely reflecting the impact of 2008 declines in the market values of investments held to fund these obligations;
- The impact of lower commodity prices on the market prices received for our unhedged natural gas production; and
- A decline in production from fixed-term overriding royalty interests formerly associated with our VPP agreements, reflecting the expiration of these interests in February 2009.

See *Impact of Recent Credit Market Events* in *Liquidity and Capital Resources* for additional factors that may influence our results.

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,	2008		2007		2006	
	Net Income	**Diluted EPS**	Net Income	Diluted EPS	Net Income	Diluted EPS
(millions, except EPS)						
DVP	**$ 380**	**$ 0.65**	$ 415	$0.64	$ 411	$0.59
Dominion Energy	**468**	**0.81**	387	0.59	347	0.49
Dominion Generation	**1,227**	**2.11**	756	1.15	537	0.76
Primary operating segments	**2,075**	**3.57**	1,558	2.38	1,295	1.84
Corporate and Other	**(241)**	**(0.41)**	981	1.50	85	0.12
Consolidated	**$1,834**	**$ 3.16**	$2,539	$3.88	$1,380	$1.96

DVP

Presented below are operating statistics related to DVP's operations:

Year Ended December 31,	**2008**	**% Change**	2007	% Change	2006
Electricity delivered (million mwhrs)(1)	**84.0**	**(1)%**	84.7	6%	79.8
Degree days:					
Cooling(2)	**1,621**	**(10)**	1,794	15	1,557
Heating(3)	**3,426**	**(2)**	3,500	10	3,178
Average electric distribution customer accounts (thousands)(4)	**2,386**	**1**	2,361	1	2,327
Average retail energy marketing customer accounts (thousands)(4)	**1,601**	**3**	1,551	15	1,354

(1) Includes electricity delivered through the retail choice program for our Virginia jurisdictional electric utility customers.
(2) Cooling degree days are units measuring the extent to which the average daily temperature is greater than 65 degrees, and are calculated as the difference between 65 degrees and the average temperature for that day.
(3) Heating degree days are units measuring the extent to which the average daily temperature is less than 65 degrees, and are calculated as the difference between 65 degrees and the average temperature for that day.
(4) Thirteen-month average.

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

2008 vs. 2007

	Increase (Decrease)	
	Amount	**EPS**
(millions, except EPS)		
Regulated electric sales:		
Weather	**$(14)**	**$(0.03)**
Customer growth	**9**	**0.01**
Other	**(9)**	**(0.01)**
Storm damage and service restoration—distribution operations(1)	**(10)**	**(0.02)**
Interest expense	**(9)**	**(0.01)**
Retail energy marketing operations	**(2)**	**(0.01)**
Share accretion	**—**	**0.08**
Change in net income contribution	**$(35)**	**$ 0.01**

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

2007 vs. 2006

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	$ 22	$ 0.03
Customer growth	11	0.02
Storm damage and service restoration—distribution operations(1)	9	0.01
Reliability and outside services expenses	(18)	(0.02)
Salaries, wages and benefits expense	(15)	(0.02)
Other	(5)	(0.01)
Share accretion	—	0.04
Change in net income contribution	$ 4	$ 0.05

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

Dominion Energy

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

Year Ended December 31,	2008	% Change	2007	% Change	2006
Gas distribution throughput (bcf):					
Sales	**50**	**—%**	50	(11)%	56
Transportation	**216**	**3**	210	9	193
Heating degree days	**6,162**	**5**	5,886	12	5,274
Average gas distribution customer accounts (thousands)(1):					
Sales	**388**	**(5)**	410	(15)	485
Transportation	**814**	**2**	800	9	732
Production(2) (bcfe)	**64.6**	**12**	57.6	47	39.1
Average realized prices without hedging results (per mcfe)	**$ 8.73**	**33**	$ 6.55	(8)	$ 7.11
Average realized prices with hedging results (per mcfe)	**8.50**	**30**	6.55	33	4.93
DD&A (unit of production rate per mcfe)	**1.93**	**15**	1.68	31	1.28
Average production (lifting) cost (per mcfe)(3)	**1.37**	**7**	1.28	8	1.19

(1) Thirteen-month average.
(2) Includes natural gas, natural gas liquids and oil. Production includes 17.8 bcfe and 15.5 bcfe for 2008 and 2007, respectively, associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007.
(3) The inclusion of volumes associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007 would have resulted in lifting costs of $1.11 and $1.00 for 2008 and 2007, respectively.

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

2008 vs. 2007

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Gas and oil—prices	**$ 44**	**$ 0.07**
Gas and oil—production(1)	**40**	**0.06**
DD&A—gas and oil	**(17)**	**(0.03)**
Producer services	**(6)**	**(0.01)**
Other	**20**	**0.04**
Share accretion	**—**	**0.09**
Change in net income contribution	**$ 81**	**$ 0.22**

(1) Primarily reflects an increase in volumes associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007.

2007 vs. 2006

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Gas and oil—production	$ 66	$ 0.10
Gas and oil—prices	33	0.05
Regulated gas sales—weather	16	0.02
Producer services(1)	(33)	(0.05)
DD&A—gas and oil	(27)	(0.04)
Salaries, wages and benefits expense	(7)	(0.01)
Gas transmission operations(2)	(6)	(0.01)
Other	(2)	—
Share accretion	—	0.04
Change in net income contribution	$ 40	$ 0.10

(1) Primarily related to lower margins reflecting reduced market volatility, as compared to the post-2005 hurricane market conditions in 2006.
(2) Gas transmission operations decreased primarily due to a decline in market center services, partially offset by lower system fuel costs and higher margins on extracted products.

Included below are the volumes and weighted-average prices associated with hedges in place for our Appalachian E&P operations and fixed-term overriding royalty interests formerly associated with the VPP agreements as of December 31, 2008, by applicable time period.

	Natural Gas	
Year	Hedged production (bcf)	Average hedge price (per mcf)
2009	**31.8**	**$9.08**
2010	**14.8**	**8.62**
2011	**1.4**	**7.36**

Dominion Generation

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

Year Ended December 31,	2008	% Change	2007	% Change	2006
Electricity supplied (million mwhrs):					
Utility	**84.0**	**(1)%**	84.7	6%	79.7
Merchant	**45.3**	**(2)**	46.0	11	41.5
Degree days (electric utility service area):					
Cooling	**1,621**	**(10)**	1,794	15	1,557
Heating	**3,426**	**(2)**	3,500	10	3,178

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

2008 vs. 2007

	Increase (Decrease)	
	Amount	**EPS**
(millions, except EPS)		
Virginia fuel expenses(1)	**$243**	**$ 0.37**
Merchant generation margin(2)	**174**	**0.27**
Interest expense	**41**	**0.06**
Depreciation and amortization	**(37)**	**(0.06)**
Regulated electric sales:		
Weather	**(27)**	**(0.04)**
Customer growth	**16**	**0.03**
Other(3)	**26**	**0.04**
Other	**35**	**0.05**
Share accretion	**—**	**0.24**
Change in net income contribution	**$471**	**$ 0.96**

(1) Primarily reflects the reapplication of deferred fuel accounting effective July 1, 2007 for the Virginia jurisdiction of our utility generation operations.
(2) Primarily reflects higher realized prices, partially offset by higher fuel costs and lower volumes at certain generation facilities due to outages.
(3) Primarily reflects higher margins associated with sales to wholesale customers.

2007 vs. 2006

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Merchant generation margin(1)	$211	$ 0.30
Virginia fuel expenses(2)	120	0.17
Regulated electric sales:		
Weather	37	0.05
Customer growth	20	0.03
Ancillary service revenue	27	0.04
Outage costs(3)	(61)	(0.09)
Salaries, wages and benefits expense	(51)	(0.07)
Sales of emissions allowances	(34)	(0.05)
Depreciation and amortization(4)	(32)	(0.05)
Interest expense	(9)	(0.01)
Other	(9)	(0.01)
Share accretion	—	0.08
Change in net income contribution	$219	$ 0.39

(1) Primarily reflects higher realized prices for our New England nuclear and fossil generating assets and higher volumes and capacity revenue for other fossil generation operations. Higher prices include the implementation of new capacity markets in ISO New England and PJM.
(2) Primarily reflects the reapplication of deferred fuel accounting effective July 1, 2007 for the Virginia jurisdiction of our utility generation operations; partially offset by increased consumption of fossil fuel and higher purchased power costs during the first six months of 2007.
(3) Primarily reflects higher scheduled outage costs for both utility and merchant generation operations.
(4) Principally attributable to increased expense from capital additions and revised depreciation rates for our utility generation assets resulting from a new depreciation study implemented during the fourth quarter of 2007.

Corporate and Other

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

Year Ended December 31,	**2008**	2007	2006
(millions, except EPS amounts)			
Specific items attributable to operating segments	**$ (137)**	$ (618)	$ (10)
Discontinued operations	**(2)**	(8)	(150)
Sale of U.S. E&P business	**(26)**	1,426	(5)
Divested U.S. E&P operations	**—**	252	625
Peoples and Hope	**78**	49	(72)
Other corporate operations	**(154)**	(120)	(303)
Total net benefit (expense)	**$ (241)**	$ 981	$ 85
Earnings per share impact	**$(0.41)**	$ 1.50	$0.12

Specific Items Attributable to Operating Segments

Corporate and Other includes specific items attributable to our primary operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or allocating resources among the segments. See Note 26 to our Consolidated Financial Statements for discussion of these items.

Discontinued Operations

The decrease in the loss from the discontinued operations for 2007 as compared to 2006 primarily reflects the impact of a $164 million after-tax charge in 2006 associated with the impairment of the Peaker facilities that were sold in 2007.

Sale of U.S. E&P Business

The sale of our U.S. non-Appalachian E&P business reflects the $2.1 billion after-tax gain recognized in 2007 on the sale, partially offset by charges related to the divestitures as well as charges associated with the early retirement of debt with proceeds from the sale. The 2008 amount reflects post-closing adjustments to the gain on the sale. See Note 5 to our Consolidated Financial Statements for discussion of these items.

Divested U.S. E&P Operations

The lower contribution in 2007 as compared to 2006 is due primarily to a partial year of gas and oil production in 2007 as compared to 2006 and the absence of business interruption insurance revenue received in 2006, associated with the 2005 hurricanes. These decreases were partially offset by higher realized gas and oil prices.

Peoples and Hope

The increased net benefit in 2008 primarily reflects a $47 million ($28 million after tax) benefit from the re-establishment of certain regulatory assets in connection with the agreement to sell these subsidiaries to BBIFNA. Regulatory assets of $166 million ($104 million after tax) were previously written off in 2006 in connection with the previous sales agreement with Equitable. See Notes 5 and 7 to our Consolidated Financial Statements for discussion of these items.

Other Corporate Operations

The net expenses associated with other corporate operations for 2008 increased by $34 million as compared to 2007, primarily reflecting a decrease in tax benefits, higher interest expense and the absence of interest income earned on the proceeds received from the sale of our non-Appalachian E&P business in 2007. The decrease in tax benefits primarily reflects the net impact of the following items:

- A decrease in state tax benefits, including the impact of Massachusetts tax legislation enacted in July 2008; and
- The absence of tax benefits from the elimination of valuation allowances on federal and state tax loss carryforwards in 2007, partially offset by
- An increase in tax benefits due to the reversal of deferred tax liabilities associated with Peoples and Hope in the first quarter of 2008.

The increase in net expenses was partially offset by the impact of lower impairment charges in 2008 related to the disposition of certain DCI investments.

The net expenses associated with other corporate operations for 2007 decreased by $183 million as compared to 2006, primarily due to a reduction in interest expense following completion of the debt tender offer in July 2007, the absence of a charge in 2006 to eliminate the application of hedge accounting for certain interest rate swaps and a reduction in charges associated with the impairment of DCI investments. In addition, income tax benefits were lower in 2006, resulting primarily from the recognition of deferred tax liabilities in connection with the planned sale of Peoples and Hope.

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 electricity, natural gas and other energy-related products. 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 2008 follows:

(millions)	Amount
Net unrealized gain at December 31, 2007	$ 52
Contracts realized or otherwise settled during the period	**(39)**
Net unrealized gain at inception of contracts initiated during the period	—
Change in unrealized gains and losses	**30**
Changes in unrealized gains and losses attributable to changes in valuation techniques	—
Net unrealized gain at December 31, 2008	**$ 43**

The fair values summarized below were determined in accordance with the requirements of SFAS No. 157, which we adopted effective January 1, 2008. In addition, we aligned the categories below with the Level 1, 2, and 3 fair value measurements as defined by SFAS No. 157. The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at December 31, 2008, 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	Less than 1 year	1-2 years	2-3 years	3-5 years	In excess of 5 years	Total
(millions)						
Actively-quoted – Level 1[1]	**$ 2**	**$—**	**$—**	**$—**	**$—**	**$ 2**
Other external sources – Level 2[2]	**33**	**4**	**—**	**—**	**—**	**37**
Models and other valuation methods – Level 3[3]	**4**	**1**	**(1)**	**—**	**—**	**4**
Total	**$39**	**$ 5**	**$(1)**	**$—**	**$—**	**$43**

(1) Values represent observable unadjusted quoted prices for traded instruments in active markets.
(2) Values with inputs that are observable directly or indirectly for the instrument, but do not qualify for Level 1.
(3) Values with a significant amount of inputs that are not observable for the instrument.

Liquidity and Capital Resources

We depend on both internal and external sources of liquidity to provide working capital and to fund capital requirements. Short-term cash requirements not met by cash provided by operations are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through issuances of debt and/or equity securities.

At December 31, 2008, we had $2.9 billion of unused capacity under our credit facilities, excluding commitments provided by Lehman Brothers Holdings Inc. (Lehman). See additional discussion under *Credit Facilities and Short-Term Debt.*

A summary of our cash flows is presented below:

	2008	2007	2006
(millions)			
Cash and cash equivalents at beginning of year	**$ 287**	$ 142	$ 146
Cash flows provided by (used in):			
Operating activities	**2,659**	(246)	4,005
Investing activities	**(3,490)**	10,192	(3,494)
Financing activities	**615**	(9,801)	(515)
Net increase (decrease) in cash and cash equivalents	**(216)**	145	(4)
Cash and cash equivalents at end of year(1)	**$ 71**	$ 287	$ 142

(1) 2008 amount includes $5 million and 2007 and 2006 amounts include $4 million of cash classified as held for sale in the Consolidated Balance Sheets.

Impact of Recent Credit Market Events

Despite recent disruptions in the credit markets, we have sufficient access to liquidity for our daily operations through our credit facilities discussed in *Financing Cash Flows and Liquidity*. While we continue to issue commercial paper, in October 2008 we borrowed $870 million from our credit facilities to reduce our exposure to the commercial paper market. We expect our operations to provide sufficient cash flow to fund maintenance capital expenditures, maintain or grow our dividend and fund a portion of our growth capital expenditures; however, we expect to access the capital markets to fund the balance of our growth capital expenditures not covered by cash flow from operations. If necessary, we have the flexibility to mitigate the need for future debt financings and equity issuances, by postponing or cancelling certain planned capital expenditures, however, a material reduction or delay in growth projects would likely reduce our earnings per share growth rate longer term.

Given the increased interest rates and widespread economic pressures in the marketplace, we plan to conserve cash and lower our financing requirements. In December 2008, we announced that we plan to selectively reduce 2009 non-fuel operating and maintenance expenses, which will include work force management, contractor, consultant, advertising and non-utility maintenance reductions. In addition, we will reduce planned capital expenditures by approximately $350 million. We do not expect the planned reduction in spending to adversely impact safety or customer service. As a result of the reduction in spending and the impact of increasing costs of capital, increases in pension and other benefit costs as well as a decline in commodity prices, we now expect lower earnings per share growth in 2009 and 2010 than previously forecast. Despite projected increases in pension and other benefit costs, no contributions to our pension plans are currently expected in 2009 or 2010.

We do not expect to change our dividend policy in response to recent events in the credit markets. In fact, in December 2008, our Board of Directors approved a quarterly dividend of 43.75 cents per share to be paid in March 2009, raising the quarterly dividend approximately 11%, from the existing quarterly dividend rate of 39.5 cents per share. Stated as an annual rate, the Board's action increases the dividend rate from $1.58 per share in 2008 to $1.75 per share in 2009. The Board of Directors also reconfirmed a goal of achieving a 55% dividend payout ratio by 2010.

Operating Cash Flows

In 2008, net cash provided by operating activities was approximately $2.7 billion as compared to net cash used in operating activities of $246 million in 2007. This primarily reflects the absence of income taxes paid in 2007 on the gain from the sale of a majority of our E&P business, the benefit from the reinstatement of annual fuel rate adjustments for the Virginia jurisdiction of our utility generation operations effective July 1, 2007 and a higher contribution from our merchant generation business, partially offset by a reduction in cash flow resulting from the disposition of the majority of our E&P operations and unfavorable changes in working capital. While taxes and other costs of the sale in 2007 were reflected in cash flow from operations, the gross proceeds from the sale were reported in cash flow from investing activities.

Our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows which are discussed in Item 1A. Risk Factors.

Credit Risk

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

	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
(millions)			
Investment grade(1)	**$1,229**	**$348**	**$ 881**
Non-investment grade(2)	**12**	**—**	**12**
No external ratings:			
Internally rated—investment grade(3)	**289**	**2**	**287**
Internally rated—non-investment grade(4)	**22**	**—**	**22**
Total	**$1,552**	**$350**	**$1,202**

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody's and Standard & Poor's. The five largest counterparty exposures, combined, for this category represented approximately 42% of the total net credit exposure.

(2) The five largest counterparty exposures, combined, for this category represented less than 1% of the total net credit exposure.

(3) The five largest counterparty exposures, combined, for this category represented approximately 16% of the total net credit exposure.

(4) The five largest counterparty exposures, combined, for this category represented approximately 1% of the total net credit exposure.

Investing Cash Flows

In 2008, net cash used in investing activities was approximately $3.5 billion as compared to net cash provided by investing activities of $10.2 billion in 2007. This change is primarily due to the absence of the proceeds received in 2007 from the sales of our non-Appalachian E&P business and Peaker facilities, a reduction in capital expenditures as a result of the disposition of the majority of our E&P operations, and proceeds received from the assignment of drilling rights in the Marcellus Shale formation to Antero in 2008, partially offset by an increase in capital expenditures primarily related to our electric utility operations and our investment in wind farm facilities.

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 our operations. As discussed in *Credit Ratings*, our ability to borrow funds or issue securities and the return demanded by investors are affected by our credit ratings. In addition, the raising of external capital is subject to certain regulatory approvals, including registration with the SEC and, in the case of Virginia Power, approval by the Virginia Commission.

In December 2005, the SEC adopted the rules that currently govern the registration, communications and offering processes under the Securities Act of 1933 (Securities Act). The rules provide for a streamlined shelf registration process to provide registrants with timely access to capital. Under these rules, Dominion and Virginia Power meet the definition of a well-known seasoned issuer. This allows the companies to use an automatic shelf registration statement to register any offering of securities, other than those for business combination transactions.

In 2008, net cash provided by financing activities was $615 million as compared to net cash used in financing activities of $9.8 billion in 2007. This change is primarily due to net issuances of common stock and short-term and long-term debt in 2008 as compared to net repurchases and repayments in 2007 reflecting the use of proceeds received in 2007 from the sale of the majority of our E&P business.

Credit Facilities and Short-Term Debt

We use short-term debt to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, we utilize cash and letters of credit to fund collateral requirements under our commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels, our credit quality and the credit quality of our counterparties.

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

At December 31, 2008, we had committed lines of credit totaling $5.2 billion, excluding commitments provided by Lehman. These lines of credit support commercial paper borrowings, bank loans and letter of credit issuances. Our financial policy precludes issuing commercial paper in excess of our supporting lines of credit. At December 31, 2008, we had the following commercial paper, bank loans and letters of credit outstanding, as well as capacity available under credit facilities:

(millions)	Facility Limit	Outstanding Commercial Paper	Outstanding Bank Loans	Outstanding Letters of Credit	Facility Capacity Available
Five-year joint revolving credit facility(1)	**$2,837**	**$297**	**$ —**	**$187**	**$2,353**
Five-year Dominion credit facility(2)	**1,700**	**208**	**1,470**	**22**	**—**
Five-year Dominion bilateral facility(3)	**200**	**55**	**—**	**75**	**70**
364-day Dominion credit facility(4)	**467**	**—**	**—**	**—**	**467**
Totals	**$5,204**	**$560**	**$1,470**	**$284**	**$2,890**

(1) The $2.8 billion five-year credit facility was entered into February 2006 and terminates in February 2011. This credit facility can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion of letters of credit.

(2) The $1.7 billion five-year credit facility was entered into in August 2005 and terminates in August 2010. This facility can be used to support bank borrowings, the issuance of letters of credit and commercial paper.

(3) The $200 million five-year facility was entered into in December 2005 and terminates in December 2010. This credit facility can be used to support commercial paper and letter of credit issuances.

(4) The $467 million 364-day credit facility was entered into in July 2008 and terminates in July 2009. This credit facility can be used to support bank borrowings and the issuance of commercial paper.

In addition to the facilities above, we also entered into a $100 million bilateral credit facility in August 2004 that was to terminate in August 2009. In May 2008, we terminated this facility.

Also, in addition to the credit facility commitments of $5.2 billion disclosed above, we have a $182 million five-year credit facility, excluding commitments provided by Lehman, that supports certain Virginia Power tax-exempt financings.

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.

As previously discussed, we have entered into an agreement with BBIFNA to sell Peoples and Hope for approximately $910 million, subject to adjustments to reflect levels of capital expenditures and changes in working capital. The transaction is expected to close in 2009, subject to regulatory approvals in Pennsylvania and West Virginia as well as clearance under the Exon-Florio provision of the

Omnibus Trade and Competitiveness Act. We expect to use the after-tax proceeds from the sale to reduce our debt.

Long-Term Debt

During 2008 we issued the following long-term debt:

Type	Principal	Rate	Maturity	Issuing Company
	(millions)			
Senior notes	**$ 500**	**6.40%**	**2018**	**Dominion**
Senior notes	**400**	**7.00%**	**2038**	**Dominion**
Senior notes	**600**	**8.875%**	**2019**	**Dominion**
Senior notes	**300**	**Variable**	**2010**	**Dominion**
Senior notes	**600**	**5.40%**	**2018**	**Virginia Power**
Senior notes	**700**	**8.875%**	**2038**	**Virginia Power**
Total senior notes issued	**$3,100**			

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

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

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

Including the amounts discussed above, during 2008, we repaid $2.3 billion of long-term debt and notes payable, which also includes Virginia Power's repayment of the $412 million 7.375% unsecured Junior Subordinated Notes and the related redemption of all 16 million units of the $400 million 7.375% Virginia Power Capital Trust II preferred securities due July 30, 2042. These securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions.

Issuance of Common Stock

During 2008, we received proceeds of $240 million for 6.2 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. We expect to issue approximately $500 million of common stock in 2009 and $400 million in 2010. A portion of the proceeds will come from Dominion Direct®, employee savings plans and the exercise of employee stock options, with the remainder coming from issuances on the open market. In January 2009, we entered into three separate sales agency agreements with BNY Mellon Capital Markets, LLC; Merrill Lynch, Pierce, Fenner & Smith Incorporated; and Morgan Stanley & Co. Incorporated (collectively the Sales Agents) pursuant to which we may offer from time to time up to $400 million aggregate amount of our common stock. Sales of common stock can be made by means of privately negotiated transactions, as transactions on the New York Stock Exchange at market prices or in such other transactions as are agreed upon by the Company and the Sales Agents and in conformance with applicable securities laws. We provided sales instructions to one of the Sales Agents during February 2009 and have completed several trades resulting in the issuance of a moderate number of shares.

In February 2009, we also issued approximately 1.6 million shares of common stock to an existing holder of our senior notes, in a privately negotiated transaction, in exchange for approximately $56 million of the principal of two series of our outstanding senior notes, which were retired. The transaction was exempt from registration pursuant to Section 3(a)(9) of the Securities Act and no commission or remuneration was paid in connection with the exchange.

Repurchases of Common Stock

At December 31, 2008, the remaining stock repurchase authorization provided by our Board of Directors is the lesser of 54 million shares or $2.7 billion of our outstanding common stock. Dominion does not expect to repurchase its common stock during 2009, except for shares tendered by employees to satisfy tax withholding obligations on vesting restricted stock, which do not count against our stock repurchase authorization.

Credit Ratings

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. We believe that the current credit ratings of Dominion and Virginia Power (the Dominion Companies) provide sufficient access to the capital markets. However, disruptions in the banking and capital markets not specifically related to us may affect the Dominion Companies' ability to access these funding sources or cause an increase in the return required by investors.

Both quantitative (financial strength) and qualitative (business or operating characteristics) factors are considered by the credit rating agencies in establishing an individual company's credit rating. Credit ratings should be evaluated independently and are subject to revision or withdrawal at any time by the assigning rating organization. The credit ratings for the Dominion Companies are most affected by each company's financial profile, mix of regulated and nonregulated businesses and respective cash flows, changes in methodologies used by the rating agencies and "event risk," if applicable, such as major acquisitions or dispositions.

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

Credit ratings for the Dominion Companies as of February 1, 2009 follow:

	Fitch	Moody's	Standard & Poor's
Dominion Resources, Inc.			
Senior unsecured debt securities	**BBB+**	**Baa2**	**A–**
Junior subordinated debt securities	**BBB**	**Baa3**	**BBB**
Enhanced junior subordinated notes	**BBB**	**Baa3**	**BBB**
Commercial paper	**F2**	**P-2**	**A-2**
Virginia Power			
Mortgage bonds	**A**	**A3**	**A**
Senior unsecured (including tax-exempt) debt securities	**A–**	**Baa1**	**A–**
Junior subordinated debt securities	**BBB+**	**Baa2**	**BBB**
Preferred stock	**BBB+**	**Baa3**	**BBB**
Commercial paper	**F2**	**P-2**	**A-2**

As of February 1, 2009, Fitch, Moody's and Standard & Poor's maintain a stable outlook for their respective ratings of 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 all or substantially all of our assets;
- Compliance with collateral minimums or requirements related to mortgage bonds; and
- Limitations on liens.

We are required to pay minimal annual commitment fees to maintain our credit facilities. In addition, our credit agreements contain various terms and conditions that could affect our ability to borrow under these facilities. They include maximum debt to total capital ratios and cross-default provisions.

As of December 31, 2008, the calculated total debt to total capital ratio for our companies, pursuant to the terms of the agreements, was as follows:

Company	Maximum Ratio	Actual Ratio[1]
Dominion Resources, Inc.	**65%**	**60%**
Virginia Power	**65%**	**51%**

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

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

In June 2006 and September 2006, we executed Replacement Capital Covenants (RCCs) in connection with our offering of $300 million of 2006 Series A Enhanced Junior Subordinated Notes due 2066 (June hybrids) and $500 million of 2006 Series B Enhanced Junior Subordinated Notes due 2066 (September hybrids), respectively. Under the terms of the RCCs, we agree not to redeem or repurchase all or part of the June or September hybrids prior to June 30 or September 30, 2036, respectively, unless we issue qualifying securities to non-affiliates in a replacement offering in the 180 days prior to the redemption or repurchase date. The proceeds we receive from the replacement offering, adjusted by a predetermined factor, must exceed the redemption or repurchase price. Qualifying securities include common stock, preferred stock and other securities that generally rank equal to or junior to the hybrids and include distribution deferral and long-dated maturity features similar to the hybrids. For purposes of the RCCs, non-affiliates include individuals enrolled in our dividend reinvestment plan, direct stock purchase plan and employee benefit plans.

The September hybrids are designated as covered debt under the June hybrids' RCC and the June hybrids are designated as covered debt under the September hybrids' RCC.

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

Dividend Restrictions

The Virginia Commission may prohibit any public service company, including Virginia Power, from declaring or paying a dividend to an affiliate, if found to be detrimental to the public interest. At December 31, 2008, 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, 2008.

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

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

Contractual Obligations

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

	2009	2010 - 2011	2012 - 2013	2014 and thereafter	Total
(millions)					
Long-term debt(1)	**$ 435**	**$1,632**	**$2,234**	**$11,121**	**$15,422**
Interest payments(2)	**898**	**1,700**	**1,527**	**10,980**	**15,105**
Leases	**121**	**211**	**165**	**138**	**635**
Purchase obligations(3):					
Purchased electric capacity for utility operations	**361**	**699**	**710**	**1,499**	**3,269**
Fuel commitments for utility operations	**882**	**1,056**	**471**	**536**	**2,945**
Fuel commitments for nonregulated operations	**96**	**132**	**154**	**233**	**615**
Pipeline transportation and storage	**161**	**199**	**85**	**69**	**514**
Energy commodity purchases for resale(4)	**560**	**56**	**26**	**—**	**642**
Other(5)	**258**	**123**	**7**	**4**	**392**
Other long-term liabilities(6):					
Financial derivative-commodities(4)	**179**	**10**	**—**	**—**	**189**
Other contractual obligations(7)	**16**	**—**	**—**	**—**	**16**
Total cash payments	**$3,967**	**$5,818**	**$5,379**	**$24,580**	**$39,744**

(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 or interest payments on enhanced junior subordinated notes.

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

(4) Represents the summation of settlement amounts, by contracts, due from us if all physical or financial transactions among our counterparties and the Company were liquidated and terminated.

(5) Includes capital and operations and maintenance commitments.

(6) Excludes regulatory liabilities, AROs and employee benefit plan obligations, which are not contractually fixed as to timing and amount. See Notes 14, 15 and 22 to the Consolidated Financial Statements. Due to uncertainty about the timing and amounts that will ultimately be paid, $244 million of income taxes payable associated with unrecognized tax benefits are excluded. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete fiscal year. See Note 7 to our Consolidated Financial Statements.

(7) Includes interest rate swap agreements.

Planned Capital Expenditures

Our planned capital expenditures are expected to total approximately $4.0 billion, $3.6 billion and $3.8 billion in 2009, 2010 and 2011, respectively. These expenditures are expected to include construction and expansion of electric generation and natural gas transmission and storage facilities, environmental upgrades, construction improvements and expansion of 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. Our planned capital expenditures include capital projects that are subject to approval by regulators and our Board of Directors.

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

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

Use of Off-Balance Sheet Arrangements

Guarantees

We primarily enter into guarantee arrangements on behalf of our consolidated subsidiaries. These arrangements are not subject to the recognition and measurement provisions of FIN 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.*

At December 31, 2008, we had issued $419 million of guarantees to support third parties and equity method investees, primarily reflecting guarantees issued to support the NedPower and Fowler Ridge wind farm joint ventures. See Note 23 to our Consolidated Financial Statements for further discussion of these guarantees.

Leasing Arrangement

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

Benefits of this arrangement include:

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

Future Issues and Other Matters

See Item 1. Business, Item 3. Legal Proceedings and Note 23 to our Consolidated Financial Statements for additional information on various environmental, regulatory, legal and other matters that may impact our future results of operations and/or financial condition.

Environmental Matters

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

Environmental Protection and Monitoring Expenditures

We incurred approximately $205 million, $181 million and $138 million of expenses (including depreciation) during 2008, 2007 and 2006, respectively, in connection with environmental protection and monitoring activities and expect these expenses to be approximately $283 million and $297 million in 2009 and 2010, respectively. In addition, capital expenditures related to environmental controls were $254 million, $293 million and $332 million for 2008, 2007 and 2006, respectively. These expenditures are expected to be approximately $280 million and $375 million for 2009 and 2010, respectively.

Future Environmental Regulations

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

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. MD&A. The reader's attention is directed to those paragraphs and Item 1A. Risk Factors for discussion of various risks and uncertainties that may impact the Company.

Market Risk Sensitive Instruments and Risk Management

Our financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates and equity security prices as described below. Commodity price risk is present in our electric operations, gas production and procurement operations, and energy marketing and trading operations due to the exposure to market shifts in prices received and paid for electricity, natural gas and other commodities. We use commodity derivative contracts to manage price risk exposures for these operations. Interest rate risk is generally related to our outstanding debt. In addition, we are exposed to investment price risk through various portfolios of equity and debt securities.

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

Commodity Price Risk

To manage price risk, we primarily hold commodity-based financial derivative instruments held for non-trading purposes associated with purchases and sales of electricity, natural gas and other energy-related products. As part of our strategy to market energy and to manage related risks, we also hold commodity-based financial derivative instruments for trading purposes.

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

A hypothetical 10% unfavorable change in market prices of our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $236 million and $338 million as of December 31, 2008 and 2007, respectively. The decline is primarily due to decreases in gas and electricity prices. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $5 million and $8 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of December 31, 2008 and 2007, respectively.

The impact of a change in energy commodity prices on our non-trading commodity-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when such contracts are ultimately settled. Net losses from commodity derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction, such as revenue from physical sales of the commodity.

Interest Rate Risk

We manage our interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. We also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For financial instruments outstanding at December 31, 2008 and 2007, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $4 million and $11 million, respectively. The decline is due primarily to a decrease in variable rate debt.

Investment Price Risk

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

Following the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations in April 2007, gains or losses on those decommissioning trust investments are deferred as regulatory liabilities.

We recognized net realized losses (net of investment income) on nuclear decommissioning trust investments of $192 million in 2008 and net realized gains (including investment income) of $43 million in 2007. Net realized gains and losses include gains and losses from the sale of investments as well as any other-than-temporary declines in fair value. In 2008, we recorded, in AOCI and regulatory liabilities, a reduction in unrealized gains on these investments of $451 million. In 2007, we recorded, in AOCI and regulatory liabilities, an increase in unrealized gains on these investments of $52 million.

We sponsor employee pension and other postretirement benefit plans, in which our employees participate, that hold investments in trusts to fund benefit payments. Aggregate actual returns for our pension and other postretirement benefit plan assets were negative $1.4 billion in 2008 and positive $520 million in 2007, versus expected returns of $484 million and $462 million, respectively. Differences between actual and expected returns on plan assets are accumulated and amortized during future periods. As such, investment-related declines in these trusts, such as those experienced during 2008, will result in future increases in the periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash to be contributed to the employee benefit plans. As of December 31, 2008 and 2007, a hypothetical 0.25% decrease in the assumed long-term rates of return on our plan assets would result in an increase in net periodic cost of approximately $12 million for pension benefits and $2 million for other postretirement benefits.

Risk Management Policies

We have established operating procedures with corporate management to ensure that proper internal controls are maintained. In addition, we have established an independent function at the corporate level to monitor compliance with the risk management policies of all subsidiaries. We maintain credit policies that include the evaluation of a prospective counterparty's financial condition, collateral requirements where deemed necessary and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, we also monitor the financial condition of existing counterparties on an ongoing basis. Based on our credit policies and our December 31, 2008 provision for credit losses, management believes that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Dominion Resources, Inc.
Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Dominion Resources, Inc. and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, common shareholders' equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, the Company changed its methods of accounting to adopt new accounting standards for fair value measurements in 2008, uncertain tax positions in 2007, and pension and other postretirement benefit plans, share-based payments, and purchases and sales of inventory with the same counterparty in 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 24, 2009

Consolidated Statements of Income

Year Ended December 31,	2008	2007(1)	2006(1)
(millions, except per share amounts)			
Operating Revenue	**$16,290**	$14,816	$17,276
Operating Expenses			
Electric fuel and energy purchases	**3,963**	3,371	3,095
Purchased electric capacity	**411**	439	481
Purchased gas	**3,398**	2,775	3,569
Other energy-related commodity purchases	**60**	252	1,022
Other operations and maintenance	**3,257**	4,125	3,606
Gain on sale of U.S. non-Appalachian E&P business	**42**	(3,635)	—
Depreciation, depletion and amortization	**1,034**	1,368	1,557
Other taxes	**499**	552	568
Total operating expenses	**12,664**	9,247	13,898
Income from operations	**3,626**	5,569	3,378
Other income (loss)	**(58)**	102	173
Interest and related charges:			
Interest expense(2)	**749**	1,034	888
Interest expense—junior subordinated notes payable(3)	**87**	127	184
Subsidiary preferred dividends	**17**	16	16
Total interest and related charges	**853**	1,177	1,088
Income from continuing operations before income taxes, minority interest and extraordinary item	**2,715**	4,494	2,463
Income tax expense	**879**	1,783	927
Minority interest	**—**	6	6
Income from continuing operations before extraordinary item	**1,836**	2,705	1,530
Loss from discontinued operations(4)	**(2)**	(8)	(150)
Extraordinary item(5)	**—**	(158)	—
Net Income	**$ 1,834**	$ 2,539	$ 1,380
Earnings Per Common Share—Basic:			
Income from continuing operations before extraordinary item	**$ 3.17**	$ 4.15	$ 2.19
Loss from discontinued operations	**—**	(0.01)	(0.22)
Extraordinary item	**—**	(0.24)	—
Net income	**$ 3.17**	$ 3.90	$ 1.97
Earnings Per Common Share—Diluted:			
Income from continuing operations before extraordinary item	**$ 3.16**	$ 4.13	$ 2.17
Loss from discontinued operations	**—**	(0.01)	(0.21)
Extraordinary item	**—**	(0.24)	—
Net income	**$ 3.16**	$ 3.88	$ 1.96
Dividends paid per common share	**$ 1.58**	$ 1.46	$ 1.38

(1) Our 2007 and 2006 Consolidated Statements of Income have been recast to reflect our revised derivative income statement classification policy described in Note 2 of our Consolidated Financial Statements.
(2) In 2007, we incurred $242 million of expenses associated with the completion of a debt tender offer, $234 million of which is included in interest expense.
(3) Includes $33 million, $73 million and $104 million incurred with affiliated trusts in 2008, 2007 and 2006, respectively.
(4) Net of income tax expense (benefit) of ($3) million, $115 million and ($107) million in 2008, 2007 and 2006, respectively. The 2007 expense includes $76 million and $56 million for U.S. federal and Canadian taxes, respectively, related to the gain on the sale of the Canadian E&P operations.
(5) Reflects a $259 million ($158 million after-tax) extraordinary charge in connection with the reapplication of SFAS No. 71, Accounting for Certain Types of Regulation, to the Virginia jurisdiction of our generation operations.

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

Consolidated Balance Sheets

At December 31,	2008	2007
(millions)		
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 66**	$ 283
Customer receivables (less allowance for doubtful accounts of $32 and $37)	**2,354**	2,130
Other receivables (less allowance for doubtful accounts of $7 and $10)	**205**	226
Inventories:		
Materials and supplies	**509**	427
Fossil fuel	**328**	341
Gas stored	**329**	277
Derivative assets	**1,497**	775
Assets held for sale	**1,416**	1,160
Prepayments	**163**	387
Other	**794**	664
Total current assets	**7,661**	6,670
Investments		
Nuclear decommissioning trust funds	**2,246**	2,888
Investment in equity method affiliates	**726**	331
Loans held for resale (less allowance for loan losses of $7 in 2007)	**—**	323
Other	**285**	338
Total investments	**3,257**	3,880
Property, Plant and Equipment		
Property, plant and equipment	**35,448**	33,331
Accumulated depreciation, depletion and amortization	**(12,174)**	(11,979)
Total property, plant and equipment, net	**23,274**	21,352
Deferred Charges and Other Assets		
Goodwill	**3,503**	3,496
Pension and other postretirement benefit assets	**514**	1,565
Intangible assets	**712**	598
Regulatory assets	**2,226**	957
Other	**906**	621
Total deferred charges and other assets	**7,861**	7,237
Total assets	**$ 42,053**	$ 39,139

At December 31, (millions)	**2008**	2007
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Securities due within one year	**$ 444**	$ 1,477
Short-term debt	**2,030**	1,757
Accounts payable	**1,499**	1,734
Accrued interest, payroll and taxes	**754**	934
Derivative liabilities	**1,100**	694
Liabilities held for sale	**570**	492
Margin deposit liabilities	**406**	82
Accrued dividends	**260**	—
Other	**731**	590
Total current liabilities	**7,794**	7,760
Long-Term Debt		
Long-term debt	**13,890**	11,759
Junior subordinated notes payable to:		
Affiliates	**268**	678
Other	**798**	798
Total long-term debt	**14,956**	13,235
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**4,137**	4,253
Asset retirement obligations	**1,802**	1,722
Pension and other postretirement benefit liabilities	**1,525**	633
Regulatory liabilities	**944**	1,223
Other	**561**	622
Total deferred credits and other liabilities	**8,969**	8,453
Total liabilities	**31,719**	29,448
Commitments and Contingencies (see Note 23)		
Minority Interest	**—**	28
Subsidiary Preferred Stock Not Subject To Mandatory Redemption	**257**	257
Common Shareholders' Equity		
Common stock—no par[1]	**5,994**	5,733
Other paid-in capital	**182**	175
Retained earnings	**4,170**	3,510
Accumulated other comprehensive loss	**(269)**	(12)
Total common shareholders' equity	**10,077**	9,406
Total liabilities and shareholders' equity	**$42,053**	$39,139

(1) 1 billion shares authorized; 583 million shares and 577 million shares outstanding at December 31, 2008 and 2007, respectively.

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

Consolidated Statements of Common Shareholders' Equity

(millions)	Common Stock Shares	Common Stock Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2005	695	$11,286	$125	$ 1,550	$(2,564)	$10,397
Net income				1,380		1,380
Adjustment to initially apply SFAS No. 158, net of $239 tax					(335)	(335)
Issuance of stock—employee and direct stock purchase plans	2	95				95
Stock awards and stock options exercised (net of change in unearned compensation)	3	79				79
Issuance of stock—equity-linked securities	9	330				330
Stock repurchase and retirement	(11)	(540)				(540)
Tax benefit from stock awards and stock options exercised			8			8
Dividends and other adjustments			(5)	(970)		(975)
Other comprehensive income, net of tax					2,474	2,474
Balance at December 31, 2006	698	$11,250	$128	$ 1,960	$ (425)	$12,913
Net income				2,539		2,539
Stock awards and stock options exercised (net of change in unearned compensation)	8	251				251
Stock repurchase and retirement	(129)	(5,768)				(5,768)
Tax benefit from stock awards and stock options exercised			46			46
Adoption of FIN 48				(58)		(58)
Dividends and other adjustments			1	(931)		(930)
Other comprehensive income, net of tax					413	413
Balance at December 31, 2007	577	$ 5,733	$175	$ 3,510	$ (12)	$ 9,406
Net income				**1,834**		**1,834**
Issuance of stock—employee and direct stock purchase plans	**4**	**196**				**196**
Stock awards and stock options exercised (net of change in unearned compensation)	**2**	**65**				**65**
Tax benefit from stock awards and stock options exercised			**7**			**7**
Adoption of SFAS No. 157				**1**		**1**
Adoption of EITF 06-4				**(3)**		**(3)**
Dividends				**(1,172)**[1]		**(1,172)**
Other comprehensive loss, net of tax					**(257)**	**(257)**
Balance at December 31, 2008	**583**	**$ 5,994**	**$182**	**$ 4,170**	**$ (269)**	**$10,077**

(1) Includes $256 million of accrued dividends due to the early declaration of our first quarter 2009 common dividend in December 2008.

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income

Year Ended December 31,	**2008**	2007	2006
(millions)			
Net income	**$1,834**	$2,539	$1,380
Other comprehensive income (loss), net of taxes:			
Net deferred gains (losses) on derivatives—hedging activities, net of $(308), $140 and $(625) tax	**497**	(223)	1,173
Changes in unrealized gains on investment securities, net of $175, $75 and $(83) tax	**(264)**	(110)	126
Minimum pension liability adjustment, net of $(7) tax in 2006	**—**	—	10
Changes in net unrecognized pension and other postretirement benefit costs, net of $421 and $(80) tax in 2008 and 2007, respectively	**(662)**	164	—
Foreign currency translation adjustments	**—**	—	(8)
Amounts reclassified to net income:			
Net derivative losses—hedging activities, net of $(33), $(376) and $(724) tax	**52**	603	1,182
Realized (gains) losses on investment securities, net of $(77), $(4) and $6 tax	**111**	8	(9)
Net pension and other post retirement benefit costs, net of $(8) and $(10) tax in 2008 and 2007, respectively	**9**	21	—
Recognition of foreign currency translation gains upon sale of subsidiary	**—**	(50)	—
Total other comprehensive income (loss)	**(257)**	413	2,474
Comprehensive income	**$1,577**	$2,952	$3,854

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Year Ended December 31,	**2008**	2007	2006
(millions)			
Operating Activities			
Net income	**$ 1,834**	$ 2,539	$ 1,380
Adjustments to reconcile net income to net cash from operating activities:			
DCI impairment losses	**62**	88	89
Impairment of merchant generation assets	**—**	387	253
Costs associated with early retirement of debt	**—**	242	—
Gain on sale of non-Appalachian E&P business	**42**	(3,826)	—
Extraordinary item, net of income taxes	**—**	158	—
Charges related to termination of VPP agreements	**—**	139	—
Charges (benefits) related to planned sale of gas distribution subsidiaries	**(47)**	—	188
Net change in realized and unrealized derivative (gains) losses	**169**	(245)	(242)
Depreciation, depletion and amortization	**1,191**	1,533	1,739
Deferred income taxes and investment tax credits, net	**269**	(1,285)	510
Other adjustments	**116**	3	(105)
Changes in:			
Accounts receivable	**(222)**	294	684
Inventories	**(116)**	52	3
Prepayments	**222**	(142)	(37)
Deferred fuel and purchased gas costs, net	**(532)**	(349)	239
Accounts payable	**(268)**	(190)	(526)
Accrued interest, payroll and taxes	**(177)**	159	92
Margin deposit assets and liabilities	**210**	63	(7)
Other operating assets and liabilities	**(94)**	134	(255)
Net cash provided by (used in) operating activities	**2,659**	(246)	4,005
Investing Activities			
Plant construction and other property additions	**(3,315)**	(2,177)	(1,995)
Additions to gas and oil properties, including acquisitions	**(239)**	(1,795)	(2,057)
Proceeds from assignment of natural gas drilling rights	**343**	—	—
Proceeds from sales of gas and oil properties	**—**	12	393
Proceeds from sale of merchant generation peaking facilities	**—**	339	—
Proceeds from sale of non-Appalachian E&P business	**(21)**	13,877	—
Proceeds from sales of securities and loan receivable collections and payoffs	**1,394**	1,285	1,110
Purchases of securities and loan receivable originations	**(1,355)**	(1,355)	(1,196)
Proceeds from sale of emissions allowances held for consumption	**47**	11	76
Investment in affiliates and partnerships	**(376)**	(72)	(11)
Other	**32**	67	186
Net cash provided by (used in) investing activities	**(3,490)**	10,192	(3,494)
Financing Activities			
Issuance (repayment) of short-term debt, net	**273**	(575)	713
Issuance of long-term debt	**3,290**	2,675	2,450
Repayment of long-term debt, including redemption premiums	**(1,842)**	(5,012)	(2,333)
Repayment of affiliated notes payable	**(412)**	(440)	(300)
Issuance of common stock	**240**	226	479
Repurchase of common stock	**—**	(5,768)	(540)
Common dividend payments	**(916)**	(931)	(970)
Other	**(18)**	24	(14)
Net cash provided by (used in) financing activities	**615**	(9,801)	(515)
Increase (decrease) in cash and cash equivalents	**(216)**	145	(4)
Cash and cash equivalents at beginning of year	**287**	142	146
Cash and cash equivalents at end of year[1]	**$ 71**	$ 287	$ 142
Supplemental Cash Flow Information:			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 858**	$ 1,021	$ 920
Income taxes	**413**	3,155	432
Significant noncash investing and financing activities:			
Accrued capital expenditures	**194**	58	258
Accrued common and preferred dividends	**260**	—	—

(1) 2008 amount includes $5 million and 2007 and 2006 amounts include $4 million of cash classified as held for sale in the Consolidated Balance Sheets.

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

Note 1. Nature of Operations

Dominion Resources, Inc. (Dominion), headquartered in Richmond, Virginia, is one of the nation's largest producers and transporters of energy.

Our principal subsidiaries are Virginia Power, DEI, DTI, VPEM, DEPI, Dominion East Ohio, DFS, Dominion Retail and DRS.

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

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

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

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

DEPI explores for, develops and produces natural gas and oil in the Appalachian basin of the U.S.

DFS is involved in the gathering and aggregation of Appalachian natural gas supply and provides various marketing-related services to its customers.

Dominion Retail markets gas, electricity and related products and services to residential and small commercial and industrial customers. As of December 31, 2008, these nonregulated retail energy marketing operations served approximately 1.6 million residential and small commercial and industrial customer accounts in the Northeast, mid-Atlantic and Midwest regions of the U.S and Texas.

As of December 31, 2008, our regulated gas distribution subsidiaries, Dominion East Ohio, Peoples and Hope, served approximately 1.7 million residential, commercial and industrial gas sales and transportation customer accounts in Ohio, Pennsylvania and West Virginia. Of these customers, approximately 500,000 are served by Peoples and Hope, which are held for sale as discussed in Note 5. We also operate a LNG import and storage facility in Maryland.

DRS provides accounting, legal, finance and certain administrative and technical services to our subsidiaries. In addition, all of our officers are employees of DRS.

We manage our daily operations through three primary operating segments: DVP, Dominion Energy and Dominion Generation. In addition, we also report a Corporate and Other segment that includes our corporate, service company and other functions and the net impact of certain operations disposed of or to be disposed of, which are discussed in Note 5. Corporate and Other also includes specific items attributable to Dominion's operating segments that are not included in profit measures evaluated by executive management, in assessing the segments' performance or allocating resources among the segments. Our assets remain wholly owned by us and our legal subsidiaries.

The terms "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 or more 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 GAAP. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the periods presented. Actual results may differ from those estimates.

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

In accordance with GAAP, we report certain contracts and instruments at fair value. See Note 8 for further information on fair value measurements in accordance with SFAS No. 157.

Certain amounts in our 2007 and 2006 Consolidated Financial Statements and footnotes have been recast to conform to the 2008 presentation. See Note 3 for discussion of the recast of our 2007 Consolidated Balance Sheet due to the adoption of FSP FIN 39-1, *Amendment of FIN 39, Offsetting of Amounts Related to Certain Contracts*. Additionally, in the fourth quarter of 2008, we revised our derivative income statement classification policy, described in *Derivative Instruments*, to present income statement activity for all non-trading derivatives based on the nature of the underlying risk. This includes unrealized changes in the fair value of and settlements of financially-settled derivatives not held for trading purposes, as well as gains or losses attributable to ineffectiveness, changes in the time value of options, and discontinuances of hedging instruments, which were previously presented in other operations and maintenance expense on a net basis. Our prior year Consolidated Statements of Income have been recast to conform to the 2008 presentation, however this had no impact on earnings.

Reapplication of SFAS No. 71

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

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

EXTRAORDINARY ITEM

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

PENSION AND OTHER POSTRETIREMENT BENEFITS

Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, we reclassified $110 million ($67 million after tax) of pension and other postretirement benefit costs attributable to those operations previously recorded in AOCI to a regulatory asset. These costs represent net unrecognized actuarial (gains) losses, unrecognized prior service cost (credit) and unrecognized transition obligation remaining from our initial adoption of SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, that will be recognized as a component of future net periodic benefit cost and are expected to be recovered through future rates.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. Our customer receivables at December 31, 2008 and 2007 included $401 million and $305 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity 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 are as follows:

- **Regulated electric sales** consist primarily of state-regulated retail electric sales, and federally-regulated wholesale electric sales and electric transmission services;
- **Nonregulated electric sales** consist primarily of sales of electricity at market-based rates and contracted fixed rates, electric trading revenue and associated derivative activity;
- **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 production at market-based rates and contracted fixed prices, sales of gas purchased from third parties, gas trading and marketing revenue, sales activity related to agreements used to facilitate the marketing of gas production and gas transportation (buy/sell arrangements) described in Note 3 and associated derivative activity. Revenue from sales of gas production is recognized based on actual volumes of gas sold to purchasers and is reported net of royalties. Sales require delivery of the product to the purchaser, passage of title and probability of collection of purchaser amounts owed. Revenue from sales of gas production includes the sale of Company produced gas and the recognition of revenue previously deferred in connection with the VPP transactions described in Note 12. We use the sales method of accounting for gas imbalances related to gas production. An imbalance is created when Company volumes of gas sold pertaining to a property do not equate to the volumes to which we are entitled based on our interest in the property. A liability is recognized when our excess sales over entitled volumes exceeds our net remaining property reserves;
- **Other energy-related commodity sales** consist primarily of sales of oil and NGL production and condensate, coal, emissions allowances held for resale, extracted products and sales activity related to agreements used to facilitate the marketing of oil production (buy/sell arrangements) described in Note 3 and associated derivative activity;
- **Gas transportation and storage** consists primarily of regulated sales of gathering, transmission, distribution and storage services and associated derivative activity. Also included are regulated gas distribution charges to retail distribution service customers opting for alternate suppliers; and
- **Other revenue** consists primarily of miscellaneous service revenue from electric and gas distribution operations, gas processing and handling revenue, revenues from DCI operations and business interruption insurance revenue associated with delayed gas and oil production caused by hurricanes.

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 related levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. The deferral of costs in excess of current period fuel rate recovery is recognized as a regulatory asset, while rate recovery in excess of current period fuel expenses is recognized as a regulatory liability.

For electric fuel and purchased energy expenses, effective January 1, 2004, the fuel factor provisions for our Virginia retail customers were fixed until July 1, 2007. Effective July 1, 2007 and 2008, the fuel factor was adjusted as discussed under *Virginia Fuel Expenses* in Note 23. Of the cost of fuel used in electric generation and energy purchases to serve utility customers, approximately 82% is currently subject to deferred fuel accounting, while substantially all of the remaining amount is subject to recovery through similar mechanisms.

Income Taxes

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

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

Effective January 1, 2007, we adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*. In our financial statements, we recognize positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information.

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

Prior to the adoption of FIN 48, we established liabilities for tax-related contingencies when the incurrence of the liability was determined to be probable and the amount could be reasonably estimated in accordance with SFAS No. 5, *Accounting for Contingencies*, and subsequently reviewed them in light of changing facts and circumstances.

We recognize changes in estimated interest payable on net underpayments and overpayments of income taxes in interest expense and estimated penalties that may result from the settlement of some uncertain tax positions in other income. In our Consolidated Statements of Income for 2008, 2007 and 2006, we recognized less than $1 million of interest expense and no penalties, a reduction in interest expense of $19 million and no penalties and $2 million of interest expense and no penalties, respectively. We had accrued interest receivable of $2 million and interest and penalties payable of $5 million at December 31, 2008. At December 31, 2007, we had accrued $9 million for the payment of interest and penalties.

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

Stock-based Compensation

We measure and recognize compensation expense in accordance with SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 123R), which requires that compensation expense relating to share-based payment transactions be recognized in the financial statements based on the fair value of the equity or liability instruments issued. We adopted SFAS No. 123R using the modified prospective application transition method. Under this transition method, compensation cost is 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, *Accounting for Stock-Based Compensation*, for all awards granted prior to January 1, 2006, but not vested as of that date.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. At December 31, 2008 and 2007, accounts payable included $60 million and $93 million, respectively, of checks outstanding but not yet presented for payment. For purposes of our Consolidated Statements of Cash Flows, we consider cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

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 $8 million at December 31, 2008 and 2007. Based on the average price of gas purchased during 2008, the cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by approximately $208 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 physical 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 at period end, subject to the terms of our tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due to us from other parties are reported in other current assets and imbalances that we owe to other parties are reported in other current liabilities in our Consolidated Balance Sheets.

Derivative Instruments

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

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

To manage price risk, we hold certain derivative instruments, that are not 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 our exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. As part of our strategy to market energy and manage related risks, we also manage a portfolio of commodity-based financial derivative instruments held for trading purposes. We use established policies and procedures to manage the risks associated with price fluctuations in these energy commodities and use various derivative instruments to reduce risk by creating offsetting market positions.

Statement of Income Presentation:

- **Derivatives Held for Trading Purposes:** All income statement activity, including amounts realized upon settlement, is presented in operating revenue on a net basis.
- **Derivatives Not Held for Trading Purposes:** All income statement activity, including amounts realized upon settlement, is presented in operating revenue, operating expense or interest and related charges based on the nature of the underlying risk. As previously discussed, under our former derivative income statement classification policy, this activity was presented in other operations and maintenance expense on a net basis. Following the revision of this policy in the fourth quarter of 2008, our prior year Consolidated Statements of Income were recast to conform to the 2008 presentation.

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

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

Derivative Instruments Designated as Hedging Instruments

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

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

Cash Flow Hedges—A 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 other energy-related products. We also use foreign currency forward and option contracts to hedge the variability in foreign exchange rates and interest rate swaps to hedge our exposure to variable interest rates on long-term debt. For transactions in which we are hedging the variability of cash flows, changes in the fair value of the derivative are reported in AOCI, to the extent they are effective at offsetting changes in the hedged item. We reclassify any derivative gains or losses reported in AOCI to earnings when the forecasted item is included in earnings, or earlier, if it becomes probable that the forecasted transaction will not occur. For cash flow hedge transactions, we discontinue hedge accounting if the occurrence of the forecasted transaction is no longer probable.

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

See Note 8 for further information about fair value measurements and associated valuation methods for derivatives under SFAS No. 157.

Investments

Marketable Equity and Debt Securities

We account for and classify investments in marketable equity and debt securities in two categories:

- *Trading securities* include marketable equity and debt securities held in rabbi trusts associated with certain deferred compensation plans. These securities are reported in other investments in our Consolidated Balance Sheets at fair value with net realized and unrealized gains and losses included in other income in our Consolidated Statements of Income.
- *Available-for-sale securities* include all other marketable equity and debt securities, primarily comprised of securities held in the nuclear decommissioning trusts. These investments are reported at fair value in nuclear decommissioning trust funds and other investments in our Consolidated Balance Sheets. Upon reapplication of SFAS No. 71 in April 2007 for our utility generation operations, net realized and unrealized gains and losses (including any other-than-temporary impairments) on investments held in our utility nuclear decommissioning trusts are recorded to a regulatory liability for certain jurisdictions subject to cost-based regulation. For all other available-for-sale securities, including those held in our merchant generation nuclear decommissioning trusts, net realized gains and losses (including any other-than-temporary impairments) are included in other income and unrealized gains are reported as a component of AOCI, net of tax.

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

Non-Marketable Investments

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

- *Equity method investments* when we have the ability to exercise significant influence, but not control, over the investee. These investments are recorded in investments in equity method affiliates in our Consolidated Balance Sheets. We record equity method adjustments in other income in our Consolidated Statements of Income including: our proportionate share of investee income or loss, gains or losses resulting from investee capital transactions, amortization of certain differences between our carrying value and our equity in the net assets of the investee at the date of investment and other adjustments required by the equity method.
- *Cost method investments* when we do not have the ability to exercise significant influence over the investee. These investments are included in other investments and nuclear decommissioning trust funds.

Other Than Temporary Impairment

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

Property, Plant and Equipment

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

In 2008, 2007 and 2006, we capitalized interest costs and AFUDC of $88 million, $102 million and $134 million to property, plant and equipment, respectively. Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations in April 2007, we discontinued capitalizing interest on utility generation-related construction projects since the Virginia Commission previously allowed for current recovery of construction financing costs. Under current Virginia legislation, certain Virginia jurisdictional projects qualify for current recovery of AFUDC through rate adjustment clauses. AFUDC on these projects is calculated and recorded as a regulatory asset prior to the implementation of the rate adjustment clause and is not capitalized to property, plant and equipment. In 2008 and 2007, we recorded $18 million and $1 million of AFUDC related to these projects, respectively.

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

For property that is not subject to cost-of-service rate regulation, including nonutility property and utility generation property prior to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations in April 2007, cost of removal not associated with AROs is charged to expense as incurred. We also record gains and losses upon retirement based upon the difference between the proceeds received, if any, and the property's net book value at the retirement date.

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

Year Ended December 31,	**2008**	2007	2006
(percent)			
Generation [1]	**2.60**	2.24	2.07
Transmission	**2.22**	2.26	2.28
Distribution	**3.22**	3.21	3.28
Storage	**2.87**	2.78	3.10
Gas gathering and processing	**2.13**	2.09	2.05
General and other	**4.35**	4.92	5.22

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

Our nonutility property, plant and equipment, excluding E&P 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	**6–40 years**
General and other	**3–25 years**

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

We follow the full cost method of accounting for gas and oil E&P activities prescribed by the 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, discounted at 10%, 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. Approximately 4% 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, 2008. Future cash flows associated with settling AROs that have been accrued in our Consolidated Balance Sheets pursuant to SFAS No. 143, are excluded from our calculations under the full cost ceiling test. Decreases in commodity prices, as well as changes in production levels, reserve estimates, future development costs, and lifting costs and other factors could result in future ceiling test impairments.

Depletion of gas and oil producing properties is computed using the units-of-production method. Under the full cost method, the depletable base of costs subject to depletion 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 including associated exploration-related costs are initially excluded from the depletable base. Until the properties are evaluated, a ratable portion of the capitalized costs is periodically reclassified to the depletable 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 depletable 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. In 2007, we recognized gains from the sales of our Canadian and U.S. non-Appalachian E&P businesses. See Note 5 to our Consolidated Financial Statements for additional information.

Emissions Allowances

Emissions allowances permit the holder of the allowance to emit certain gaseous by-products of fossil fuel combustion, including SO_2, NO_x and CO_2. SO_2 and NO_x emissions allowances are issued by the EPA. CO_2 emissions allowances are purchased through quarterly auctions held by each participating RGGI state. The first RGGI auctions of CO_2 allowances were conducted in 2008 to be used for the compliance period beginning in 2009 and extending through 2011. Compliance with the RGGI requirements only applies to certain of our merchant power stations located in the Northeast.

Allowances held may be transacted with third parties or consumed as these emissions are generated. Allowances allocated to or acquired by our generation operations are held primarily for consumption. Allowances acquired by our energy marketing operations are held for the purpose of resale to third parties.

Allowances Held for Consumption

Allowances held for consumption are classified as intangible assets in our Consolidated Balance Sheets. Carrying amounts are based on our cost to acquire the allowances or, in the case of a business combination, on 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 the emissions are generated, with the amortization reflected in depreciation, depletion and amortization expense in our Consolidated Statements of Income. We report purchases and sales of these allowances as investing activities in our Consolidated Statements of Cash Flows and gains or losses resulting from sales in other operations and maintenance expense in our Consolidated Statements of Income.

Allowances Held for Resale

Allowances held for resale are classified as materials and supplies inventory in our Consolidated Balance Sheets and valued at the lower of cost of market (LOCOM).

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

Goodwill and Intangible Assets

We evaluate goodwill for impairment annually as of April 1 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. A long-lived or intangible asset is written down to fair value if the sum of its expected future undiscounted cash flows is less than its carrying amount.

Regulatory Assets and Liabilities

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

Asset Retirement Obligations

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

Amortization of Debt Issuance Costs

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

Note 3. Newly Adopted Accounting Standards

2008

SFAS No. 157

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

Generally, the provisions of this statement are applied prospectively. Certain situations, however, require retrospective application as of the beginning of the year of adoption through the recognition of a cumulative effect of accounting change. Such retrospective application was required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses under EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, and SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments*. Retrospective application resulted in an immaterial amount recognized through a cumulative effect of accounting change adjustment to retained earnings as of January 1, 2008.

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

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

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

See Note 8 for further information on fair value measurements in accordance with SFAS No. 157.

SFAS No. 159

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

FSP FIN 39-1

The provisions of FSP FIN 39-1 became effective for us beginning January 1, 2008. FSP FIN 39-1 amended FIN 39 to permit the offsetting of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. Upon our adoption of FSP FIN 39-1, we revised our accounting policy to no longer offset fair value amounts recognized for certain derivative instruments and recast our prior year Consolidated Balance Sheet in order to retrospectively apply the standard. The adoption of FSP FIN 39-1 resulted in an increase in Derivative assets of $14 million, Other deferred charges and other assets of $2 million, Derivative liabilities of $14 million and Other deferred credits and other liabilities of $2 million as of December 31, 2007. FSP FIN 39-1 also requires disclosures related to our cash collateral, for which we had recorded margin assets of $168 million and margin liabilities of $406 million at December 31, 2008. The adoption of FSP FIN 39-1 had no impact on our results of operations or cash flows.

FSP FAS 140-4 and FIN 46R-8

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

EITF 06-4

The provisions of EITF Issue No. 06-4, *Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements* became effective for us beginning January 1, 2008. EITF 06-4 specifies that if an employer provides a benefit to an employee under an endorsement split-dollar life insurance arrangement that extends to postretirement periods, it should recognize a liability for future benefits in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (if, in substance, a postretirement benefit plan exists) or APB Opinion No. 12, *Deferred Compensation Contracts* (if the arrangement is, in substance, an individual deferred compensation contract) based on the substantive agreement with the employee. The adoption of EITF 06-4 resulted in an immaterial amount recognized through a cumulative effect of accounting change adjustment to retained earnings as of January 1, 2008.

EITF 06-11

The provisions of EITF Issue No. 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards*, became effective for us beginning January 1, 2008. EITF 06-11 addresses the recognition of income tax benefits realized from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for nonvested share-based payment awards that are classified as equity. Effective January 1, 2008, we began recognizing such income tax benefits as an increase to additional paid-in capital rather than as a reduction to income tax expense. Our adoption of EITF 06-11 did not have a material impact on our results of operations or financial condition.

2007

FIN 48

We adopted the provisions of FIN 48, on January 1, 2007. As a result of the implementation of FIN 48, we recorded a $58 million charge to beginning retained earnings, representing the cumulative effect of the change in accounting principle. Our unrecognized tax benefits totaled $625 million as of January 1, 2007. For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility.

EITF 06-3

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

2006

SFAS No. 123R

Effective January 1, 2006, we adopted SFAS No. 123R which requires that compensation expense relating to share-based payment transactions be recognized in the financial statements based on the fair value of the equity or liability instruments issued. SFAS No. 123R covers a wide range of share plans, performance-based awards, share appreciation rights and employee share purchase plans. We adopted SFAS No. 123R using the modified prospective application transition method. Under this transition method, compensation cost is 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 that date. Accordingly, results for prior periods were not restated.

SFAS No. 158

Effective December 31, 2006, we adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans.* SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of its defined benefit pension and other postretirement benefit plans as an asset or liability, respectively, in its balance sheet and to recognize changes in the funded status as a component of other comprehensive income in the year in which the changes occur. The funded status is measured as the difference between the fair value of a plan's assets and the benefit obligation. In addition, SFAS No. 158 requires an employer to measure benefit plan assets and obligations that determine the funded status of a plan as of the end of the employer's fiscal year, which we already do.

Our adoption of SFAS No. 158 had no impact on our results of operations or cash flows and it will not affect our operating results or cash flows in future periods. Upon adoption, we recorded regulatory assets (liabilities), rather than an adjustment to AOCI, for previously unrecognized pension and other postretirement benefit costs (credits) expected to be recovered (refunded) through future rates by certain of our rate-regulated subsidiaries.

EITF 04-13

Prior to the sale of our non-Appalachian E&P business, we entered into buy/sell and related agreements primarily as a means to reposition our offshore Gulf of Mexico crude oil production to more liquid onshore marketing locations and to facilitate gas transportation. 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*, which requires 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. We adopted the provisions of EITF 04-13 on April 1, 2006 for new arrangements and modifications or renewals of existing arrangements made after that date. As a result, a significant portion of our activity related to buy/sell arrangements is presented on a net basis in our Consolidated Statements of Income for 2007 and 2006; however, there was no impact on our results of operations or cash flows. With the sale of the majority of our U.S. non-Appalachian E&P business in 2007, we no longer have any buy-sell arrangements that were entered into prior to April 2006. Pursuant to the transition provisions of EITF 04-13, activity related to buy/sell arrangements that were entered into prior to April 2006 and had not been modified or renewed after that date continued to be reported on a gross basis as follows:

Year Ended December 31,	2007	2006
(millions)		
Sale activity included in operating revenue	$67	$576
Purchase activity included in operating expenses(1)	72	578

(1) Included in other energy-related commodity purchases expense and purchased gas expense in our Consolidated Statements of Income.

Note 4. Recently Issued Accounting Standards

SFAS No. 141R

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations.* SFAS No. 141R requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS No. 141R also requires disclosure of information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS No. 141R requires that acquisition-related costs be expensed as incurred. The provisions of SFAS No. 141R became effective for acquisitions completed on or after January 1, 2009; however, the income tax provisions of SFAS No. 141R became effective as of that date for all acquisitions, regardless of the acquisition date. SFAS No. 141R amends SFAS No. 109 to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141R further amends SFAS No. 109 and FIN 48, to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties and acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances. For acquisitions completed on or before December 31, 2008, we do not expect these SFAS No. 141R provisions to have a material impact on our future results of operations or financial condition.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements.* SFAS No. 160 requires that:

- noncontrolling (minority) interests be reported as a component of equity;
- net income attributable to the parent and to the noncontrolling interest be separately identified in the income statement;
- changes in a parent's ownership interest while the parent retains its controlling interest be accounted for as equity transactions; and
- any retained non-controlling equity investment upon the deconsolidation of a subsidiary be initially measured at fair value.

The provisions of SFAS No. 160 became effective for us beginning January 1, 2009 and the disclosure provisions are to be applied retrospectively. We do not expect the provisions of SFAS No. 160 to have an impact on our results of operations or financial condition.

SFAS No. 161

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

FSP EITF 03-6-1

In June 2008, the FASB issued FSP EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.* This FSP addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method as described in SFAS No. 128, *Earnings per Share.* Under the guidance in FSP EITF 03-6-1, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method. The provisions of FSP EITF 03-6-1 became effective for us beginning January 1, 2009 and are to be applied retrospectively. We do not expect FSP EITF 03-6-1 to have a material impact on our earnings per share.

FSP APB 14-1

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement).* FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) are not addressed by paragraph 12 of Accounting Principles Board Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants.* The FSP specifies that issuers of convertible debt instruments should separately account for the liability and equity components in a manner that will reflect the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The provisions of FSP APB 14-1 became effective for us beginning January 1, 2009 and are to be applied retrospectively. We have determined that the provisions of FSP APB 14-1 are applicable to our 2.125% unsecured convertible senior notes due in 2023. See Note 18 for additional information on these convertible securities. We are currently evaluating the impact that FSP APB 14-1 will have on our results of operations and financial condition.

FSP FAS 132R-1

In December 2008, the FASB issued FSP FAS 132R-1, *Employers' Disclosures about Postretirement Benefit Plan Assets.* This FSP amends FASB Statement No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits,* to provide guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. FSP FAS 132R-1 requires companies to disclose how investment allocation decisions are made, including factors that are pertinent to an understanding of investment policies and strategies. The FSP also requires disclosure, separately for pension plans and other postretirement benefit plans, of the fair value of each major category of plan assets as of each annual reporting date for which a statement of financial position is presented with categories based on the nature and risks of assets in the employer's plans. Companies are also required to disclose information that enables users of financial statements to assess the inputs and valuation techniques used to develop fair value measurements of plan assets. For fair value measurements using significant unobservable inputs (Level 3), an employer must disclose the effect of the measurements on changes in plan assets for the period. Companies are also required to disclose any significant concentrations of risk in plan assets. The provisions of FSP FAS 132R-1 will become effective for disclosures in our Annual Report on Form 10-K for the year ended December 31, 2009.

SEC Final Rule, *Modernization of Oil and Gas Reporting*

In December 2008, the SEC released Final Rule, *Modernization of Oil and Gas Reporting,* to revise the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. In addition, the new disclosure requirements require a company to: (a) disclose its internal controls over reserves estimation and report the independence and qualifications of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The provisions of this final ruling will become effective for disclosures in our Annual Report on Form 10-K for the year ended December 31, 2009.

Note 5. Acquisitions and Dispositions

Acquisition of Pablo Energy LLC

In February 2006, we completed the acquisition of Pablo Energy LLC (Pablo) for approximately $92 million in cash. Pablo held producing and other properties located in the Texas Panhandle area. The operations of Pablo were formerly included in our Dominion E&P operating segment. The historical results of these operations are included in our Corporate and Other segment.

Sale of Non-Appalachian Natural Gas and Oil E&P Operations and Assets

In 2007, we completed the sale of our non-Appalachian natural gas and oil E&P operations and assets for approximately $13.9 billion. We received approximately $13.3 billion for our U.S. non-Appalachian E&P operations and approximately $624 million for our Canadian E&P operations.

Due to the sale of our entire Canadian cost pool, the results of operations for our Canadian E&P business are reported as discontinued operations in our Consolidated Statements of Income. The results of operations for our U.S. non-Appalachian E&P business were not reported as discontinued operations in our Consolidated Statements of Income since we did not sell our entire U.S. cost pool, which includes the retained Appalachian assets.

We used most of the after-tax proceeds from these dispositions to reduce our outstanding debt and repurchase shares of our common stock, as discussed in Notes 18 and 20.

The E&P operations we have sold are as follows:

Canadian Operations

The sale of our Canadian E&P operations resulted in an after-tax gain of $59 million ($0.08 per share).

The following table presents selected information regarding the results of operations of our Canadian E&P operations, which are reported as discontinued operations in our Consolidated Statements of Income:

Year Ended December 31,	2008	2007	2006
(millions)			
Operating revenue	$—	$ 67(1)	$145(1)
Income (loss) before income taxes	(5)(2)	145(3)	24

(1) Recast to reflect our revised derivative income statement classification policy as discussed in Note 2 to our Consolidated Financial Statements.
(2) Amount reflects the net effect of contractual post-closing adjustments to the sale.
(3) Amount includes pre-tax gain of $191 million recognized on the sale.

Costs Associated with Disposal of Non-Appalachian E&P Operations

The sales of our U.S. non-Appalachian E&P operations resulted in the discontinuance of hedge accounting for certain cash flow hedges since it became probable that the forecasted sales of gas and oil would not occur. In connection with the discontinuance of hedge accounting for these contracts, we recognized charges, recorded in operating revenue in our Consolidated Statement of Income, predominantly reflecting the reclassification of losses from AOCI to earnings and subsequent changes in fair value of these contracts of $541 million ($342 million after-tax) in 2007. We terminated these gas and oil derivatives subsequent to the disposal of the non-Appalachian E&P business. We recognized a similar charge of $15 million ($9 million after-tax) in 2007 related to our Canadian operations, which is reflected in discontinued operations in our Consolidated Statement of Income.

During 2007, we also recorded a charge in operating revenue in our Consolidated Statement of Income of approximately $171 million ($108 million after-tax) for the recognition of certain forward gas contracts that previously qualified for the normal purchase and sales exemption under SFAS No. 133. The $171 million charge included $139 million associated with VPP agreements to which we were a party. We paid $250 million to terminate the VPP agreements and have retained the repurchased fixed-term overriding royalty interests formerly associated with these agreements.

Additionally, we recognized expenses for employee severance, retention and other costs of $91 million ($56 million after-tax) in 2007, related to the sale of our U.S. non-Appalachian E&P business, which are reflected in other operations and maintenance expense in our Consolidated Statement of Income. We also recognized expenses for employee severance, retention, legal, investment banking and other costs of $30 million ($18 million after-tax) in 2007 related to the sale of our Canadian E&P operations, which are reflected in discontinued operations in our Consolidated Statement of Income.

We recognized a gain of approximately $3.6 billion ($2.1 billion after-tax) from the disposition of our U.S. non-Appalachian E&P operations. This gain is net of expenses related to the disposition plan for transaction costs, including audit, legal, investment banking and other costs of $48 million ($30 million after-tax), but excludes severance and retention costs and costs associated with the discontinuance of hedge accounting and recognition of forward gas contracts. In 2008, the net effect of contractual post-closing adjustments resulted in a $42 million ($26 million after-tax) reduction to the gain recognized in 2007. The total impact on net income from the sale of our Canadian and U.S. non-Appalachian E&P operations was a benefit of $1.5 billion for 2007. This benefit is net of expenses for transaction costs, severance and retention costs, costs associated with the discontinuance of hedge accounting and recognition of forward gas contracts, and costs associated with our debt tender offer completed in July 2007 using a portion of the proceeds received from the sale, as discussed in Note 18.

Disposition of Partially Completed Generation Facility

In September 2007, we completed the sale of Dresden to AEP Generating Company (AEP) for $85 million. During 2007, we recorded a $387 million ($252 million after-tax) impairment charge in other operations and maintenance expense to reduce Dresden's carrying amount to its estimated fair value based on AEP's purchase price.

Sale of Certain DCI Operations

In May 2007, we committed to a plan to dispose of certain DCI operations including substantially all of the assets of Gichner, all of the issued and outstanding shares of the capital stock of Gichner, Inc. (an affiliate of Gichner), as well as all of the membership interests in Dallastown.

The consideration to be received indicated that the goodwill associated with these operations was impaired and we recorded a goodwill impairment charge of $8 million in other operations and maintenance expense in our Consolidated Statement of Income. In August 2007, we completed the sale of Gichner and Dallastown for approximately $30 million. The sale resulted in an after-tax loss of $4 million, which included $10 million of goodwill.

The following table presents selected information regarding the results of operations of Gichner and Dallastown, which are reported as discontinued operations in our Consolidated Statements of Income:

Year Ended December 31,	2007	2006
(millions)		
Operating revenue	$29	$41
Income (loss) before income taxes	(7)	2

Sale of Merchant Generation Facilities

In 2007, we sold three Peaker facilities for net cash proceeds of $254 million. The sale resulted in a $24 million after-tax loss ($0.03 per share). The Peaker facilities included:

- Armstrong, a 625 Mw station in Shelocta, Pennsylvania;
- Troy, a 600 Mw station in Luckey, Ohio; and
- Pleasants, a 313 Mw station in St. Mary's, West Virginia.

During 2006, we recorded a $253 million ($164 million after-tax) impairment charge in other operations and maintenance expense to reduce the Peaker facilities' carrying amount to their estimated fair value less cost to sell.

The following table presents selected information regarding the results of operations of the Peaker facilities, which are reported as discontinued operations in our Consolidated Statements of Income:

Year Ended December 31,	2007	2006
(millions)		
Operating revenue	$ 5	$ 42
Loss before income taxes	(31)	(283)

The Peaker facilities' operating revenues were related to sales to other Dominion affiliates. In addition, the Peaker facilities purchased $1 million and $14 million of electric fuel from affiliates in 2007 and 2006, respectively.

Planned Sale of Regulated Gas Distribution Subsidiaries

On March 1, 2006, we entered into an agreement with Equitable, to sell two of our wholly-owned regulated gas distribution subsidiaries, Peoples and Hope. Peoples and Hope serve approximately 500,000 customer accounts in Pennsylvania and West Virginia. This sale was subject to regulatory approvals in the states in which the companies operate, as well as antitrust clearance under the HSR Act. In January 2008, Dominion and Equitable announced the termination of the agreement for the sale of Peoples and Hope, primarily due to the continued delay in achieving final regulatory approval. We continued to seek other offers for the purchase of these utilities.

In July 2008, we announced that we entered into an agreement with a subsidiary of BBIFNA to sell Peoples and Hope for approximately $910 million, subject to adjustments to reflect levels of capital expenditures and changes in working capital. The transaction is expected to close in 2009, subject to regulatory approvals in Pennsylvania and West Virginia as well as clearance under the Exon-Florio provision of the Omnibus Trade and Competitiveness Act.

The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheets are as follows:

As of December 31,	2008	2007
(millions)		
ASSETS		
Current Assets		
Customer receivables	**$ 172**	$ 147
Other	**142**	109
Total current assets	**314**	256
Property, Plant and Equipment		
Property, plant and equipment	**1,204**	1,160
Accumulated depreciation, depletion and amortization	**(358)**	(367)
Total property, plant and equipment, net	**846**	793
Deferred Charges and Other Assets		
Regulatory assets	**156**	109
Other	**100**	2
Total deferred charges and other assets	**256**	111
Assets held for sale	**$1,416**	$1,160
LIABILITIES		
Current Liabilities	**$ 192**	$ 210
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**289**	208
Other	**89**	74
Total deferred credits and other liabilities	**378**	282
Liabilities held for sale	**$ 570**	$ 492

EITF Issue No. 03-13, *Applying the Conditions of Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations*, provides that the results of operations of a component of an entity that has been disposed of or is classified as held for sale shall be reported in discontinued operations if both of the following conditions are met: (a) the operations and cash flows of the components have been (or will be) eliminated from the ongoing operations of the entity as a result of the disposal transaction and (b) the entity will not have any significant continuing involvement in the operations of the component after the disposal transaction. While we do not expect to have significant continuing involvement with Peoples or Hope after their disposal, we do expect to have continuing cash flows related primarily to our sale to them of natural gas production from our Appalachian E&P operations, as well as natural gas transportation and storage services provided to them by our gas transmission operations. Due to these expected significant continuing cash flows, the results of Peoples and Hope have not been reported as discontinued operations in our Consolidated Statements of Income. We will continue to assess the level of our involvement and continuing cash flows with Peoples and Hope for one year after the date of sale in accordance with EITF 03-13, and if circumstances change, we may be required to reclassify the results of Peoples and Hope as discontinued operations in our Consolidated Statements of Income.

The following table presents selected information regarding the results of operations of Peoples and Hope:

Year Ended December 31,	2008	2007	2006
(millions)			
Operating revenue	**$726**	$673	$ 698(1)
Income (loss) before income taxes	**128(3)**	78	(112)(2)

(1) Recast to reflect our revised derivative income statement classification policy as discussed in Note 2 to our Consolidated Financial Statements.
(2) Includes a $166 million charge, recorded in other operations and maintenance in our Consolidated Statement of Income, resulting from the write-off of certain regulatory assets related to the planned sale of Peoples and Hope to Equitable, since the recovery of those assets was no longer probable under the terms of that agreement.
(3) Includes a $47 million benefit related to the re-establishment of certain regulatory assets in connection with the pending sale of Peoples and Hope to BBIFNA, which we now expect to be recovered through future rates under the terms of this agreement.

During 2006, we established additional deferred tax liabilities based on the anticipated treatment of the pending sale to Equitable as a stock sale for tax purposes. As discussed in Note 7, with the termination of the agreement to sell Peoples and Hope to Equitable in January 2008, we reversed those deferred tax liabilities based on our expectation that the form of the ultimate disposal of these subsidiaries would be structured so that the taxable gain would instead be determined by reference to the basis in the subsidiaries' underlying assets.

NOTE 6. OPERATING REVENUE

Our operating revenue consists of the following:

Year Ended December 31,	2008	2007(1)	2006(1)
(millions)			
Electric sales:			
Regulated	**$ 6,797**	$ 6,044	$ 5,451
Nonregulated	**3,543**	2,873	2,636
Gas sales:			
Regulated	**1,307**	1,174	1,397
Nonregulated	**3,020**	2,878	4,398
Other energy-related commodity sales	**294**	574	1,936
Gas transportation and storage	**1,134**	1,031	943
Other	**195**	242	515
Total operating revenue	**$16,290**	$14,816	$17,276

(1) Recast to reflect our revised derivative income statement classification policy as discussed in Note 2 to our Consolidated Financial Statements.

NOTE 7. INCOME TAXES

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

Year Ended December 31,	2008	2007	2006
(millions)			
Current:			
Federal	**$494**	$ 2,875	$195
State	**116**	217	139
Total current	**610**	3,092	334
Deferred:			
Federal	**281**	(1,283)	536
State	**(7)**	(15)	73
Total deferred	**274**	(1,298)	609
Amortization of deferred investment tax credits	**(5)**	(11)	(16)
Total income tax expense	**$879**	$ 1,783	$927

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

Year Ended December 31,	2008	2007	2006
U.S. statutory rate	**35.0%**	35.0%	35.0%
Increases (reductions) resulting from:			
Goodwill—sale of U.S. non-Appalachian E&P business	—	5.6	—
Recognition of deferred taxes—stock of subsidiaries held for sale	**(5.0)**	(0.2)	5.9
State taxes, net of federal benefit	**2.7**	3.1	5.8
Valuation allowances	**0.5**	(2.8)	(6.6)
Domestic production activities deduction	**(0.5)**	(0.5)	(0.1)
Amortization of investment tax credits	**(0.2)**	(0.2)	(0.5)
Employee stock ownership plan deduction	**(0.5)**	(0.3)	(0.5)
Employee pension and other benefits	**(0.3)**	(0.2)	(0.3)
Other, net	**0.7**	0.2	(1.1)
Effective tax rate	**32.4%**	39.7%	37.6%

In 2008, our effective tax rate reflected the reversal of $136 million of deferred tax liabilities, recognized in 2006, associated with the excess of our financial reporting basis over the tax basis in the stock of Peoples and Hope, in accordance with EITF Issue No. 93-17, *Recognition of Deferred Tax Assets for a Parent Company's Excess Tax Basis in the Stock of a Subsidiary that is Accounted for as a Discontinued Operation.* Although these subsidiaries are not classified as discontinued operations, EITF 93-17 requires that the deferred tax impact of the excess of the financial reporting basis over the tax basis of a parent's investment in a subsidiary be recognized when it is apparent that this difference will reverse in the foreseeable future. In 2006, based on the intended form of the sale to Equitable, we recognized these deferred tax liabilities since this difference was expected to reverse upon closing of the sale.

In January 2008, Dominion and Equitable agreed to terminate the agreement for the sale of Peoples and Hope. At that time, based on our expectation that the form of any future disposal of these subsidiaries would be structured so that the taxable gain would instead be determined by reference to the basis in the subsidiaries' underlying assets, we reversed the related deferred tax liabilities recognized in 2006. As discussed in Note 5, we have executed a new agreement to sell Peoples and Hope, whereby we will determine our taxable gain by reference to the basis in the subsidiaries' underlying assets.

As the result of West Virginia income tax rate reductions enacted in March 2008, to be phased in during the period 2009 through 2014, we reduced our net deferred tax liabilities by $12 million. In addition, we recognized $11 million of additional deferred tax expense to reflect the enactment of Massachusetts legislation in July 2008 that requires combined reporting and provides for tax rate reductions during the period 2010 through 2012.

In 2007, our effective tax rate reflected the effects of the sale of our U.S. non-Appalachian E&P operations, including the impact of goodwill, not deductible for tax purposes, that reduced the book gain on sale. In addition, we recognized a tax benefit from eliminating $126 million of valuation allowances on deferred tax assets that relate to federal and state loss carryforwards, which have been utilized to partially offset taxes otherwise payable on the gain from the sale.

In 2006, our effective tax rate reflected the tax benefit from a net $163 million decrease in valuation allowances on deferred tax assets resulting from the elimination of valuation allowances related to federal and state tax loss carryforwards then expected to be utilized to offset capital gain income anticipated from the sale of Peoples and Hope, partially offset by valuation allowance increases primarily associated with deferred tax assets recognized as a result of impairments of certain DCI investments discussed in Note 25. This net benefit was partially offset by the establishment of the deferred tax liabilities associated with the excess of our financial reporting basis over our tax basis in the stock of Peoples and Hope, in accordance with EITF Issue No. 93-17.

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

As of December 31,	2008	2007
(millions)		
Deferred income taxes:		
Total deferred income tax assets	**$1,746**	$1,871
Total deferred income tax liabilities	**6,055**	6,173
Total net deferred income tax liabilities	**$4,309**	$4,302
Total deferred income taxes:		
Depreciation method and plant basis differences	**$2,861**	$2,724
Gas and oil E&P related differences	**413**	520
Deferred state income taxes	**488**	506
Deferred fuel, purchased energy and gas costs	**355**	171
Pension benefits	**262**	582
Recognition of deferred taxes—stock of subsidiaries held for sale	**—**	136
Loss and credit carryforwards	**(235)**	(157)
Valuation allowances	**78**	23
Other	**87**	(203)
Total net deferred income tax liabilities	**$4,309**	$4,302

At December 31, 2008, we had the following loss and credit carryforwards:

- Federal loss carryforwards of $38 million that expire if unutilized during the period 2014 through 2021. A valuation allowance on $1 million of carryforwards has been established due to the uncertainty of realizing these future deductions;
- State loss carryforwards of $1.4 billion that expire if unutilized during the period 2009 through 2028. A valuation allowance on $1.1 billion of these carryforwards has been established; and
- State minimum tax credits of $114 million that do not expire and other state income tax credits of $2 million that will expire if unutilized before 2018.

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

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

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

A reconciliation of changes in our unrecognized tax benefits follows:

	2008	2007
(millions)		
Balance at January 1	**$407**	$ 625
Increases—prior period positions	**42**	64
Decreases—prior period positions	**(54)**	(40)
Current period positions	**63**	70
Prior period positions becoming otherwise deductible in current period	**(21)**	(252)
Settlements with tax authorities	**(33)**	(60)
Balance at December 31	**$404**	$ 407

Unrecognized tax benefits, that, if recognized, would affect the effective tax rate were $121 million and $101 million at December 31, 2008 and 2007, respectively, and $76 million at January 1, 2007. As the result of not recognizing these tax benefits, income tax expense increased by $25 million in both 2008 and 2007. The balances also reflect increases for unrecognized benefits associated with claims and reductions for settlements with tax authorities.

For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. Some unrecognized tax benefits reflect uncertainty as to whether the amounts are deductible as ordinary deductions or capital losses. With the realization of gains from the non-Appalachian E&P sales (see Note 5), these prior year amounts, if ultimately determined to be capital losses, would be fully deductible for federal income tax purposes in 2007. When uncertainty about the deductibility of amounts is limited to the timing of such deductibility, any tax liabilities recognized for prior periods would be subject to offset with the availability of refundable amounts from later periods when such deductions could otherwise be taken. Pending resolution of these timing uncertainties, interest is being accrued until the period in which the amounts would become deductible.

For Dominion and its subsidiaries, the U.S. federal statute of limitations has expired for years prior to 1999, except that we have reserved the right to pursue refunds related to certain deductions for the years 1995 through 1998 and tax credits for 1997 and 1998 based on United Kingdom Windfall Profits taxes paid. Based on additional analysis of our tax profile in 2008, we have decided not to pursue a claim for this tax credit.

In 2007, the U.S. Congressional Joint Committee on Taxation (Joint Committee) completed its review of our settlement with the Appellate Division of the Internal Revenue Service (IRS Appeals) for tax years 1993 through 1998. In October of 2007, we received a tax refund of $34 million for 1993 through 1997. Due to carryback adjustments, the tax refund of $8 million for 1998 will not be received until tax years 1999 through 2001 have been settled and reviewed by the Joint Committee.

We have reached a settlement with IRS Appeals regarding certain adjustments proposed during the examination of tax years 1999 through 2001, except we have reserved the right to pursue refunds related to certain deductions. The settlement is being submitted to the Joint Committee for review. With the settlement and payment of resulting tax liabilities, our unrecognized tax benefits would be reduced by approximately $15 million with no impact on our earnings. In addition, we would be entitled to a refund of $60 million, representing amounts paid during the examination and appeals process related to the adjustments disputed in our protest filed with IRS Appeals. The refund will have no impact on our earnings.

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

With our appeals of assessments received from tax authorities, including amounts related to our settlement negotiations with IRS Appeals for 2002 and 2003, we believe that it is reasonably possible that unrecognized tax benefits could decrease by $60 million to $100 million during 2009. The decrease would be the result of successful resolution of proposed adjustments through settlement negotiations or payments made to tax authorities. In addition, unrecognized tax benefits could be reduced by $23 million to recognize prior period amounts becoming otherwise deductible in the current period. Since the uncertainty for the majority of these unrecognized tax benefits involve only the timing of the deductions, we anticipate that the impact on earnings will be limited to revisions of our accrual for interest on tax underpayments and overpayments.

We are currently working with the IRS under its Pre-Filing Program (Program) to enter into an agreement regarding the calculation of our qualified production activities deduction. The objective of the Program is to provide taxpayers with greater certainty regarding a specific issue at an earlier point in time than can be attained under the normal post-filing examination process. If we are able to enter into an agreement with the IRS in 2009 that eliminates or reduces uncertainty about the deduction, it is reasonably possible that our unrecognized tax benefits as of December 31, 2008, could decrease by $10 million to $20 million, which would be reflected in our 2009 earnings.

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

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

State	Earliest Open Tax Year
Pennsylvania	**1999**
Connecticut	**2005**
Massachusetts	**2005**
Virginia	**2005**
West Virginia	**2005**

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

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

NOTE 8. FAIR VALUE MEASUREMENTS

As described in Note 3, we adopted SFAS No. 157 effective January 1, 2008. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, SFAS No. 157 permits the use of a mid-market pricing convention (the mid-point between bid and ask prices). SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of our own nonperformance risk on our liabilities. SFAS No. 157 also requires fair value measurements to assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). We apply fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments, and nuclear decommissioning trust and other investments including those in our pension and other postretirement benefit plan trusts, in accordance with the requirements described above. We apply credit adjustments to our derivative fair values in accordance with the requirements described above. These credit adjustments are currently not material to the derivative fair values.

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

For options and contracts with option-like characteristics where observable pricing information is not available from external sources, we generally use a modified Black-Scholes Model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. We use other option models under special circumstances, including a Spread Approximation Model, when contracts include different commodities or commodity locations and a

Swing Option Model, when contracts allow either the buyer or seller the ability to exercise within a range of quantities. For contracts with unique characteristics, we may estimate fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. For individual contracts, the use of different valuation models or assumptions could have a significant effect on the contract's estimated fair value.

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

- Level 1—Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as the majority of exchange-traded derivatives and listed equities and Treasury securities held in nuclear decommissioning and rabbi trust funds.
- Level 2—Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 primarily include non-exchange traded derivatives such as over-the-counter commodity forwards and swaps, interest rate swaps, foreign currency forwards and options and municipal bonds and short-term debt securities held in nuclear decommissioning and rabbi trust funds.
- Level 3—Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 consist of long-dated commodity derivatives, NGL contracts, natural gas peaking options, FTRs and other modeled commodity derivatives.

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

Fair value measurements are categorized as Level 3 when a significant amount of price or other inputs that are considered to be unobservable are used in their valuations. Long-dated commodity derivatives are based on unobservable inputs due to the length of time to settlement and absence of market activity and are therefore categorized as Level 3. For NGLs, market illiquidity requires a valuation based on proxy markets that do not always correlate to the actual instrument, therefore they are also categorized as Level 3. For the same illiquidity reason, natural gas peaking options at non-Henry Hub locations are valued using Henry Hub (NYMEX natural gas delivery point) volatilities, which may or may not be identical to the volatilities at transacted locations, and are therefore considered to be unobservable inputs. FTRs are categorized as Level 3 fair value measurements because the only relevant pricing available comes from ISO auctions, which is accurate for day-one valuation, but generally is not considered to be representative of the ultimate settlement values. Other modeled commodity derivatives have unobservable inputs in their valuation, mostly due to non-transparent and illiquid markets.

As of December 31, 2008, our net balance of commodity derivatives categorized as Level 3 fair value measurements was a net asset of $99 million. A hypothetical 10% increase in commodity prices would decrease the net asset by $21 million, while a hypothetical 10% decrease in commodity prices would increase the net asset by $20 million.

SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy and requires a separate reconciliation of fair value measurements categorized as Level 3. Assets held in our pension and other postretirement benefit plans are subject to the fair value measurement requirements of SFAS No. 157, but are currently not subject to fair value disclosure requirements. Therefore they are not included in the level summaries or tables presented below. See Note 22 for further information on our pension and other postretirement benefit plans. The following table presents our assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and non-current portions as of December 31, 2008:

(millions)	Level 1	Level 2	Level 3	Total
Assets:				
Derivatives	$125	$1,672	$243	$2,040
Investments	725	1,501	—	2,226
Total assets	$850	$3,173	$243	$4,266
Liabilities:				
Derivatives	$ 7	$1,146	$144	$1,297

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

(millions)	Derivatives(1)
Year Ended December 31, 2008	
Balance at January 1, 2008	$ (61)
Total realized and unrealized gains or (losses):	
Included in earnings	(88)
Included in other comprehensive income (loss)	274
Included in regulatory and other assets/liabilities	(59)
Purchases, issuances and settlements	85
Transfers out of Level 3	(52)
Balance at December 31, 2008	$ 99
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	$ (28)

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

The following table presents gains and losses included in earnings in the Level 3 fair value category for the year ended December 31, 2008:

	Operating Revenue	Electric Fuel and Energy Purchases	Purchased Gas	Total
(millions)				
Year Ended December 31, 2008				
Total gains or (losses) included in earnings	**$(44)**	**$(28)**	**$(16)**	**$(88)**
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	**(6)**	**(6)**	**(16)**	**(28)**

Fair Value of Financial Instruments

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

At December 31,	2008		2007	
	Carrying Amount	**Estimated Fair Value[1]**	Carrying Amount	Estimated Fair Value[1]
(millions)				
Long-term debt[2]	**$14,334**	**$14,260**	$13,236	$13,377
Junior subordinated notes payable to:				
Affiliates[3]	**268**	**234**	678	681
Other[4]	**798**	**409**	798	804
Subsidiary preferred stock[5]	**257**	**231**	257	257

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

(2) Includes securities due within one year and amounts which represent the unamortized discount and premium. Also includes the valuation of certain fair value hedges associated with our fixed rate debt, of approximately $15 million and $11 million at December 31, 2008, and 2007, respectively.

(3) Includes the valuation of certain fair value hedges associated with our fixed rate debt, of approximately $(2) million at December 31, 2007.

(4) See Note 18 for a description of the coupon rates to be applicable to these securities after their respective first call date. Due to the significant widening of credit spreads during 2008, the established spreads (2.825% for the June hybrids and 2.3% for the September hybrids) are not considered sufficient to ensure redemption at each security's respective first call date; thus, the securities are now trading at a yield to maturity rather than a yield to first call date. As a result, the estimated fair value of these securities is significantly lower at December 31, 2008 as compared to 2007.

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

NOTE 9. HEDGE ACCOUNTING ACTIVITIES

We are exposed to the impact of market fluctuations in the price of electricity, natural gas 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. As discussed in Note 2, for jurisdictions subject to cost-based regulation, changes in the fair value of derivatives designated as hedges are deferred as regulatory assets or regulatory liabilities until the related transactions impact earnings. Selected information about our hedge accounting activities follows:

Year Ended December 31,	**2008**	2007	2006
(millions)			
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:			
Fair value hedges	**$ (6)**	$ 6	$(22)
Cash flow hedges[1]	**(4)**	50	44
Net ineffectiveness	**$(10)**	$56	$ 22

(1) Represents hedge ineffectiveness, primarily due to changes in the fair value differential between the delivery location and commodity specifications of derivatives held by our E&P operations and the delivery location and commodity specifications of our forecasted gas and oil sales.

In 2008, 2007 and 2006, amounts excluded from the measurement of effectiveness did not have a significant impact on net income. These amounts include gains or losses attributable to changes in the time value of options and changes in the differences between spot prices and forward prices.

See Note 5 for a discussion of the discontinuance of hedge accounting for non-Appalachian E&P gas and oil derivatives during 2007.

In 2007, as a result of the termination of the long-term power sales agreement associated with State Line, we discontinued applying the normal purchase and normal sale exception allowed under SFAS No. 133 to this agreement and recorded a $231 million ($137 million after-tax) charge in operating revenue in our Consolidated Statement of Income. During the fourth quarter of 2007, we paid approximately $229 million primarily in exchange for the termination of the power sales agreement, acquisition of coal inventory and assignment of certain coal supply, transportation and railcar lease contracts.

In June 2006, we recorded a $60 million ($37 million after-tax) charge in interest expense—junior subordinated notes payable in our Consolidated Statement of Income, eliminating the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts that sold trust preferred securities.

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

	AOCI After Tax	Portion Expected to be Reclassified to Earnings during the Next 12 Months After Tax	Maximum Term
(millions)			
Commodities:			
Gas	**$ 22**	**$ 12**	**54 months**
Electricity	**363**	**248**	**36 months**
Natural gas liquids	**117**	**41**	**36 months**
Other	**2**	**1**	**77 months**
Interest rate	**1**	**(3)**	**360 months**
Foreign currency	**2**	**1**	**59 months**
Total	**$507**	**$300**	

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

Note 10. Earnings Per Share

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

Year Ended December 31,	2008	2007	2006
(millions, except per share amounts)			
Income from continuing operations before extraordinary item	**$1,836**	$2,705	$1,530
Loss from discontinued operations, net of tax	**(2)**	(8)	(150)
Extraordinary item, net of tax	**—**	(158)	—
Net income	**$1,834**	$2,539	$1,380
Basic EPS			
Average shares of common stock outstanding—basic	**577.8**	650.8	699.5
Income from continuing operations before extraordinary item	**$ 3.17**	$ 4.15	$ 2.19
Loss from discontinued operations, net of tax	**—**	(0.01)	(0.22)
Extraordinary item, net of tax	**—**	(0.24)	—
Net income	**$ 3.17**	$ 3.90	$ 1.97
Diluted EPS			
Average shares of common stock outstanding	**577.8**	650.8	699.5
Net effect of potentially dilutive securities(1)	**3.0**	4.4	3.7
Average shares of common stock outstanding—diluted	**580.8**	655.2	703.2
Income from continuing operations before extraordinary item	**$ 3.16**	$ 4.13	$ 2.17
Loss from discontinued operations, net of tax	**—**	(0.01)	(0.21)
Extraordinary item, net of tax	**—**	(0.24)	—
Net income	**$ 3.16**	$ 3.88	$ 1.96

(1) Potentially dilutive securities consist of options, restricted stock and contingently convertible senior notes. 2006 potentially dilutive securities also included equity-linked securities.

Potentially dilutive securities with the right to purchase approximately 2 million average common shares for the year ended December 31, 2006, were not included in the 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. There were no such anti-dilutive securities outstanding for the years ended December 31, 2008 or 2007.

Note 11. Investments

Marketable Equity and Debt Securities

Trading Securities

Marketable equity and debt securities and cash equivalents held in our rabbi trusts and classified as trading totaled $95 million and $156 million at December 31, 2008 and 2007, respectively.

Available-for-Sale Securities

Marketable equity and debt securities and cash equivalents in nuclear decommissioning trust funds, retained interests from prior securitizations of financial assets and subordinated notes related to certain CDOs, all of which are classified as available for sale, are summarized below. There were no unrealized losses included in AOCI as of December 31, 2008 or 2007.

	Fair Value	Total Unrealized Gains
(millions)		
2008		
Equity securities	**$1,048**	**$ 26**
Debt securities	**1,043**	**42**
Cash equivalents and other	**47**	**—**
Total	**$2,138**	**$ 68(1)**
2007		
Equity securities	$1,784	$486
Debt securities	1,047	33
Cash equivalents and other	57	—
Total	$2,888	$519(1)

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

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. DCI held $38 million of these debt securities at December 31, 2006. During 2007, DCI recognized impairment losses of $27 million ($16 million after-tax) due to changes in market valuations. DCI also sold three of the residual trusts in 2007. DCI still owned six residual trusts with no book basis at December 31, 2008 and 2007.

The fair value of all other debt securities at December 31, 2008, by contractual maturity is as follows:

	Amount
(millions)	
Due in one year or less	**$ 92**
Due after one year through five years	**257**
Due after five years through ten years	**310**
Due after ten years	**384**
Total	**$1,043**

Presented below is selected information regarding our marketable equity and debt securities.

Year Ended December 31,	**2008**	2007	2006
(millions)			
Trading securities:			
Net unrealized gain (loss)	**$ (26)**	$ (3)	$ 9
Available-for-sale securities:			
Proceeds from sales	**916**	916	1,025
Realized gains[1]	**140**	100	90
Realized losses[1]	**404**	144	77

(1) Includes realized gains and losses recorded to the decommissioning trust regulatory liability in 2008 and 2007, as discussed in Note 2.

Equity Method Investments

Investments that we account for under the equity method of accounting are as follows:

Company	Ownership %	Investment Balance		Description
As of December 31,		**2008**	2007	
		(millions)		
Iroquois Gas Transmission System, LP	24.72%	**$114**	$ 97	Gas transmission system
Elwood Energy LLC	50%	**83**	77	Natural gas-fired merchant generation peaking facility
Fowler I Holdings LLC	50%	**292**	—	Wind-powered merchant generation facility
NedPower Mount Storm LLC	50%	**154**	67	Wind-powered merchant generation facility
Other	various	**83**	90	
Total		**$726**	$331	

Equity earnings on these investments totaled $52 million in 2008, $35 million in 2007 and $37 million in 2006. We received dividends from these investments of $12 million, $16 million and $21 million in 2008, 2007 and 2006, respectively. As of December 31, 2008 and 2007, the carrying amount of our investments exceeded our share of underlying equity in net assets by approximately $45 million and $9 million, respectively. The differences relate to our wind projects and primarily reflect our capitalized interest during construction and the excess of our cash contributions over the book value of development assets contributed by our partners for these projects. The differences are generally being amortized over the useful lives of the underlying assets.

During 2008, we recognized a $7 million gain on the sale of one of our equity method investments. During 2007, we recognized an impairment loss of $11 million in connection with the expected sale of one of our equity method investments. During 2006, we sold two of our equity method investments, resulting in a net loss of $3 million.

Cost-Method Investments

At December 31, 2008 and 2007, the carrying value of our cost-method investments totaled $130 million and $34 million, respectively, which approximated their estimated fair value.

Note 12. Property, Plant and Equipment

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

At December 31,	**2008**	2007
(millions)		
Utility:		
Generation	**$10,949**	$10,237
Transmission	**4,274**	3,817
Distribution	**8,750**	8,332
Storage	**1,195**	1,146
Nuclear fuel	**943**	930
Gas gathering and processing	**443**	647
General and other	**702**	732
Other—including plant under construction	**2,403**	1,819
Total utility	**29,659**	27,660
Nonutility:		
Exploration and production properties being amortized:		
Proved	**1,726**	1,789
Unproved	**—**	—
Unproved exploration and production properties not being amortized	**11**	10
Merchant generation—nuclear	**1,124**	1,077
Merchant generation—other	**1,609**	1,393
Nuclear fuel	**583**	482
Other—including plant under construction	**736**	920
Total nonutility	**5,789**	5,671
Total property, plant and equipment	**$35,448**	$33,331

Following the sale of our non-Appalachian E&P operations, costs of unproved properties capitalized under the full cost method of accounting that were excluded from amortization at December 31, 2008 and 2007 were not material. There were no significant properties under development, as defined by the SEC, excluded from amortization at December 31, 2008 and 2007. 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 U.S. and Canadian cost centers were as follows:

Year Ended December 31,	**2008**	2007	2006
(Per mcf equivalent)			
U.S. cost center	**$1.93**	$1.90	$1.65
Canadian cost center[1]	**—**	1.89	2.19

(1) Reflects the amortization rate for capitalized costs for our Canadian cost center as of June 2007. As a result of the sale of our Canadian E&P operations in June 2007, we discontinued the amortization of capitalized unproved property costs for the Canadian cost center.

Volumetric Production Payment Transactions

We previously entered into VPP transactions in 2005, 2004 and 2003 for approximately 76 bcf for the period March 2005 through February 2009, 83 bcf for the period May 2004 through April 2008 and 66 bcf for the period August 2003 through July 2007, respectively. While we were obligated under the agreements to deliver to the purchaser its portion of future natural gas production from the properties, we retained control of the properties and rights to future development drilling. If production from the properties subject to the sale was inadequate to deliver the natural gas scheduled for delivery to the purchaser, we had no obligation to make up the shortfall. Cash proceeds received from these VPP transactions were recorded as deferred revenue. We recognized revenue as natural gas was produced and delivered to the purchaser. The remaining deferred revenue amount was $248 million at December 31, 2006. During 2007, in conjunction with the sale of our non-Appalachian E&P operations, we paid $250 million to terminate the VPP agreements and have retained the repurchased fixed-term overriding royalty interests formerly associated with these agreements. Production from fixed-term overriding royalty interests formerly associated with our VPP agreements is expected to decline 87% in 2009, reflecting the expiration of these interests in February 2009.

Assignment of Marcellus Acreage

In 2008, we completed a transaction with Antero to assign drilling rights to approximately 117,000 acres in the Marcellus Shale formation located in West Virginia and Pennsylvania. We received proceeds of approximately $347 million and recognized $4 million of associated closing costs. The net proceeds were credited to our full cost pool, reducing property, plant and equipment in our Consolidated Balance Sheet, as the transaction did not significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil. Under the agreement, we will receive a 7.5% overriding royalty interest on future natural gas production from the assigned acreage. We will retain the drilling rights in traditional formations both above and below the Marcellus Shale interval and will continue our conventional drilling program on the acreage.

Sale of E&P Properties

In 2007, we sold our non-Appalachian natural gas and oil E&P operations and assets for approximately $13.9 billion, which included the sale of a portion of our U.S. full cost pool and our entire Canadian full cost pool.

In 2006, we received approximately $393 million of proceeds from the sale of gas and oil properties, primarily resulting from the fourth quarter sale of certain properties located in Texas and New Mexico. The proceeds were credited to our U.S. full cost pool.

Jointly-Owned Power Stations

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

(millions, except percentages)	Bath County Pumped Storage Station	North Anna Power Station	Clover Power Station	Millstone Unit 3
Ownership interest	**60.0%**	**88.4%**	**50.0%**	**93.5%**
Plant in service	**$1,011**	**$ 2,107**	**$ 560**	**$ 702**
Accumulated depreciation	**(427)**	**(1,028)**	**(155)**	**(133)**
Nuclear fuel	**—**	**436**	**—**	**271**
Accumulated amortization of nuclear fuel	**—**	**(343)**	**—**	**(192)**
Plant under construction	**9**	**154**	**1**	**52**

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 2008. The changes in the carrying amount of goodwill during 2008 and 2007 are presented below:

	Dominion Generation	Dominion Energy	Dominion Delivery	Dominion E&P	DVP	Corporate and Other	Total
(millions)							
Balance at December 31, 2006	$1,479	$740	$ 1,184	$ 877	$ —	$ 18	$4,298
Sale of non-Appalachian E&P business	—	—	—	(760)	—	—	(760)
Sale of Peaker facilities	(24)	—	—	—	—	—	(24)
Sale of Gichner and Dallastown	—	—	—	—	—	(18)	(18)
Reallocation due to segment realignment(1)	—	121	(1,184)	(117)	1,084	96	—
Balance at December 31, 2007	$1,455	$861	$ —	$ —	$1,084	$ 96	$3,496
Acquisition of business	—	—	—	—	7	—	7
Balance at December 31, 2008	**$1,455**	**$861**	**$ —**	**$ —**	**$1,091**	**$ 96**	**$3,503**

(1) Reflects the reallocation of goodwill due to our fourth quarter 2007 segment realignment reflecting the transfer of:

- *Regulated electric distribution and nonregulated retail energy marketing operations from Dominion Delivery to DVP;*
- *Dominion East Ohio from Dominion Delivery to Dominion Energy;*
- *Regulated electric transmission operations from Dominion Energy to DVP;*
- *Appalachian E&P operations from Dominion E&P to Dominion Energy; and*
- *Peoples and Hope operations from Dominion Delivery to Corporate and Other.*

Other Intangible Assets

All of our intangible assets, other than goodwill, are subject to amortization over their estimated useful lives. Amortization expense for intangible assets was $95 million, $115 million and $106 million for 2008, 2007 and 2006, respectively. In 2008, we acquired $94 million of intangible assets, primarily representing software and emissions allowances, with an estimated weighted-average amortization period of approximately 5.64 and 4.16 years, respectively. The components of our intangible assets are as follows:

At December 31,	2008		2007	
	Gross Carrying Amount	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
(millions)				
Software and software licenses	**$ 623**	**$306**	$ 591	$340
Emissions allowances	**182**	**30**	168	39
Other	**276**	**33**	262	44
Total	**$1,081**	**$369**	$1,021	$423

Annual amortization expense for these intangible assets is estimated to be $95 million for 2009, $75 million for 2010, $52 million for 2011, $39 million for 2012 and $25 million for 2013.

NOTE 14. REGULATORY ASSETS AND LIABILITIES

Our regulatory assets and liabilities include the following:

At December 31,	2008	2007
(millions)		
Regulatory assets:		
Deferred cost of fuel used in electric generation(1)	$ 133	$ —
Derivatives(2)	79	—
Unrecovered gas costs	107	63
Customer bad debts(3)	21	—
Regulatory assets—current(4)	340	63
Unrecognized pension and other postretirement benefit costs(5)	1,090	272
PIPP(6)	131	—
Customer bad debts(3)	5	70
RTO start-up costs and administration fees(7)	135	103
Deferred cost of fuel used in electric generation(1)	676	386
Other postretirement benefit costs(8)	38	47
Income taxes recoverable through future rates(9)	35	30
AFUDC(10)	19	1
Other	97	48
Regulatory assets—non-current	2,226	957
Total regulatory assets	$2,566	$1,020
Regulatory liabilities:		
Provision for future cost of removal and AROs(11)	688	623
Decommissioning trust(12)	213	487
Other(13)	63	116
Total regulatory liabilities	$ 964	$1,226

(1) As discussed under Virginia Fuel Expenses in Note 23, in June 2007 the Virginia Commission approved a fuel factor increase of approximately $219 million, effective July 1, 2007, with the balance of approximately $443 million to be deferred and subsequently recovered, without interest, during the period commencing July 1, 2008 and ending June 30, 2011. Beginning July 1, 2008 the recovery of $231 million of the approximately $697 million prior year under-recovered fuel balance commenced, with the balance to be recovered in subsequent periods as provided by Virginia law.

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

(3) Instead of recovering bad debt costs through our base rates, the 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, through the tracker rider, beginning in July 2004 through June 2010. Remaining costs to be recovered totaled $5 million at December 31, 2008.

(4) Reported in other current assets.

(5) Represents unrecognized pension and other postretirement benefit costs expected to be recovered through future rates by certain of our rate-regulated subsidiaries.

(6) Under the Ohio Percentage of Income Payment Plan (PIPP), eligible customers can receive energy assistance based on their ability to pay. The difference between the customer's total bill and the PIPP plan amount is deferred and collected under the PIPP rider according to Dominion East Ohio tariff provisions. Historically, the rider rate was designed to recover deferred costs over an annual period; however, due to the increase in unrecovered costs at the time the existing rate was established, the Ohio Commission requested the use of a three-year recovery period.

(7) The FERC has approved our recovery of start-up costs incurred in connection with joining an RTO and ongoing administrative charges paid to PJM through a DRC. We have deferred $104 million in start-up costs and administrative charges and $31 million of associated carrying costs. We expect recovery from Virginia jurisdictional retail customers to commence on the effective date of approval by the Virginia Commission of a rate adjustment clause designed to recover retail transmission costs as authorized under the 2007 Virginia Regulation Act.

(8) 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.

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

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

(11) 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.

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

(13) Includes $20 million and $3 million reported in other current liabilities in 2008 and 2007, respectively.

At December 31, 2008, approximately $898 million of our regulatory assets represented past expenditures on which we do not earn a return. These expenditures consist primarily of deferred fuel costs, unrecovered gas costs and customer bad debts. Unrecovered gas costs and the ongoing portion of bad debts are recovered within two years. Previously deferred bad debts will be recovered through 2010.

NOTE 15. ASSET RETIREMENT OBLIGATIONS

Our AROs are primarily associated with the decommissioning of our nuclear generation facilities. In addition, our AROs include plugging and abandonment of gas and oil wells; interim retirements of natural gas gathering, transmission, distribution and storage pipeline components; 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 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 occur when the expected retirement or abandonment dates are determined by our operational planning. The changes to our AROs during 2008 were as follows:

	Amount
(millions)	
Asset retirement obligations at December 31, 2007(1)	$1,737
Obligations incurred during the period	2
Obligations settled during the period	(10)
Revisions in estimated cash flows	1
Accretion	94
Other	(2)
Asset retirement obligations at December 31, 2008(1)	$1,822

(1) Includes $15 million and $20 million reported in other current liabilities at December 31, 2007 and 2008, respectively.

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2008 and 2007, the aggregate fair value of these trusts, consisting primarily of equity and debt securities, totaled $2.2 billion and $2.9 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.

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

As discussed in Note 25, DCI held an investment in the subordinated notes of a third-party CDO. We previously concluded that the CDO entity was a VIE and that DCI was the primary beneficiary of the CDO entity, which we consolidated in accordance with FIN 46R at December 31, 2007. In March 2008, we entered into an agreement to sell our remaining interest in the subordinated notes effectively eliminating the variability of our interest, and therefore deconsolidated the CDO entity as of March 31, 2008.

NOTE 17. SHORT-TERM DEBT AND CREDIT AGREEMENTS

We use short-term debt to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, we utilize cash and letters of credit to fund collateral requirements under our commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels, our credit quality and the credit quality of our counterparties.

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

At December 31, 2008, we had committed lines of credit totaling $5.2 billion, excluding commitments provided by Lehman. These lines of credit support commercial paper borrowings, bank loans and letter of credit issuances. At December 31, 2008 and 2007, we had the following commercial paper, bank loans, and letters of credit outstanding, as well as capacity available under our credit facilities:

	Facility Limit(1)	Outstanding Commercial Paper	Outstanding Bank Borrowings	Outstanding Letters of Credit	Facility Capacity Available
(millions)					
2008					
Five-year joint revolving credit facility(2)	**$2,837**	**$297**	**$ —**	**$187**	**$2,353**
Five-year Dominion credit facility(3)	**1,700**	**208**	**1,470**	**22**	**—**
Five-year Dominion bilateral facility(4)	**200**	**55**	**—**	**75**	**70**
364-day Dominion credit facility(5)	**467**	**—**	**—**	**—**	**467**
Totals	**$5,204**	**$560(6)**	**$1,470**	**$284**	**$2,890**
2007					
Five-year joint revolving credit facility(2)	$3,000	$757	$ —	$229	$2,014
Five-year Dominion credit facility(3)	1,700	—	1,000	1	699
Five-year Dominion bilateral facility(4)	200	—	—	—	200
Totals	$4,900	$757(5)	$1,000	$230	$2,913

(1) 2008 amounts exclude commitments provided by Lehman.
(2) This credit facility was entered into February 2006 and terminates in February 2011. This credit facility can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion of letters of credit.
(3) This credit facility was entered into in August 2005 and terminates in August 2010. This facility can be used to support bank borrowings, the issuance of letters of credit and commercial paper. The weighted-average interest rates of the outstanding bank borrowing supported by this facility were 3.95% and 5.69% at December 31, 2008 and 2007, respectively.
(4) This facility was entered into in December 2005 and terminates in December 2010. This credit facility can be used to support commercial paper and letter of credit issuances.
(5) This credit facility was entered into in July 2008 and terminates in July 2009. This credit facility can be used to support bank borrowings and the issuance of commercial paper.
(6) The weighted-average interest rates of the outstanding commercial paper supported by our credit facilities were 5.87% and 5.66% at December 31, 2008 and 2007, respectively.

In addition to the facilities above, we also entered into a $100 million bilateral credit facility in August 2004 that was to terminate in August 2009. In May 2008, we terminated this facility. At December 31, 2007, there were no letters of credit outstanding under this facility.

In addition to the credit facility commitments of $5.2 billion disclosed above, we also have a $182 million five-year credit facility, excluding commitments provided by Lehman, that supports certain Virginia Power tax-exempt financings.

Note 18. Long-Term Debt

At December 31,	2008 Weighted-Average Coupon[1]	2008	2007
(millions, except percentages)			
Dominion Resources, Inc.:			
Unsecured Senior Notes:			
4.125% to 8.125%, due 2008 to 2013	**5.54%**	**$ 1,832**	$ 2,562
5.15% to 8.875%, due 2014 to 2038[2]	**6.34%**	**4,246**	2,747
Variable rates, due 2008 and 2010	**3.80%**	**300**	400
Unsecured Convertible Senior Notes, 2.125%, due 2023[3]		**202**	220
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts, 7.83% to 8.4%, due 2027 to 2031	**7.85%**	**268**	268
Enhanced Junior Subordinated Notes, 6.3% to 7.5%, due 2066	**6.75%**	**800**	800
Unsecured Debentures and Senior Notes[4]:			
6.0% to 6.85%, due 2008 to 2013	**6.21%**	**691**	742
5.0% to 6.875%, due 2014 to 2027	**5.23%**	**689**	689
Virginia Electric and Power Company:			
Unsecured Senior and Medium-Term Notes:			
4.5% to 5.73%, due 2008 to 2013	**4.87%**	**1,230**	1,350
5.25% to 8.875%, due 2015 to 2038	**6.37%**	**4,272**	2,985
Unsecured Callable and Puttable Enhanced Securities℠, 4.10%, due 2038[5]		**—**	225
Tax-Exempt Financings:[6]			
Variable rate, due 2008		**—**	60
Variable rates, due 2015 to 2027	**2.05%**	**119**	137
5.25% to 7.65%, due 2008 to 2010	**5.54%**	**112**	205
3.6% to 6.5%, due 2017 to 2035	**5.13%**	**393**	223
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.375%, due 2042[7]		**—**	412
Dominion Energy, Inc.:			
Secured Senior Note, 7.33%, due 2020[8]		**194**	204
Tax-Exempt Financings, 5.0%, due 2033 to 2036		**74**	47
Dominion Capital, Inc.:			
Senior Revolving Notes, Variable rate, due 2017[9]		**—**	75
Senior Note, Variable rate, due 2017[9]		**—**	385
		15,422	14,736
Fair value hedge valuation[10]		**15**	9
Amounts due within one year[11]	**5.36%**	**(444)**	(1,477)
Unamortized discount and premium, net		**(37)**	(33)
Total long-term debt		**$14,956**	$13,235

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2008.

(2) At the option of holders, $510 million of Dominion's 5.25% senior notes due 2033 and $600 million of Dominion's 8.875% senior notes due 2019 are subject to redemption at 100% of the principal amount plus accrued interest in August 2015 and January 2014, respectively.

(3) Convertible into a combination of cash and shares of our common stock at any time when the closing price of our common stock equals 120% of the applicable conversion price or higher for at least 20 out of the last 30 consecutive trading days ending on the last trading day of the previous calendar quarter. At the option of holders on December 15, 2008, 2011, 2013 or 2018, these securities are subject to redemption at 100% of the principal amount plus accrued interest. These securities are currently non-callable by the Company until December 15, 2011.

(4) Represents debt assumed by DRI from the merger of our former CNG subsidiary.

(5) On December 15, 2008, option holders did not exercise their rights to purchase and remarket the notes. As a result, the notes were redeemed at par plus accrued interest and we recorded a $23 million benefit from the early redemption of these securities.

(6) These financings relate to certain pollution control equipment at Virginia Power's generating facilities. The variable rate tax-exempt financings are supported by a $182 million five-year credit facility, excluding commitments provided by Lehman, that terminates in February 2011. In February 2007, we exercised our call option and redeemed $62 million of Virginia Power's tax-exempt financings with a weighted average rate of 7.52%, with proceeds raised through the issuance of commercial paper.

(7) On May 19, 2008, the notes were redeemed at par plus accrued and unpaid distributions.

(8) Represents debt associated with our Kincaid power station. The debt is non-recourse to us and is secured by the facility's assets ($584 million at December 31, 2008) and revenue.

(9) As discussed in Note 25, in March 2008, DCI deconsolidated a CDO entity, previously consolidated in accordance with FIN 46R. The debt was nonrecourse to us.

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

(11) Includes $9 million and $(1) million of net unamortized discount and fair value hedge valuation in 2008 and 2007, respectively.

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

	2009	2010	2011	2012	2013	Thereafter	Total
(millions, except percentages)							
Secured Senior Notes	$ 11	$ 12	$ 13	$ 13	$ 11	$ 134	$ 194
Unsecured Senior Notes	313	1,122	484	1,470	740	9,333	13,462
Tax-Exempt Financings	111	1	—	—	—	586	698
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts	—	—	—	—	—	268	268
Enhanced Junior Subordinated Notes	—	—	—	—	—	800	800
Total	$ 435	$1,135	$ 497	$1,483	$ 751	$11,121	$15,422
Weighted-average coupon	5.36%	4.97%	6.35%	5.62%	5.01%	6.17%	

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

Convertible Securities

In 2004, we entered into an exchange transaction with respect to $220 million of our outstanding contingent convertible senior notes in contemplation of the transition method provided by EITF Issue No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share.* We exchanged the outstanding notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. At issuance, the notes were valued at a conversion rate of 27.173 shares of common stock per $1,000 principal amount of senior notes, which represented a conversion price of $36.80, recast to reflect our November 2007 stock split. Amounts payable in excess of the principal amount will be paid in common stock. The conversion rate is subject to adjustment upon certain events such as subdivisions, splits, combinations of common stock or the issuance to all common stock holders of certain common stock rights, warrants or options and certain dividend increases. As of December 31, 2008, the conversion rate had been adjusted to 27.728, primarily due to individual dividend payments above the level paid at issuance. In December 2008, our Board declared dividends payable March 20, 2009 of 43.75 cents per share of common stock which will increase the conversion rate to 27.831 effective as of February 25, 2009.

The 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, when appropriate. Under this method, the number of shares included in the denominator of the diluted EPS calculation is calculated as the net shares issuable for the reporting period based upon the average market price for the period. This results in an increase in the average shares outstanding used in the calculation of our diluted EPS when the conversion price of $36.80 is lower than the average market price of our common stock over the period, and results in no adjustment when the conversion price exceeds the average market price.

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 closing price of our common stock exceeds the applicable conversion price ($43.12 as of February 25, 2009) for at least 20 out of the last 30 consecutive trading days ending on the last trading day of the previous calendar quarter;

(2) The senior notes are called for redemption by us;

(3) The occurrence of specified corporate transactions; or

(4) The credit rating assigned to the senior notes by Moody's is below Baa3 and by Standard & Poor's is below BBB- or the ratings are discontinued for any reason.

As of December 31, 2008, the closing price of our common stock was not equal to $43.28 per share or higher for at least 20 out of the last 30 consecutive trading days. Therefore, the senior notes are not eligible for conversion during the first quarter of 2009. However, during 2008, approximately $18 million of the contingent convertible senior notes were converted by holders. Beginning in 2007, the notes have been eligible for contingent interest if the average trading price as defined in the indenture equals or exceeds 120% of the principal amount of the senior notes. In December 2008, we amended the terms of our Series C 2.125% Convertible Senior Notes and the related Twenty-Seventh Supplemental Indenture. The amendment eliminates our ability to redeem the Notes before December 2011. The amendment also establishes a new repurchase date in December 2011. As a result, holders have the right to require us to purchase these senior notes for cash at 100% of the principal amount plus accrued interest in December 2008, 2011, 2013 or 2018, or if we undergo certain fundamental changes. In December 2008, $175 thousand of the debt was redeemed due to holders exercising their put option.

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 trusts sold trust preferred securities representing preferred beneficial interests and 97% beneficial ownership in the assets held by the 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.

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

In July and August 2007, we redeemed approximately 240 thousand units of the $250 million 8.4% Dominion Resources Capital Trust III preferred securities due January 15, 2031. The securities were redeemed at an average price of $1,209 per preferred security plus accrued and unpaid distributions.

In July 2007, we redeemed all 8 million units of the $200 million 7.8% Dominion CNG Capital Trust I preferred securities due October 31, 2041. The securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions.

In October 2006, we redeemed all 12 million units of the $300 million 8.4% Dominion Resources Capital Trust II preferred securities due January 30, 2041. The securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions.

The following table provides summary information about the trust preferred securities and junior subordinated notes outstanding as of December 31, 2008:

Date Established	Capital Trusts	Units	Rate	Trust Preferred Securities Amount	Common Securities Amount
		(thousands)			(millions)
December 1997	Dominion Resources Capital Trust I(1)	**250**	**7.83%**	**$250**	**$7.7**
January 2001	Dominion Resources Capital Trust III(2)	**10**	**8.4%**	**10**	**0.3**

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) $10 million—Dominion Resources, Inc. 8.4% Debentures due 1/15/2031.

We fully and unconditionally guarantee distribution payments on the trust preferred securities, 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 dependent solely upon the payment of amounts by Dominion when they are due on the junior subordinated notes. We may defer interest payments on the junior subordinated notes on one or more occasions for up to five consecutive years and the related trusts must also defer distributions. If the payment on the junior subordinated notes is deferred, Dominion may not make distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, Dominion may not make any payments on, redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the junior subordinated notes.

Enhanced Junior Subordinated Notes

In June 2006 and September 2006, we issued $300 million of 2006 Series A Enhanced Junior Subordinated Notes due 2066 (June hybrids) and $500 million of 2006 Series B Enhanced Junior Subordinated Notes due 2066 (September hybrids), respectively. The June hybrids will bear interest at 7.5% per year until June 30, 2016. Thereafter, they will bear interest at the three-month London Interbank Offered Rate (LIBOR) plus 2.825%, reset quarterly. The September hybrids will bear interest at 6.3% per year until September 30, 2011. Thereafter, they will bear interest at the three-month LIBOR plus 2.3%, reset quarterly. We may defer interest payments on the hybrids on one or more occasions for up to 10 consecutive years. If the interest payments on the hybrids are deferred, we may not make distributions related to our capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, we may not make any payments on or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the hybrids.

NOTE 19. SUBSIDIARY PREFERRED STOCK

Dominion is authorized to issue up to 20 million shares of preferred stock, however, none were issued and outstanding at December 31, 2008 or 2007.

Virginia Power is authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference, and had 2.59 million preferred shares issued and outstanding at December 31, 2008 and 2007. 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, 2008:

Dividend	Issued and Outstanding Shares	Entitled Per Share Upon Liquidation
	(thousands)	
$5.00	**107**	**$112.50**
4.04	**13**	**102.27**
4.20	**15**	**102.50**
4.12	**32**	**103.73**
4.80	**73**	**101.00**
7.05	**500**	**101.77**(1)
6.98	**600**	**101.75**(2)
Flex MMP 12/02, Series A	**1,250**	**100.00**(3)
Total	**2,590**	

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

NOTE 20. SHAREHOLDERS' EQUITY

Issuance of Common Stock

During 2008, we received proceeds of $240 million for 6.2 million shares issued through Dominion Direct®, employee savings plans and the exercise of employee stock options.

In January 2009, we entered into three separate sales agency agreements with BNY Mellon Capital Markets, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. Incorporated (collectively the Sales Agents) pursuant to which we may offer from time to time up to $400 million aggregate amount of our common stock. Sales of common stock can be made by means of privately negotiated transactions, as transactions on the New York Stock Exchange at market prices or in such other transactions as are agreed upon by the Company and the Sales Agents and in conformance with applicable securities laws. We provided sales instructions to one of the Sales Agents during February 2009 and have completed several trades resulting in the issuance of a moderate number of shares.

In February 2009, we also issued approximately 1.6 million shares of common stock to an existing holder of our senior notes, in a privately negotiated transaction, in exchange for approximately $56 million of the principal of two series of our outstanding senior notes, which were retired. The transaction was exempt from registration pursuant to Section 3(a)(9) of the Securities Act and no commission or remuneration was paid in connection with the exchange.

Repurchases of Common Stock

In 2008, we did not repurchase shares of our common stock. In 2007, we repurchased 129 million shares of common stock for approximately $5.8 billion. This amount includes the completion of our equity tender offer in August 2007, in which we purchased approximately 115.5 million shares at a price of $45.50 per share for a total cost of approximately $5.3 billion, excluding fees and expenses related to the tender.

At December 31, 2008, the remaining stock repurchase authorization provided by our Board of Directors is the lesser of 54 million shares or $2.7 billion of our outstanding common stock. Dominion does not expect to repurchase its common stock during 2009, except for shares tendered by employees to satisfy tax withholding obligations on vesting restricted stock, which do not count against our stock repurchase authorization.

Shares Reserved for Issuance

At December 31, 2008, we had approximately 44 million shares reserved and available for issuance for the following: Dominion Direct®, employee stock awards, employee savings plans, director stock compensation plans and contingent convertible senior notes.

Accumulated Other Comprehensive Income (Loss)

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

At December 31,	**2008**	2007
(millions)		
Net unrealized gains (losses) on derivatives—hedging activities, net of tax of $(311) and $30, respectively	**$ 507**	$ (42)
Net unrealized gains on investment securities, net of tax of $(18) and $(116), respectively	**27**	180
Net unrecognized pension and other postretirement benefit costs, net of tax of $562 and $149, respectively	**(803)**	(150)
Total accumulated other comprehensive loss	**$(269)**	$ (12)

Stock-Based Awards

In April 2005, our shareholders approved the 2005 Incentive Compensation Plan (2005 Incentive Plan) for employees and the Non-Employee Directors Compensation Plan (Non-Employee Directors Plan). The 2005 Incentive Plan permits stock-based awards that include restricted stock, performance grants, goal-based stock, stock options and stock appreciation rights. The Non-Employee Directors Plan permits grants of restricted stock and stock options. Under provisions of both plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms are set at the discretion of the Compensation, Governance and Nominating (CGN) Committee of the Board of Directors or the Board of Directors itself, as provided under each plan. At December 31, 2008, approximately 28 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 in length.

Our results for the years ended December 31, 2008, 2007 and 2006 include $46 million, $57 million and $31 million, respectively, of compensation costs and $17 million, $21 million and $11 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in our Consolidated Statements of Income. SFAS No. 123R requires the benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation (excess tax benefits) to be classified as a financing cash flow. In accordance with FSP No. FAS 123R-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, we have elected to use the simplified method to determine the impact of employee stock option awards that were fully vested and outstanding upon the adoption of SFAS No. 123R. During the years ended December 31, 2008, 2007 and 2006, we realized $7 million, $46 million and $8 million, respectively, of excess tax benefits from the vesting of restricted stock awards and exercise of employee stock options. Such amounts are reported as financing cash flows.

Stock Options

The following table provides a summary of changes in amounts of stock options outstanding as of and for the years ended December 31, 2008, 2007 and 2006. No options were granted under any plan in 2008, 2007 or 2006.

	Shares	Weighted-average Exercise Price	Weighted-average Remaining Contractual Life	Aggregated Intrinsic Value[1]
	(thousands)		(years)	(millions)
Outstanding and exercisable at December 31, 2005	16,428	$30.21		
Exercised	(1,895)	$29.88		$ 19
Forfeited/expired	(42)	$30.40		
Outstanding and exercisable at December 31, 2006	14,491	$30.26		
Exercised	(7,453)	$30.06		$108
Forfeited/expired	(17)	$30.44		
Outstanding and exercisable at December 31, 2007	7,021	$30.46		
Exercised	**(1,458)**	**$30.20**		**$ 17**
Forfeited/expired	**(5)**	**$28.85**		
Outstanding and exercisable at December 31, 2008	**5,558**	**$30.53**	**2.2**	**$ 30**

(1) Intrinsic value represents the difference between the exercise price of the option and the market value of our stock.

We issue new shares to satisfy stock option exercises. We received cash proceeds from the exercise of stock options of approximately $43 million, $226 million and $54 million in the years ended December 31, 2008, 2007 and 2006, respectively.

Restricted Stock

The fair value of our restricted stock awards is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of restricted stock activity for the years ended December 31, 2008, 2007 and 2006:

	Shares	Weighted-average Grant Date Fair Value
	(thousands)	
Nonvested at December 31, 2005	2,262	$31.64
Granted	675	35.22
Vested	(361)	30.38
Cancelled and forfeited	(83)	33.77
Nonvested at December 31, 2006	2,493	$32.72
Granted	508	44.53
Vested	(897)	33.00
Cancelled and forfeited	(90)	38.33
Nonvested at December 31, 2007	2,014	$35.31
Granted	**546**	**40.99**
Vested	**(935)**	**32.09**
Cancelled and forfeited	**(69)**	**39.51**
Transferred from goal-based stock to restricted stock	**200**	**34.77**
Nonvested at December 31, 2008	**1,756**	**$38.55**

As of December 31, 2008, unrecognized compensation cost related to nonvested restricted stock awards totaled $26 million and is expected to be recognized over a weighted-average period of 1.5 years. The fair value of restricted stock awards that vested was $40 million, $30 million and $14 million in 2008, 2007 and 2006, respectively. Employees may elect to have shares of restricted stock withheld upon vesting to satisfy tax withholding obligations. The number of shares withheld will vary for each employee depending on the vesting date fair market value of Dominion stock and the applicable federal, state and local tax withholding rates. Shares tendered for taxes are added to the shares remaining to be issued and become available for reissuance as incentive awards.

Goal-Based Stock

Goal-based stock awards are generally granted to key non-officer employees on an annual basis. Goal-based stock awards are also granted in lieu of cash-based performance grants to certain officers who have not achieved a certain targeted level of share ownership. The issuance of awards is based on the achievement of multiple performance metrics during a two-year period, including return on invested capital, book value per share and total shareholder return relative to that of a peer group of companies. Current outstanding goal-based shares include awards granted in April 2007 and April 2008.

The actual number of shares issued will vary between zero and 200% of targeted shares depending on the level of performance metrics achieved. The fair value of goal-based stock is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares.

After the performance period for the April 2006 grants ended on December 31, 2007, the CGN Committee determined the actual performance against metrics established for those awards, and 130 thousand shares of the outstanding goal-based stock awards granted in April 2006 were converted to 200 thousand shares of restricted stock for the remaining term of the vesting period ending in April 2009.

The following table provides a summary of goal-based stock activity for the years ended December 31, 2008, 2007 and 2006:

	Targeted Number of Shares	Weighted-average Grant Date Fair Value
	(thousands)	
Nonvested at December 31, 2005	—	$ —
Granted	200	34.77
Vested	—	—
Cancelled and forfeited	(6)	34.77
Nonvested at December 31, 2006	194	$34.77
Granted	160	44.24
Vested	(32)	34.77
Cancelled and forfeited	(33)	35.03
Nonvested at December 31, 2007	289	$39.16
Granted	**164**	**40.97**
Vested	**(1)**	**43.78**
Cancelled and forfeited	**(7)**	**43.33**
Transferred from goal-based stock to restricted stock	**(130)**	**34.77**
Nonvested at December 31, 2008	**315**	**$42.56**

At December 31, 2008, the targeted number of shares expected to be issued under the April 2007 and April 2008 awards was approximately 315 thousand. In January 2009, the CGN Committee determined the actual performance against metrics established for the April 2007 awards with a performance period that ended December 31, 2008. Based on that determination, the total number of shares to be issued under the goal-based stock awards was approximately 386 thousand.

As of December 31, 2008, unrecognized compensation cost related to nonvested goal-based stock awards totaled $8 million and is expected to be recognized over a weighted-average period of 1.5 years.

Cash-Based Performance Grant

The actual payout of our cash-based performance grants will vary between zero and 200% of the targeted amount based on the level of performance metrics achieved.

The targeted amount of the cash-based performance grant made to officers in April 2006 was $13 million, but the actual payout of the award in February 2008 determined by the CGN Committee was $18 million, based on the level of performance metrics achieved.

In April 2007, a cash-based performance grant was made to officers. Payout of the performance grant occurred in February 2009 based on the achievement of two performance metrics during 2007 and 2008: return on invested capital and total shareholder return relative to that of a peer group of companies. At December 31, 2008, the targeted amount of the grant was $11 million, however, the actual payout was $16 million based on the performance metrics achieved. At December 31, 2008, a liability of $16 million had been accrued for this award.

In April 2008, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2010 based on the achievement of three performance metrics during 2008 and 2009: return on invested capital, book value per share and total shareholder return relative to that of a peer group of companies. At December 31, 2008, the targeted amount of the grant was $12 million and a liability of $5 million had been accrued for this award.

Note 21. Dividend Restrictions

The Virginia Commission may prohibit any public service company, including Virginia Power, from declaring or paying a dividend to an affiliate, if found to be detrimental to the public interest. At December 31, 2008, 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, 2008.

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 or interest payments on enhanced junior subordinated notes.

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 the employee's compensation. Our funding policy is to contribute annually an amount that is in accordance with the provisions of the Employment Retirement Income Security Act of 1974 (ERISA). 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.

Pension and other postretirement benefit costs are affected by employee demographics (including age, compensation levels and years of service), the level of contributions made to the plans and earnings on plan assets. These costs may also be affected by changes in key assumptions, including expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates and the rate of compensation increases.

We use December 31 as the measurement date for all of our employee benefit plans. We use the market-related value of pension plan assets to determine the expected return on 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, which reduces year-to-year volatility. 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. Since the market-related value recognizes changes in fair value over a four-year period, the future market-related value of pension plan assets will be impacted as previously unrecognized changes in fair value are recognized.

Our pension and other postretirement benefit plans hold investments in trusts to fund benefit payments. In 2008, actual returns for our pension plan assets were negative $1.2 billion versus an expected positive return of $411 million, while actual returns for our other postretirement plan assets were negative $213 million versus an expected positive return of $73 million. Differences between actual and expected returns on plan assets are accumulated and amortized during future periods. As such, investment-related declines in these trusts, such as those experienced during 2008, will result in future increases in the periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash to be contributed to the employee benefit plans.

In December 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. We determined that the prescription drug benefit offered under our other postretirement benefit plans is at least actuarially equivalent to Medicare Part D. In 2008, we received a $3 million federal subsidy and expect to continue to receive the subsidy offered under the Medicare Act.

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:

	Pension Benefits		Other Postretirement Benefits	
Year Ended December 31,	**2008**	2007	**2008**	2007
(millions, except percentages)				
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 3,693**	$3,666	**$1,464**	$1,297
Service cost	**102**	112	**60**	55
Interest cost	**236**	222	**93**	77
Benefits paid	**(196)**	(164)	**(73)**	(69)
Actuarial (gains) losses during the year	**54**	(139)	**19**	125
Plan amendments	**4**	4	**(6)**	(14)
Curtailments	**—**	(8)	**(11)**	(7)
Adoption of EITF 06-4(1)	**—**	—	**5**	—
Medicare Part D reimbursement	**—**	—	**3**	—
Benefit obligation at end of year	**$ 3,893**	$3,693	**$1,554**	$1,464
Change in fair value of plan assets:				
Fair value of plan assets at beginning of year	**$ 5,098**	$4,793	**$ 960**	$ 909
Actual return (loss) on plan assets	**(1,179)**	461	**(213)**	59
Employer contributions	**34**	8	**36**	25
Benefits paid	**(196)**	(164)	**(36)**	(33)
Fair value of plan assets at end of year	**$ 3,757**	$5,098	**$ 747**	$ 960
Funded status at end of year	**$ (136)**	$1,405	**$ (807)**	$ (504)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Assets held for sale(2)	**$ 99**	$ —	**$ —**	$ —
Noncurrent pension and other postretirement benefit assets	**512**	1,544	**2**	21
Liabilities held for sale(2)	**—**	—	**(21)**	—
Other current liabilities	**(10)**	(29)	**—**	(2)
Pension and other postretirement benefit liabilities	**(737)**	(110)	**(788)**	(523)
Net amount recognized	**$ (136)**	$1,405	**$ (807)**	$ (504)
Significant assumptions used to determine benefit obligations as of December 31:				
Discount rate	**6.60%**	6.60%	**6.60%**	6.50%
Weighted average rate of increase for compensation	**4.79%**	4.79%	**4.78%**	4.70%

(1) Represents split-dollar life insurance liability resulting from the adoption of EITF 06-4, Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements, on January 1, 2008. EITF 06-4 requires an employer to recognize a liability for future obligations (employee benefits) related to its endorsement split-dollar life insurance plans where benefits extend into postretirement periods.

(2) Represents pension plan assets of $99 million and other postretirement benefit plan obligations of $21 million at December 31, 2008 reclassified as assets held for sale and liabilities held for sale, respectively, in our Consolidated Balance Sheets in connection with the pending sale of Peoples and Hope to BBIFNA. See Note 5 for additional information.

The accumulated benefit obligation (ABO) for all of our defined benefit pension plans was $3.4 billion and $3.2 billion at December 31, 2008 and 2007, 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. No contributions to our pension plans are currently expected in 2009.

We do not expect any pension or other postretirement benefit plan assets to be returned to the Company during 2009.

The following table provides information on the benefit obligation and fair value of plan assets for plans with a benefit obligation in excess of plan assets:

	Pension Benefits		Other Postretirement Benefits	
As of December 31,	**2008**	2007	**2008**	2007
(millions)				
Benefit obligation	**$3,320**	$139	**$1,546**	$1,328
Fair value of plan assets	**2,577**	—	**737**	803

The following table provides information on the ABO and fair value of plan assets for pension plans with an ABO in excess of plan assets:

As of December 31,	**2008**	2007
(millions)		
Accumulated benefit obligation	**$2,881**	$84
Fair value of plan assets	**2,577**	—

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

	Pension Benefits	Other Postretirement Benefits
(millions)		
2009	**$ 183**	**$ 88**
2010	**200**	**96**
2011	**199**	**104**
2012	**214**	**111**
2013	**226**	**117**
2014-2018	**1,479**	**674**

The above benefit payments for other postretirement benefit plans are expected to be offset by Medicare Part D subsidies of approximately $5 million in 2009, $6 million annually for the period 2010 through 2012, $7 million in 2013 and $43 million during the period 2014 through 2018.

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 funds is 34% U.S. equity securities, 12% non-U.S. equity securities, 22% debt securities, 7% real estate and 25% other, such as private equity investments.

Strategic investment policies are established for each of our prefunded benefit plans based upon periodic asset/liability studies. Factors considered in setting the investment policy include employee demographics, liability growth rates, future discount rates, the funded status of the plans and the expected long-term rate of return on plan assets. Deviations from the plans' strategic allocation are a function of our assessments regarding short-term risk and reward opportunities in the capital markets and/or short-term market movements which result in the plans' actual asset allocations varying from the strategic target asset allocations. Through periodic rebalancing, actual allocations are brought back in line with the target. 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			
As of December 31,	**2008**		2007		**2008**		2007	
	Fair Value	% of Total	Fair Value	% of Total	Fair Value	% of Total	Fair Value	% of Total
(millions, except percentages)								
Equity securities:								
U.S.	**$ 909**	**24%**	$1,767	35%	**$237**	**32%**	$384	40%
International	**491**	**13**	757	15	**83**	**11**	107	11
Debt securities	**1,088**	**29**	1,228	24	**304**	**41**	347	36
Real estate	**359**	**10**	406	8	**28**	**3**	31	3
Other	**910**	**24**	940	18	**95**	**13**	91	10
Total	**$3,757**	**100%**	$5,098	100%	**$747**	**100%**	$960	100%

The components of the provision for net periodic benefit (credit) cost, other comprehensive income, and regulatory assets and regulatory liabilities were as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2008**	2007	2006	**2008**	2007	2006
(millions, except percentages)						
Service cost	**$ 102**	$ 112	$ 124	**$ 60**	$ 55	$ 72
Interest cost	**236**	222	210	**93**	77	81
Expected return on plan assets	**(411)**	(391)	(357)	**(73)**	(71)	(62)
Amortization of prior service (credit) cost	**4**	4	4	**(6)**	(6)	(4)
Amortization of transition obligation	**—**	—	—	**—**	3	3
Amortization of net actuarial loss	**7**	37	89	**8**	6	24
Settlements and curtailments(1)	**—**	11	12	**—**	(3)	—
Plan amendments(2)	**—**	4	—	**1**	9	—
Net periodic benefit (credit) cost	**$ (62)**	$ (1)	$ 82	**$ 83**	$ 70	$ 114
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and regulatory liabilities:						
Current year net actuarial (gain) loss	**$1,643**	$(209)	$ —	**$ 306**	$ 137	$ —
Prior service (credit) cost	**4**	3	—	**(7)**	(8)	—
Transition asset	**—**	—	—	**—**	(17)	—
Settlements and curtailments	**—**	(21)	—	**(11)**	—	—
Less amounts included in net periodic benefit (credit) cost:						
Amortization of net actuarial loss	**(7)**	(37)	—	**(8)**	(6)	—
Amortization of prior service credit (cost)	**(4)**	(4)	—	**6**	6	—
Amortization of transition obligation	**—**	—	—	**—**	(3)	—
Plan amendments	**—**	—	—	**—**	(2)	—
Change in additional minimum liability	**—**	—	(17)	**—**	—	—
Total recognized in other comprehensive income and regulatory assets and regulatory liabilities	**$1,636**	$(268)	$ (17)	**$ 286**	$ 107	$ —
Significant assumptions used to determine periodic cost:						
Discount rate	**6.60%**	6.20%	5.60%	**6.50%**	6.10%	5.50%
Expected long-term rate of return on plan assets	**8.50%**	8.75%	8.75%	**7.75%**	8.00%	8.00%
Weighted average rate of increase for compensation	**4.79%**	4.79%	4.70%	**4.70%**	4.70%	4.70%
Healthcare cost trend rate(3)				**9.00%**	9.00%	9.00%

(1) Relates to the sale of our non-Appalachian E&P operations and the planned sale of Peoples and Hope for 2007 and 2006, respectively, and the impact of distributions to retired executives.
(2) Represents a one-time benefit enhancement for certain employees in connection with the disposition of our non-Appalachian E&P business.
(3) The healthcare cost trend rate is assumed to gradually decrease to 4.90% by 2059 and continue at that rate for years thereafter.

The components of AOCI and regulatory assets and regulatory liabilities that have not been recognized as components of periodic benefit (credit) cost are as follows:

	Pension Benefits		Other Postretirement Benefits	
As of December 31,	**2008**	2007	**2008**	2007
(millions)				
Net actuarial loss	**$2,001**	$365	**$472**	$185
Prior service (credit) cost	**23**	23	**(41)**	(40)
Total[1]	**$2,024**	$388	**$431**	$145

(1) As of December 31, 2008, of the $2 billion and $431 million related to pension benefits and other postretirement benefits, respectively, $1.1 billion and $228 million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities. As of December 31, 2007, of the $388 million and $145 million related to pension benefits and other postretirement benefits, respectively, $183 million and $116 million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities.

The following table provides the components of AOCI, regulatory assets and regulatory liabilities as of December 31, 2008 that are expected to be amortized as components of periodic benefit cost in 2009:

	Pension Benefits	Other Postretirement Benefits
(millions)		
Net actuarial loss	**$38**	**$30**
Prior service (credit) cost	**4**	**(7)**

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, asset volatilities and correlations;
- 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.

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 determine discount rates from analyses of AA/Aa rated bonds with cash flows matching the expected payments to be made under our plans.

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:

	Other Postretirement Benefits	
	One percentage point increase	One percentage point decrease
(millions)		
Effect on total service and interest cost components for 2008	**$ 23**	**$ (20)**
Effect on other postretirement benefit obligation at December 31, 2008	**194**	**(150)**

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 other postretirement benefit costs through Voluntary Employees' Beneficiary Associations (VEBAs). Our remaining subsidiaries do not prefund other postretirement benefit costs but instead pay claims as presented. We expect to contribute $62 million to the Dominion VEBAs in 2009.

In addition, we sponsor defined contribution thrift-type savings plans. During 2008, 2007 and 2006, we recognized $39 million, $37 million and $36 million, respectively, as contributions to these plans.

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. The ultimate outcome of such proceedings cannot be predicted at this time, however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on our financial position, liquidity or results of operations.

Long-Term Purchase Agreements

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

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

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

Lease Commitments

We lease various facilities, vehicles and equipment primarily under operating leases. Payments under certain leases are escalated based on an index such as the consumer price index. Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2008 are as follows:

	2009	2010	2011	2012	2013	Thereafter	Total
(millions)	**$121**	**$111**	**$100**	**$91**	**$74**	**$138**	**$635**

Rental expense totaled $160 million, $185 million and $178 million for 2008, 2007 and 2006, respectively, the majority of which is reflected in other operations and maintenance expense.

We lease the Fairless power station, 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.

Wind Farm Power Projects

NedPower Mt. Storm

In December 2006, we acquired a 50% interest in a joint venture with Shell to develop NedPower. NedPower consists of two phases totaling 264 Mw. The first (164 Mw) and second (100 Mw) phases began commercial operations in July and December 2008, respectively. As of December 2008, we have contributed $136 million to NedPower for both phases of the project.

Fowler Ridge

In January 2008, we acquired a 50% interest in a joint venture with BP to develop Fowler Ridge. The facility is expected to be built in two phases and generate a total of 650 Mw. We have committed to contribute approximately $340 million, including our initial investment and funding for the development of Phase 1. As of December 2008, we have made cash contributions of $285 million to the Phase 1 project (300 Mw). We are currently in discussions with BP regarding development of the final 350 Mw phase. Our ultimate funding requirements may decrease to the extent that the joint venture obtains non-recourse construction and term financing in 2009. We have a long-term agreement with the joint venture to purchase 200 Mw of energy, capacity and renewable attributes from Phase 1.

Environmental Matters

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

Superfund Sites

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

Manufactured Gas Sites

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. One of the former sites is conducting a state-approved post closure groundwater monitoring program and an environmental land use restriction has been recorded. At another site we have been accepted into a state-based voluntary remediation program and have not yet estimated the future remediation costs. It is not known to what degree the other former 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 NRC requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Our 2008 calculation for the NRC minimum financial assurance amount, aggregated for our nuclear units, was $2.7 billion and has been satisfied by a combination of the funds being collected and deposited in the nuclear decommissioning trusts and the real annual rate of return growth of the funds allowed by the NRC. While the current economic downturn has resulted in a decrease in the value of investments held by our nuclear decommissioning trusts, we believe that the amounts currently available in our decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units. We also believe that the decommissioning funds for the Surry and North Anna units will be sufficient, particularly when combined with ratepayer collections and contributions to these decommissioning trusts, if such future collections and contributions are required. We will continue to monitor our nuclear decommissioning trusts to ensure they meet the minimum financial assurance requirement, which may include the use of parent company guarantees, surety bonding or other financial guarantees recognized by the NRC.

Nuclear Insurance

The Price-Anderson Act provides the public up to $12.5 billion of liability protection per nuclear incident via obligations required of owners of nuclear power plants. The Price-Anderson Act Amendment of 1988 allows for an inflationary provision adjustment every five years. We have purchased $300 million of coverage from commercial insurance pools for each reactor site with the remainder provided through a mandatory industry risk-sharing program. In the event of a nuclear incident at any licensed nuclear reactor in the U.S., we could be assessed up to $118 million for each of our seven licensed reactors not to exceed $18 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. The Price-Anderson Act was first enacted in 1957 and was renewed again in 2005.

Our current level of property insurance coverage ($2.55 billion for North Anna, $2.55 billion for Surry, $2.75 billion for Millstone, and $1.8 billion for Kewaunee) exceeds the NRC 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 $97 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 $34 million.

ODEC, a part owner of North Anna, and Massachusetts Municipal Wholesale Electric Company and Central Vermont Public Service Corporation, part owners of Millstone's Unit 3, are responsible to us 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 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 lawsuits in the U.S. Court of Federal Claims against the DOE requesting damages in connection with its failure to commence accepting spent nuclear fuel. A trial occurred in May 2008 and post-trial briefing and argument concluded in July 2008. On October 15, 2008, the Court issued an opinion and order for us in the amount of approximately $155 million for our spent fuel-related costs through June 30, 2006, and judgment was entered by the Court on October 28, 2008. On December 24, 2008, the government appealed the judgment to the U. S. Court of Appeals for the Federal Circuit and the appeal was docketed on December 30, 2008. Briefing on the appeal is expected to take place in 2009. Payment of any damages will not occur until the appeal process has been resolved. We cannot predict the outcome of this matter; however, in the event that we recover damages, such recovery, including amounts attributable to joint owners, is not expected to have a material impact on our results of operations. We will continue to manage our spent fuel until it is accepted by the DOE.

Guarantees, Surety Bonds and Letters of Credit

At December 31, 2008, we had issued $419 million of guarantees to support third parties and equity method investees (issued guarantees). This includes $196 million of guarantees to support our investment in a joint venture with Shell to develop NedPower. These NedPower guarantees are primarily comprised of a limited-scope guarantee and indemnification for one-half of the project-level financing for phases one and two of the NedPower wind farm, which would require us to pay one-half of NedPower's debt, only if it is unable to do so, as a direct result of an unfavorable ruling associated with current litigation seeking to halt the project. This litigation-related guarantee will terminate when a final non-appealable ruling in favor of the project is received. We do not expect an unfavorable ruling and no significant amounts have been recorded. Our exposure under this litigation-related guarantee totaled $166 million as of December 31, 2008. Shell has provided an identical guarantee for the other one-half of NedPower's borrowings.

Issued guarantees also include $163 million of guarantees to support our investment in a joint venture with BP to develop Fowler Ridge. The guarantees primarily relate to payments for wind turbines and construction costs. Our exposure under these guarantees was $36 million as of December 31, 2008 and will largely decline during 2009, as the joint venture makes the underlying payments covered by these guarantees. BP has provided identical guarantees for the other one-half of these joint venture commitments.

We also enter into guarantee arrangements on behalf of our consolidated subsidiaries, primarily to facilitate their commercial transactions with third parties. To the extent that a liability subject to a guarantee has been incurred by one of our consolidated subsidiaries, that liability is included in our Consolidated Financial Statements. We are not required to recognize liabilities for guarantees issued on behalf of our subsidiaries unless it becomes probable that we will have to perform under the guarantees. We believe it is unlikely that we would be required to perform or otherwise incur any losses associated with guarantees of our subsidiaries' obligations.

At December 31, 2008, we had issued the following subsidiary guarantees:

	Stated Limit	Value(1)
(millions)		
Subsidiary debt(2)	$ 75	$ 75
Commodity transactions(3)	3,052	283
Lease obligation for power generation facility(4)	864	864
Nuclear obligations(5)	413	302
Cove Point LNG facility(6)	770	701
Other	262	162
Total	$5,436	$2,387

(1) *Represents the estimated portion of the guarantee's stated limit that is utilized as of December 31, 2008 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 certain DEI subsidiaries. In the event of default by the subsidiaries, we would be obligated to repay such amounts.*
(3) *Guarantees related to energy trading and marketing activities and other commodity commitments of certain subsidiaries, including subsidiaries of Virginia Power and DEI. These guarantees were provided to counterparties in order to facilitate physical and financial transactions in gas, oil, electricity, pipeline capacity, transportation and related commodities and services. If 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 Fairless.*
(5) *Guarantees related to certain DEI subsidiaries' potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and guarantees for a DEI subsidiary's and Virginia Power's commitment to buy nuclear fuel. Excludes our agreement to provide up to $150 million and $60 million to two DEI subsidiaries, to pay the operating expenses of Millstone and Kewaunee, respectively, in the event of a prolonged outage, as part of satisfying certain NRC requirements concerned with ensuring adequate funding for the operations of nuclear power stations.*
(6) *Includes a $700 million payment and performance guarantee related to the expansion of our Cove Point LNG facility.*

Additionally, as of December 31, 2008, we had purchased $166 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $312 million 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, 2008, we believe future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

We have entered into other types of contracts that require indemnifications, such as purchase and sale agreements and financing agreements. These agreements may include, but are not limited to, indemnifications around certain title, tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price and is typically limited in duration depending on the nature of the indemnified matter. Since January 1, 2005, we have entered into sale agreements with maximum exposure related to the collective purchase prices of approximately $16 billion. We do not expect that we would be required to perform under these indemnifications and have not recognized any significant liabilities related to these arrangements.

Status of Electric Regulation in Virginia

2007 Virginia Regulation Act and Fuel Factor Amendments

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

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

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

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

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

Virginia Fuel Expenses

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

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

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

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

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

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

North Carolina Regulation

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

Dominion Transmission Rates

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

In December 2007, DTI and the Independent Oil and Gas Association of West Virginia, Inc. reached a settlement agreement on DTI's gathering and processing rates for the period January 1, 2009 through December 31, 2011. This settlement maintains the gas retainage fee structure that DTI has had since 2001. Under the settlement, the gathering retainage rate increases from 9.25% to 10.5% and the processing retainage rate—in recognition of the increased market value of natural gas liquids—decreases from 3.25% to 0.5%.

This reduction in the combined retainage, from 12.5% to 11%, should provide a lower overall cost for most producers. Due to the increase in natural gas prices from three years ago, the consolidated impact of these rate changes is expected to increase DTI's gathering and processing revenues. In addition, DTI will continue to retain all revenues from its liquids sales, thus maintaining its cash flow from this activity.

In connection with the settlement, DTI also agreed to invest at least $20 million annually in Appalachian gathering-related assets. The new rates have been approved by FERC as negotiated rates.

Litigation

Gas and Oil Operations

In 2006, Gary P. Jones and others filed suit against DTI, DEPI and DRS. The plaintiffs are royalty owners, seeking to recover damages as a result of the Dominion defendants allegedly underpaying royalties by improperly deducting post-production costs and not paying fair market value for the gas produced from their leases. The plaintiffs seek class action status on behalf of all West Virginia residents and others who are parties to, or beneficiaries of, oil and gas leases with the Dominion defendants. DRS is erroneously named as a defendant, as the parent company of DTI and DEPI. During 2007, we established a litigation reserve representing our best estimate of the probable loss related to this matter. We do not believe that the final resolution of this matter will have a material adverse effect on our results of operations or financial condition. By order dated July 16, 2008, the Court preliminarily approved settlement of the class action and conditionally certified a temporary settlement class. The Court also dismissed DRS and added Dominion Appalachian Development LLC as a defendant for the sole purpose of settling the class claims. Following preliminary approval by the Court, settlement notices were sent out to potential class members. In 2009, the Court entered a Memorandum Opinion and Final Order approving settlement and certifying the settlement class and the Final Judgment Order.

Electric Utility Operations

We are co-owners with ODEC of the Clover power station. In 1989, we entered into a long term coal transportation agreement with Norfolk Southern Railway Company (Norfolk Southern) for the delivery of coal to the facility. The agreement specifies a base rate with adjustments tied to a published index. Norfolk Southern claimed in October 2003 that the parties to the agreement had employed an incorrect reference index since the agreement's inception to adjust the base transportation rate. In November 2003, we and ODEC filed suit against Norfolk Southern seeking to clarify the price adjustment provisions of the transportation agreement. The trial court ruled in Norfolk Southern's favor by concluding that the agreement specifies the use of the index (NS Index) which Norfolk Southern claims should have been applied to adjust the base rate and which should be applied going forward. On September 1, 2006, the court entered an order directing us and ODEC to correct invoices from December 1, 2003 to the present by calculating rates using the NS Index as if it had been applied from the inception of the agreement, to tender the difference to Norfolk Southern with interest at the rate provided by the agreement and to pay future invoices using the NS Index as if it had been applied from the inception of the agreement.

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

Note 24. 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.

We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our December 31, 2008 provision for credit losses, that it is unlikely 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 primarily with major companies in the energy industry and with commercial and residential energy consumers. These transactions principally occur in the Northeast, mid-Atlantic and Midwest regions of the U.S. and Texas. We do not believe that this geographic concentration contributes significantly to our overall exposure to credit risk. In addition, as a result of our large and diverse customer base, we are not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations, including transmission services and retail energy sales.

Our exposure to credit risk is concentrated primarily within our energy marketing and price risk management activities, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include trading of energy-related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. Gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At December 31, 2008, our gross credit exposure totaled $1.6 billion. After the application of collateral, our credit exposure is reduced to $1.2 billion. Of this amount, investment grade counterparties, including those internally rated, represented 97% and no single counterparty exceeded 21%.

NOTE 25. DOMINION CAPITAL, INC.

Our Consolidated Balance Sheets reflect the following DCI assets:

At December 31,	2008	2007
(millions)		
Current assets(1)	$ 7	$266
Loans held for resale	—	323
Loans receivable, net	35	34
Other investments	41	72
Deferred charges and other assets(2)	127	127
Total	$210	$822

(1) Includes $30 million of loans held for resale in 2007.
(2) Primarily reflects deferred tax assets.

At December 31, 2007, DCI held an investment in the subordinated notes of a third-party CDO entity. The CDO entity's primary focus is the purchase and origination of middle market senior secured first and second lien commercial and industrial loans in both the primary and secondary loan markets. We concluded previously that the CDO entity was a VIE and that DCI was the primary beneficiary of the CDO entity and therefore we consolidated the CDO entity in accordance with FIN 46R at December 31, 2007. Due to the consolidation of the CDO entity at December 31, 2007, our consolidated balance sheet included $460 million of notes payable, which were nonrecourse to us, and the following assets that served as collateral for its obligations:

As of December 31,	2007
(millions)	
Other current assets(1)	$257
Loans held for resale	323
Other investments	32
Total assets	$612

(1) Includes $30 million of loans held for resale.

In March 2008, we reached an agreement to sell our remaining interest in the subordinated notes effectively eliminating the variability of our interest, and therefore deconsolidated the CDO entity as of March 31, 2008 and recognized impairment losses of $62 million ($38 million after-tax). In connection with the sale of the subordinated notes, in April 2008, we received proceeds of $54 million, including accrued interest. This sale concluded our efforts to divest of DCI, since its remaining assets are aligned with our core business.

Impairment Losses

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

Year Ended December 31,	2008	2007	2006
(millions)			
Retained interests from CMO securitizations(1)	$—	$27	$—
Loans held for resale(2)	—	54	—
Retained interests from CDO securitizations	62(3)	—	85(1)
Venture capital and other equity investments(3)	—	17	6
Total	$62	$98	$91

(1) Reflects the 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 collateralized mortgage obligations (CMO) securitizations in 2007 and retained interests from CDO securitizations in 2008 and 2006. We updated our credit loss and prepayment assumptions to reflect our recent experience.
(2) During 2007, we recorded LOCOM adjustments of $54 million on our loans held for resale.
(3) Impairments were recorded primarily due to our decision to dispose of the assets when it became probable we would not recover the assets' recorded basis.

NOTE 26. OPERATING SEGMENTS

We are organized primarily on the basis of products and services sold in the U.S. A description of our segments follows:

DVP includes our regulated electric transmission, distribution and customer service operations, as well as our nonregulated retail energy marketing operations.

Dominion Energy includes our Ohio regulated natural gas distribution company, regulated gas transmission pipeline and storage operations, including gathering and extraction activities, regulated LNG operations and our remaining E&P operations. Dominion Energy also includes producer services, which aggregates natural gas supply, engages in natural gas trading and marketing activities and natural gas supply management and provides price risk management services to Dominion affiliates.

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

Corporate and Other includes our corporate, service company, corporate-wide enterprise commodity risk management services and other functions (including unallocated debt). In addition, this segment includes the remaining assets and operations of DCI, the net impact of discontinued operations, our non-Appalachian natural gas and oil E&P operations that were sold and our regulated gas distribution subsidiaries that are held for sale. 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 segments' performance or allocating resources among the segments and are instead reported in the Corporate and Other segment. In 2008, we reported net expenses of $137 million in the Corporate and Other segment attributable to our operating segments. The net expenses in 2008 primarily related to the impact of the following items attributable to Dominion Generation:

- $180 million ($109 million after-tax) of certain impairment charges reflecting other-than-temporary declines in the fair value of securities held as investments in our nuclear decommissioning trusts as of December 31, 2008; and
- $39 million ($24 million after-tax) of impairment charges related to non-refundable deposits for certain generation-related vendor contracts.

In 2007, we reported net expenses of $618 million in the Corporate and Other segment attributable to our operating segments. The net expenses in 2007 primarily related to the impact of the following items attributable to Dominion Generation:

- A $387 million ($252 million after-tax) charge related to the impairment of Dresden;
- A $259 million ($158 million after-tax) extraordinary charge due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations; and
- A $231 million ($137 million after-tax) charge resulting from the termination of the long-term power sales agreement associated with State Line.

In 2006, we reported net expenses of $10 million in the Corporate and Other segment attributable to our operating segments. The net expenses in 2006 primarily related to the impact of the following:

- A $21 million tax benefit from the partial reduction of previously recorded valuation allowances on certain federal and state tax loss carryforwards (attributable to Dominion Generation), since these carryforwards were expected to be utilized to offset capital gain income that would have been generated from the planned sale of Peoples and Hope;
- A $27 million ($17 million after-tax) charge resulting from the cancellation of a pipeline project, attributable to Dominion Energy; and
- A $26 million impairment ($15 million after-tax) charge resulting from a change in our method of assessing other-than-temporary declines in the fair value of securities held as investments in our nuclear decommissioning trusts, attributable to Dominion Generation.

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

The following table presents segment information pertaining to our operations:

Year Ended December 31,	DVP	Dominion Energy	Dominion Generation	Corporate and Other	Adjustments & Eliminations	Consolidated Total
(millions)						
2008						
Total revenue from external customers	**$2,977**	**$2,450**	**$8,569**	**$ 704**	**$ 1,590**	**$16,290**
Intersegment revenue	**134**	**1,862**	**102**	**732**	**(2,830)**	**—**
Total operating revenue	**3,111**	**4,312**	**8,671**	**1,436**	**(1,240)**	**16,290**
Depreciation, depletion and amortization	**312**	**277**	**423**	**24**	**(2)**	**1,034**
Equity in earnings of equity method investees	**—**	**17**	**27**	**8**	**—**	**52**
Interest income	**22**	**35**	**78**	**116**	**(163)**	**88**
Interest and related charges	**157**	**136**	**238**	**485**	**(163)**	**853**
Income taxes	**232**	**281**	**688**	**(322)**	**—**	**879**
Loss from discontinued operations, net of tax	**—**	**—**	**—**	**(2)**	**—**	**(2)**
Net income (loss)	**380**	**468**	**1,227**	**(241)**	**—**	**1,834**
Investment in equity method investees	**6**	**114**	**557**	**49**	**—**	**726**
Capital expenditures	**797**	**929**	**1,665**	**163**	**—**	**3,554**
Total assets (billions)	**9.4**	**11.1**	**19.2**	**15.3**	**(12.9)**	**42.1**
2007(1)						
Total revenue from external customers	$2,804	$1,993	$7,630	$1,208	$ 1,181	$14,816
Intersegment revenue	151	1,525	135	596	(2,407)	—
Total operating revenue	2,955	3,518	7,765	1,804	(1,226)	14,816
Depreciation, depletion and amortization	300	243	363	465	(3)	1,368
Equity in earnings of equity method investees	1	13	15	6	—	35
Interest income	14	32	67	172	(140)	145
Interest and related charges	147	109	264	797	(140)	1,177
Income taxes	263	241	494	785	—	1,783
Loss from discontinued operations, net of tax	—	—	—	(8)	—	(8)
Extraordinary item, net of tax	—	—	—	(158)	—	(158)
Net income	415	387	756	981	—	2,539
Investment in equity method investees	6	97	181	47	—	331
Capital expenditures	564	937	1,026	1,445	—	3,972
Total assets (billions)	8.4	9.4	16.9	13.6	(9.2)	39.1
2006(1)						
Total revenue from external customers	$2,544	$2,968	$7,051	$3,778	$ 935	$17,276
Intersegment revenue	76	1,218	137	621	(2,052)	—
Total operating revenue	2,620	4,186	7,188	4,399	(1,117)	17,276
Depreciation, depletion and amortization	294	197	311	758	(3)	1,557
Equity in earnings of equity method investees	1	12	18	6	—	37
Interest income	11	26	65	100	(87)	115
Interest and related charges	143	118	259	655	(87)	1,088
Income taxes	263	232	351	81	—	927
Loss from discontinued operations, net of tax	—	—	—	(150)	—	(150)
Net income	411	347	537	85	—	1,380
Capital expenditures	523	493	1,018	2,018	—	4,052

(1) In the fourth quarter of 2008, we revised our derivative income statement classification policy to present income statement activity for all non-trading derivatives based on the nature of the underlying risk as discussed in Note 2 to our Consolidated Financial Statements. Prior periods have been recast to conform to this presentation.

At December 31, 2008 and 2007, none of our long-lived assets and no significant percentage of our operating revenues were associated with international operations. For the year ended December 31, 2006, approximately 1% of our operating revenues were associated with international operations.

Note 27. 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 depletion follow:

At December 31,	**2008**	2007
(millions)		
Capitalized costs:		
Proved properties	**$1,727**	$1,789
Unproved properties	**11**	10
Total capitalized costs	**1,738**	1,799
Accumulated depletion:		
Proved properties	**394**	104
Unproved properties	**—**	—
Total accumulated depletion	**394**	104
Net capitalized costs	**$1,344**	$1,695

Total Costs Incurred

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

Year Ended December 31,			**2008**			2007			2006
	Total	**U.S.**	**Canada**	Total	U.S.	Canada	Total	U.S.	Canada
(millions)									
Property acquisition costs:									
Proved properties	**$ 2**	**$ 2**	**$—**	$ 19	$ 19	$—	$ 87	$ 87	$ —
Unproved properties	**4**	**4**	**—**	77	75	2	171	165	6
Total property acquisition costs	**6**	**6**	**—**	96	94	2	258	252	6
Exploration costs	**1**	**1**	**—**	132	126	6	399	383	16
Development costs[1]	**205**	**205**	**—**	1,114	1,086	28	1,451	1,365	86
Total	**$212**	**$212**	**$—**	$1,342	$1,306	$36	$2,108	$2,000	$108

(1) Development costs incurred for proved undeveloped reserves were $80 million, $445 million and $302 million for 2008, 2007 and 2006, respectively.

Results of Operations

We caution that the following standard 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,			**2008**			2007			2006
	Total	**U.S.**	**Canada**	Total	U.S.	Canada	Total	U.S.	Canada
(millions)									
Revenue (net of royalties) from:									
Sales to nonaffiliated companies	**$162**	**$162**	**$—**	$1,367	$1,291	$76	$1,883	$1,749	$134
Transfers to other operations	**363**	**363**	**—**	298	298	—	253	253	—
Total	**525**	**525**	**—**	1,665	1,589	76	2,136	2,002	134
Less:			**—**						
Production (lifting) costs	**64**	**64**	**—**	396	369	27	552	510	42
Depreciation, depletion and amortization	**129**	**129**	**—**	536	514	22	801	750	51
Income tax expense	**136**	**136**	**—**	271	262	9	285	271	14
Results of operations	**$196**	**$196**	**$—**	$ 462	$ 444	$18	$ 498	$ 471	$ 27

Company-Owned Reserves

Estimated net quantities of proved gas and oil (including condensate) reserves in the U.S. and Canada at December 31, 2008, 2007 and 2006, and changes in the reserves during those years, are shown in the two schedules that follow:

		2008			2007			2006	
	Total	**U.S.**	**Canada**	Total	U.S.	Canada	Total	U.S.	Canada
(bcf)									
Proved developed and undeveloped reserves—Gas									
At January 1	**1,019**	**1,019**	**—**	5,136	4,961	175	4,962	4,856	106
Changes in reserves:									
Extensions, discoveries and other additions	**46**	**46**	**—**	139	130	9	431	393	38
Revisions of previous estimates	**93**	**93**	**—**	88	88	—	109	58	51
Production	**(59)**	**(59)**	**—**	(214)	(206)	(8)	(318)	(302)	(16)
Purchases of gas in place	**—**	**—**	**—**	44	44	—	48	48	—
Sales of gas in place	**—**	**—**	**—**	(4,174)	(3,998)	(176)	(96)	(92)	(4)
At December 31	**1,099**	**1,099**	**—**	1,019	1,019	—	5,136	4,961	175
Proved developed reserves—Gas									
At January 1	**636**	**636**	**—**	3,556	3,424	132	3,706	3,605	101
At December 31	**672**	**672**	**—**	636	636	—	3,556	3,424	132
Proved developed and undeveloped reserves—Oil (thousands of barrels)									
At January 1	**12,613**	**12,613**	**—**	232,259	216,849	15,410	217,698	198,602	19,096
Changes in reserves:									
Extensions, discoveries and other additions	**484**	**484**	**—**	3,094	2,853	241	11,373	10,678	695
Revisions of previous estimates(1)	**256**	**256**	**—**	932	932	—	38,010	40,629	(2,619)
Production	**(919)**	**(919)**	**—**	(12,185)	(11,626)	(559)	(24,947)	(23,923)	(1,024)
Purchases of oil in place	**—**	**—**	**—**	3	3	—	615	615	—
Sales of oil in place	**—**	**—**	**—**	(211,490)	(196,398)	(15,092)	(10,490)	(9,752)	(738)
At December 31(2)	**12,434**	**12,434**	**—**	12,613	12,613	—	232,259	216,849	15,410
Proved developed reserves—Oil									
At January 1	**12,613**	**12,613**	**—**	180,779	173,718	7,061	152,889	145,735	7,154
At December 31	**12,406**	**12,406**	**—**	12,613	12,613	—	180,779	173,718	7,061

(1) The decrease in the U.S. revision in 2007 is primarily attributable to the sale of our non-Appalachian E&P operations. The 2006 U.S. revision is comprised of approximately 27.6 million barrels of natural gas liquids and 13 million barrels of oil/condensate. Natural gas liquids revisions were primarily the result of additional contractual changes with third-party gas processors in which we now take title to our processed natural gas liquids, and residue gas and liquids reserve amounts recognized under such contracts. Oil/condensate revisions were primarily the result of positive performance revisions at Gulf of Mexico deep-water locations.

(2) Ending reserves for 2008, 2007 and 2006 included 1.0 million, 0.3 million and 114.6 million barrels of oil/condensate, respectively, and 11.4 million, 12.3 million and 117.7 million barrels of natural gas liquids, respectively.

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:

		2008			2007			2006	
	Total	**U.S.**	**Canada**	Total	U.S.	Canada	Total	U.S.	Canada
(millions)									
Future cash inflows(1)	**$7,360**	**$7,360**	**$—**	$8,128	$8,128	$—	$38,326	$36,604	$1,722
Less:									
Future development costs(2)	**920**	**920**	**—**	671	671	—	3,226	3,052	174
Future production costs	**1,293**	**1,293**	**—**	1,235	1,235	—	7,421	6,936	485
Future income tax expense	**2,010**	**2,010**	**—**	2,432	2,432	—	9,112	8,782	330
Future cash flows	**3,137**	**3,137**	**—**	3,790	3,790	—	18,567	17,834	733
Less annual discount (10% a year)	**2,029**	**2,029**	**—**	2,346	2,346	—	10,458	10,143	315
Standardized measure of discounted future net cash flows	**$1,108**	**$1,108**	**$—**	$1,444	$1,444	$—	$ 8,109	$ 7,691	$ 418

(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 $223 million, $109 million and $107 million for 2009, 2010 and 2011, respectively.

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)	**2008**	2007	2006
Standardized measure of discounted future net cash flows at January 1	**$1,444**	$ 8,109	$ 14,963
Changes in the year resulting from:			
Sales and transfers of gas and oil produced during the year, less production costs	**(460)**	(1,270)	(2,791)
Prices and production and development costs related to future production	**(721)**	289	(11,788)
Extensions, discoveries and other additions, less production and development costs	**129**	419	758
Previously estimated development costs incurred during the year	**67**	467	302
Revisions of previous quantity estimates	**171**	286	409
Accretion of discount	**236**	181	2,327
Income taxes	**119**	3,173	4,352
Other purchases and sales of proved reserves in place	**—**	(10,197)	(346)
Other (principally timing of production)	**123**	(13)	(77)
Standardized measure of discounted future net cash flows at December 31	**$1,108**	$ 1,444	$ 8,109

Note 28. Quarterly Financial and Common Stock Data (Unaudited)

A summary of our quarterly results of operations for the years ended December 31, 2008 and 2007 follows. Amounts reflect all adjustments necessary in the opinion of management for a fair statement of the results for the interim periods. Results for interim periods may fluctuate as a result of weather conditions, changes in rates and other factors. As discussed in Note 2, in the fourth quarter of 2008, we revised our derivative income statement classification policy to present income statement activity for all non-trading derivatives based on the nature of the underlying risk. Prior quarters for 2008 and 2007 have been recast to conform to this presentation. All differences between amounts presented below and those previously reported in our Quarterly Reports on Forms 10-Q during 2008 and 2007 are a result of the change in our derivative income statement classification policy.

(millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
2008					
Operating revenue as previously reported	**$ 4,389**	**$ 3,452**	**$ 4,231**	**$ 4,173**	**$16,245**
Operating revenue as recast	**4,353**	**3,399**	**4,365**	**4,173**	**16,290**
Income from operations	**1,059**	**711**	**1,055**	**801**	**3,626**
Income from continuing operations	**680**	**300**	**508**	**348**	**1,836**
Loss from discontinued operations	**—**	**(2)**	**—**	**—**	**(2)**
Net income	**680**	**298**	**508**	**348**	**1,834**
Basic EPS:					
Income from continuing operations	**1.18**	**0.52**	**0.88**	**0.60**	**3.17**
Income from discontinued operations	**—**	**—**	**—**	**—**	**—**
Net income	**1.18**	**0.52**	**0.88**	**0.60**	**3.17**
Diluted EPS:					
Income from continuing operations	**1.18**	**0.51**	**0.87**	**0.60**	**3.16**
Income from discontinued operations	**—**	**—**	**—**	**—**	**—**
Net income	**1.18**	**0.51**	**0.87**	**0.60**	**3.16**
Dividends paid per share	**0.395**	**0.395**	**0.395**	**0.395**	**1.58**
Common stock prices (high-low)	**$48.50 - 38.63**	**$48.28 - 41.12**	**$48.50 - 40.51**	**$44.46 - 31.26**	**$48.50 - 31.26**
2007					
Operating revenue as previously reported	$ 4,661	$ 3,730	$ 3,589	$ 3,694	$15,674
Operating revenue as recast	4,655	3,097	3,417	3,647	14,816
Income (loss) from operations as previously reported	1,000	(380)	4,215	732	5,567
Income (loss) from operations as recast	1,000	(405)	4,241	733	5,569
Income (loss) from continuing operations	475	(392)	2,320	302	2,705
Income (loss) from discontinued operations	(22)	20	(3)	(3)	(8)
Extraordinary item, net of tax	—	(158)	—	—	(158)
Net income (loss)	453	(530)	2,317	299	2,539
Basic EPS:					
Income (loss) from continuing operations	0.68	(0.56)	3.65	0.53	4.15
Income (loss) from discontinued operations	(0.03)	0.03	(0.01)	(0.01)	(0.01)
Extraordinary item, net of tax	—	(0.23)	—	—	(0.24)
Net income (loss)	0.65	(0.76)	3.64	0.52	3.90
Diluted EPS:					
Income (loss) from continuing operations	0.68	(0.56)	3.63	0.53	4.13
Income (loss) from discontinued operations	(0.03)	0.03	(0.01)	(0.01)	(0.01)
Extraordinary item, net of tax	—	(0.23)	—	—	(0.24)
Net income (loss)	0.65	(0.76)	3.62	0.52	3.88
Dividends paid per share	0.355	0.355	0.355	0.395	1.46
Common stock prices (high-low)	$44.71 - 39.84	$46.82 - 40.03	$46.00 - 40.76	$49.38 - 42.23	$49.38 - 39.84

Our 2008 results include the impact of the following significant items:

- First quarter results include a $136 million after-tax benefit due to the reversal of deferred tax liabilities associated with the planned sale of Peoples and Hope. Results also include a $38 million after-tax charge resulting from the impairment of a DCI investment.
- Third quarter results include a $26 million after-tax adjustment to the gain from the disposition of our U.S. non-Appalachian E&P operations.
- Fourth quarter results include a $24 million after-tax impairment charge related to non-refundable deposits for certain generation-related vendor contracts.

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

- Second quarter results include a $341 million after-tax charge due to the discontinuance of hedge accounting for certain gas and oil derivatives associated with the sale of our non-Appalachian E&P operations, a $252 million after-tax impairment charge associated with the sale of Dresden, a $158 million after-tax extraordinary charge due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations and a $108 million after-tax charge for the recognition of certain forward gas contracts that no longer qualified for the normal purchase and sales exemption due to the sale of our U.S. non-Appalachian E&P operations.
- Third quarter results include a $2.1 billion after-tax gain from the disposition of our U.S. non-Appalachian E&P operations. Results also include a $140 million after-tax charge related to a long-term power sales agreement at State Line that no longer qualified for the normal purchase and sales exemption due to the termination of the agreement in the fourth quarter of 2007.

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

None.

Item 9A. Controls and Procedures

Senior management, including our CEO and CFO, 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 CEO and CFO 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 2008 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, 2008, 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.

We evaluated Dominion's internal control over financial reporting as of December 31, 2008. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, we believe that Dominion maintained effective internal control over financial reporting as of December 31, 2008.

Our independent registered public accounting firm is engaged to express an opinion on our internal control over financial reporting, as stated in their report which is included herein.
February 24, 2009

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Dominion Resources, Inc.
Richmond, Virginia

We have audited the internal control over financial reporting of Dominion Resources, Inc. (the "Company") as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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, 2008 of the Company and our report dated February 24, 2009, expressed an unqualified opinion on those financial statements and includes an explanatory paragraph relating to the adoption of new accounting standards.

/s/ Deloitte & Touche LLP
Richmond, Virginia
February 24, 2009

Item 9B. Other Information

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

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

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

We also announced the following changes to the chief executive officer positions in each of our three primary operating segments, effective June 1, 2009:

Paul D. Koonce, 49, will become Chief Executive Officer of Dominion Virginia Power. He is currently the Chief Executive Officer of Dominion Energy.

David A. Christian, 54, will become Chief Executive Officer of Dominion Generation. He is currently the President and Chief Nuclear Officer of Dominion Nuclear, a unit of Dominion Generation which operates our four nuclear power stations in three states. David A. Heacock will assume Mr. Christian's responsibilities at Dominion Nuclear. Mr. Heacock is currently the President of our Dominion Virginia Power segment.

Gary L. Sypolt, 55, will become Chief Executive Officer of Dominion Energy. Mr. Sypolt is currently President of Dominion Energy.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

The following information is incorporated by reference from the 2009 Proxy Statement, File No. 001-08489, which will be filed on or around March 31, 2009 (the 2009 Proxy Statement):

- Information regarding the directors required by this item is found under the heading *Election of Directors*.
- Information regarding compliance with Section 16 of the Exchange Act required by this item is found under the heading *Section 16(a) Beneficial Ownership Reporting Compliance*.
- Information regarding Dominion's Audit Committee Financial expert(s) is found under the heading *Director Independence* and *Committees and Meeting Attendance*.
- Information regarding Dominion's Audit Committee required by this item is found under the heading *The Audit Committee Report* and *Committees and Meeting Attendance*.
- Information regarding Dominion's Code of Ethics required by this item is found under the heading *Corporate Governance and Board Matters*.

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 following information is contained in the 2009 Proxy Statement and is incorporated by reference: the information regarding executive compensation contained under the headings *Compensation Discussion and Analysis* and *Executive Compensation*; the information regarding Compensation Committee interlocks contained under the heading *Compensation Committee Interlocks and Insider Participation*; the *Compensation, Governance and Nominating Committee Report*; and the information regarding director compensation contained under the heading *Non-Employee Director Compensation*.

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 headings *Director and Officer Share Ownership* and *Significant Shareholder* in the 2009 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 2009 Proxy Statement is incorporated by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information regarding related party transactions required by this item found under the heading *Related Party Transactions*, and information regarding director independence found under the heading *Director Independence*, in the 2009 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 *Fees and Pre-Approval Policy* in the 2009 Proxy Statement is incorporated by reference.

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 53.

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

2. Exhibits

3.1 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), as amended November 9, 2007 (Exhibit 3, Form 8-K filed November 9, 2007, File No. 1-8489, incorporated by reference).

3.2 Amended and Restated Bylaws, effective June 20, 2007 (Exhibit 3.1, Form 8-K, dated June 22, 2007, 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); and Eighty-First Supplemental Indenture, (Exhibit 4(iii), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference).

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

4.4 Form of Senior Indenture, dated as of June 1, 1998, between Virginia Electric and Power Company and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by the First Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 4, 1999, File No. 1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K filed October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K filed March 26, 2001, File No. 1-2255, incorporated by reference); Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K filed March 26, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 29, 2002, File No. 1-2255, incorporated by reference); Seventh Supplemental Indenture (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Eighth Supplemental Indenture (Exhibit 4.2, Form 8-K filed February 27, 2003, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 11, 2003, File No. 1-2255, incorporated by reference); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Thirteenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Fourteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255, incorporated by reference); Form of Fifteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255, incorporated by reference); Form of Sixteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 30, 2007, File No. 1-2255, incorporated by reference); Form of Seventeenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255, incorporated by reference); Form of Eighteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed April 15, 2008, File No. 1-2255, incorporated by reference); Nineteenth Supplemental and Amending Indenture (Exhibit 4.2, Form 8-K filed November 5, 2008, File No. 1-2255, incorporated by reference).

4.5 Indenture, Junior Subordinated Debentures, dated December 1, 1997, between Dominion Resources, Inc. and The Bank of New York (as successor trustee to 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).

4.6 Indenture, dated as of May 1, 1971, between Consolidated Natural Gas Company and The Bank of New York (as successor trustee to 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); Twenty-First Supplemental Indenture dated as of June 27, 2007 (Exhibit 4.2, Form 8-K, filed July 3, 2007, File No. 1-8489, 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 (4A)(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 7⅜% 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 6⅞% 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 6⅝% 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 7¼% Notes Due October 1, 2004, incorporated by reference); Second Supplemental Indenture dated as of June 27, 2007 (Exhibit 4.4, Form 8-K, filed July 3, 2007, File No. 1-8489, incorporated by reference).

4.8 Form of Senior Indenture, dated June 1, 2000, between Dominion Resources, Inc. and The Bank of New York (as successor trustee to 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); Form of Thirty-Second Supplemental Indenture (Exhibit 4.2, Form 8-K, filed November 13, 2007, File No. 1-8489, incorporated by reference); Form of Thirty-Third Supplemental Indenture (Exhibit 4.3, Form 8-K, filed November 13, 2007, File No. 1-8489, incorporated by reference); Form of Thirty-Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K, filed November 29, 2007, File No. 1-8489, incorporated by reference); Form of Thirty-Fifth Supplemental Indenture (Exhibit 4.2, Form 8-K, filed June 16, 2008, File No. 1-8489, incorporated by reference); Form of Thirty-Sixth Supplemental Indenture (Exhibit 4.3, Form 8-K, filed June 16, 2008, File No. 1-8489, incorporated by reference); Form of Thirty-Seventh Supplemental Indenture (Exhibit 4.4, Form 8-K, filed June 16, 2008, File No. 1-8489, incorporated by reference); Form of Thirty-Eighth Supplemental and Amending Indenture (Exhibit 4.2, Form 8-K, filed November 26, 2008, File No. 1-8489, incorporated by reference); Thirty-Ninth Supplemental Indenture Amending the Twenty-Seventh Supplemental Indenture (Exhibit 4.1, Form 8-K, filed December 5, 2008, File No. 1-8489, incorporated by reference).

4.9 Indenture, dated April 1, 2001, between Consolidated Natural Gas Company and The Bank of New York (as successor trustee to 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); Seventh Supplemental Indenture dated as of June 27, 2007 (Exhibit 4.6, Form 8-K, filed July 3, 2007, File No. 1-8489, incorporated by reference).

4.10 Form of Indenture for Junior Subordinated Debentures, dated October 1, 2001, between Consolidated Natural Gas Company and The Bank of New York (as successor trustee to 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); Second Supplemental Indenture dated as of June 27, 2007 (Exhibit 4.8, Form 8-K, filed July 3, 2007, File No. 1-8489, incorporated by reference).

4.11 Junior Subordinated Indenture II, dated June 1, 2006, between Dominion Resources, Inc. and the Bank of New York (successor to JPMorgan Chase Bank, N.A.), as Trustee (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2006, File No. 1-8489, incorporated by reference), as supplemented by the First Supplemental Indenture dated as of June 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended June 30, 2006, File No. 1-8489, incorporated by reference); the Second Supplemental Indenture, dated as of September 1, 2006, (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2006, File No. 1-8489, incorporated by reference).

4.12 Replacement Capital Covenant entered into by Dominion Resources, Inc. dated June 23, 2006 (Exhibit 4.3. Form 10-Q for the quarter ended June 30, 2006, File No. 1-8489, incorporated by reference).

4.13 Replacement Capital Covenant entered into by Dominion Resources, Inc. dated September 29, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2006, File No. 1-8489, incorporated by reference).

10.1 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).

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

10.3 Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-8489, incorporated by reference).

10.4 $3.0 billion Five-Year Credit Agreement dated February 28, 2006 among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company, JP Morgan Chase Bank, N.A., as Administrative Agent, Citibank, N.A. as Syndication Agent and Barclay's Bank PLC, The Bank of Nova Scotia and Wachovia Bank, National Association, as Co-Documentation Agents and other lenders named therein. (Exhibit 10.1, Form 8-K filed March 3, 2006, File No. 1-8489, incorporated by reference).

10.5 $1.70 billion Amended and Restated Five-Year Credit Agreement dated February 28, 2006 among Consolidated Natural Gas Company, Barclay's Bank PLC, as Administrative Agent, Barclays Bank PLC and KeyBank National Association, as Syndication Agents, and SunTrust Bank, The Bank of Nova Scotia and ABN AMRO Bank, N.V., as Co-Documentation Agents and other lenders as named therein. (Exhibit 10.2, Form 8-K filed March 3, 2006, File No. 1-8489, incorporated by reference).

10.6 $1.05 billion 364-Day Credit Agreement dated February 28, 2006 among Consolidated Natural Gas Company, Barclays Bank PLC, as Administrative Agent, Barclays Bank PLC and KeyBank National Association, as Syndication Agents, The Bank of Nova Scotia, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents and other lenders as named therein. (Exhibit 10.3, Form 8-K filed March 3, 2006, File No. 1-8489, incorporated by reference).

10.7 $500 million 364-Day Revolving Credit Agreement dated July 30, 2008 among Dominion Resources, Inc., The Royal Bank of Scotland PLC, as Administrative Agent, Barclays Bank PLC and Morgan Stanley Bank, as Co-Syndication Agents, Citibank N.A. and The Bank of Nova Scotia, as Co-Documentation Agents and other lenders named therein (Exhibit 10.1, Form 10-Q for the quarter ended September 30, 2008, 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), as amended June 20, 2007 (Exhibit 10.9, Form 10-K for the fiscal year ended December 31, 2007, 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), as amended April 27, 2007 (Exhibit 10.10, Form 10-K for the fiscal year ended December 31, 2007, File No. 1-8489, incorporated by reference).

10.12* Form of Employment Continuity Agreement for certain officers of Dominion, amended and restated July 15, 2003 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003, File No. 1-8489, incorporated by reference), as amended March 31, 2006 (Form 8-K filed April 4, 2006, File No. 1-8489, incorporated by reference).

10.13* 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).

10.14* 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).

10.15* 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).

10.16* Dominion Resources, Inc. New Executive Supplemental Retirement Plan, effective January 1, 2005 (Exhibit 10.8, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference), amended January 19, 2006 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2005, File No. 1-8489, incorporated by reference), as amended December 1, 2006 and further amended January 1, 2007 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2006, File No. 1-8489, incorporated by reference), as amended and restated effective January 1, 2009 (Exhibit 10.3, Form 10-Q for the quarter ended September 30, 2008, incorporated by reference).

10.17* 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), as amended January 1, 2007 (Exhibit 10.18, Form 10-K for the fiscal year ended December 31, 2006, File No. 1-8489, incorporated by reference), as amended and restated effective January 1, 2009 (Exhibit 10.4, Form 10-Q for the quarter ended September 30, 2008, incorporated by reference), as amended and restated effective January 1, 2009 (filed herewith).

10.18* 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).

10.19*	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).
10.20*	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).
10.21*	Dominion Resources, Inc. Non-Employee Directors' Compensation Plan, effective January 1, 2005, as amended and restated effective January 1, 2008 (Exhibit 10.21, Form 10-K for the fiscal year ended December 31, 2007, File No. 1-8489, incorporated by reference), as amended and restated effective January 1, 2009 (filed herewith).
10.22*	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).
10.23*	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 16, 2005, File No. 1-8489, incorporated by reference).
10.24*	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).
10.25*	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).
10.26*	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).
10.27*	Employment agreement dated February 13, 2007 between Dominion Resources Services, Inc. and Mark F. McGettrick (Exhibit 10.34, Form 10-K for the fiscal year ended December 31, 2006, File No. 1-8489, incorporated by reference).
10.28*	Supplemental retirement agreement dated April 22, 2005 between Dominion and Mark F. McGettrick (Exhibit 10.36, Form 10-K for the fiscal year ended December 31, 2005, File No. 1-8489, incorporated by reference).
10.29*	Supplemental retirement agreement dated October 22, 2003 between Dominion and Paul D. Koonce (Exhibit 10.18, Form 10-K for the fiscal year ended December 31, 2003, File No. 1-2255, incorporated by reference).
10.30*	Supplemental Retirement Agreement dated December 12, 2000, between the Company and David A. Christian (Exhibit 10.25, Form 10-K for the fiscal year ended December 31, 2001, File No. 1-2255, incorporated by reference).
10.31*	Letter Agreement between Consolidated Natural Gas Company and George A. Davidson, Jr. dated December 22, 1998, related letter dated January 8, 1999 and Amendment to Letter Agreement dated February 26, 2008 (Exhibit 10.37, Form 10-K for the fiscal year ended December 31, 2007, File No. 1-8489, incorporated by reference).
10.32*	Form of Restricted Stock Grant under 2006 Long-Term Compensation Program approved March 31, 2006 (Exhibit 10.1, Form 8-K filed April 4, 2006, File No. 1-8489, incorporated by reference).
10.33*	Form of Performance Grant under 2006 Long-Term Compensation Program approved March 31, 2006, as amended and restated January 24, 2008 (Exhibit 10.1, Form 8-K filed January 30, 2008, File No. 1-8489, incorporated by reference).
10.34*	Form of Restricted Stock Grant under 2007 Long-Term Compensation Program approved March 30, 2007 (Exhibit 10.1, Form 8-K filed April 5, 2007, File No. 1-8489, incorporated by reference).
10.35*	Form of Performance Grant under 2007 Long-Term Compensation Program approved March 30, 2007 (Exhibit 10.2, Form 8-K filed April 5, 2007, File No. 1-8489, incorporated by reference).
10.36	Offshore Package Purchase Agreement between Dominion Exploration & Production, Inc. and Eni Petroleum dated April 27, 2007. (Exhibit 10.5 to Form 10-Q for the quarter ending March 31, 2007, filed May 3, 2007, File No. 1-8489, incorporated by reference).
10.37	Alabama/Permian Package Purchase Agreement dated as of June 1, 2007 between Dominion Resources, Inc., through certain of its wholly owned subsidiaries, and L O & G Acquisition Corp. (Exhibit 10.1, Form 8-K filed June 7, 2007, File No. 1-8489, incorporated by reference).
10.38	Gulf Coast/Rockies/San Juan Package Purchase Agreement dated as of June 1, 2007 between Dominion Resources, Inc. through certain of its wholly owned subsidiaries, and XTO Energy, Inc. (Exhibit 10.2, Form 8-K filed June 7, 2007, File No. 1-8489, incorporated by reference).

10.39*	Form of Restricted Stock Award Agreement under 2008 Long-Term Compensation Program approved March 27, 2008 (Exhibit 10.1, Form 8-K filed April 2, 2008, File No. 1-8489, incorporated by reference).
10.40*	2008 Performance Grant Plan under 2008 Long-Term Compensation Program approved March 27, 2008 (Exhibit 10.2, Form 8-K filed April 2, 2008, File No. 1-8489, incorporated by reference).
10.41*	Restricted Stock Award Agreement for Thomas N. Chewning approved March 27, 2008 (Exhibit 10.3, Form 8-K filed April 2, 2008, File No. 1-8489, incorporated by reference).
10.42*	Form of Advancement of Expenses for certain directors and officers of Dominion, approved by the Dominion Board of Directors on October 24, 2008 (Exhibit 10.2, Form 10-Q for the quarter ended September 30, 2008, File No. 1-8489, incorporated by reference).
10.43*	2009 Performance Grant Plan under 2009 Long-Term Compensation Program approved January 26, 2009 (Exhibit 10.1, Form 8-K filed January 29, 2009, File No. 1-8489, incorporated by reference).
10.44*	Form of Restricted Stock Award Agreement under 2009 Long-Term Compensation Program approved January 26, 2009 (Exhibit 10.2, Form 8-K filed January 29, 2009, File No. 1-8489, incorporated by reference).
10.45*	Base salaries for named executive officers (filed herewith).
10.46*	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.*

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, Chairman, President and Chief Executive Officer)

Date: February 26, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 26th day of February, 2009.

Signature	Title
/s/ THOMAS F. FARRELL, II **Thomas F. Farrell, II**	Chairman of the Board of Directors, President and Chief Executive Officer
/s/ PETER W. BROWN **Peter W. Brown**	Director
/s/ GEORGE A. DAVIDSON, JR. **George A. Davidson, Jr.**	Director
/s/ JOHN W. HARRIS **John W. Harris**	Director
/s/ ROBERT S. JEPSON, JR. **Robert S. Jepson, Jr.**	Director
/s/ MARK J. KINGTON **Mark J. Kington**	Director
/s/ BENJAMIN J. LAMBERT, III **Benjamin J. Lambert, III**	Director
/s/ MARGARET A. MCKENNA **Margaret A. McKenna**	Director
/s/ FRANK S. ROYAL **Frank S. Royal**	Director
/s/ DAVID A. WOLLARD **David A. Wollard**	Director
/s/ THOMAS N. CHEWNING **Thomas N. Chewning**	Executive Vice President and Chief Financial Officer
/s/ THOMAS P. WOHLFARTH **Thomas P. Wohlfarth**	Senior Vice President and Chief Accounting Officer