Large Filing Separator Sheet

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Description of Document: Renewal Application tributions 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 20. 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, 2007 or 2006.

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, 2007 and 2006. 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, 2007:

Dividend	Issued and Outstanding Shares	Entitled Per Share Upon Liquidation
	(thousands)	
$5.00	107	$112.50
4.04	13	102.27
4.20	15	102.50
4.12	32	103.73
4.80	73	101.00
7.05	500	102.12[1]
6.98	600	102.10[2]
Flex MMP 12/02, Series A	1,250	100.00[3]
Total	2,590	

(1) Through 7/31/2008; $101.77 commencing 8/1/2008; amounts decline in steps thereafter to $100.00 by 8/1/2013.

(2) Through 8/31/2008; $101.75 commencing 9/1/2008; 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 21. SHAREHOLDERS' EQUITY

Issuance of Common Stock

In 2007, we received cash proceeds of $226 million for 7.6 million shares issued in connection with the exercise of employee stock options. During 2007, we purchased our common stock on the open market with the proceeds received through Dominion Direct® (a dividend reinvestment and open enrollment direct stock purchase plan) and employee savings plans, rather than having additional new common shares issued. In January 2008, we began issuing additional new common shares to be used for these programs.

Repurchases of Common Stock

In 2007, we repurchased 129.0 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.

In December 2006, we entered into a prepaid accelerated share repurchase agreement (ASR) with a financial institution as the counterparty. Under the ASR, we would receive between 11.2 million and 13.0 million shares in exchange for the prepayment. At the time of execution of the ASR, we made a prepayment of $500 million and the counterparty initially delivered approximately 10.1 million shares to us. The final number of shares to be delivered to the Company was determined by the volume weighted average price of our common stock over the period commencing on December 12, 2006 and terminating on May 16, 2007. In May 2007, the counterparty delivered approximately 1.6 million additional shares to us in completion of the ASR.

At December 31, 2007, 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.

Shares Reserved for Issuance

At December 31, 2007, we had a total of 46 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,	2007	2006
(millions)		
Net unrealized losses on derivatives—hedging activities, net of tax of $30 and $266, respectively	$ (42)	$(422)
Net unrealized gains on investment securities, net of tax of $116 and $187, respectively	180	282
Net unrecognized pension and other postretirement benefit costs, net of tax of $149 and $239, respectively	(150)	(335)
Foreign currency translation adjustments	—[1]	50
Total accumulated other comprehensive loss	$ (12)	$(425)

(1) Decrease is due to the sale of our Canadian E&P business in June 2007.

Stock-Based Awards

In April 2005, our shareholders approved the 2005 Incentive Compensation Plan (2005 Incentive Plan) for employees and the Non-Employee Directors Compensation Plan (Non-Employee Directors Plan). The 2005 Incentive Plan permits stock-based awards that include restricted stock, performance grants, goal-based stock and stock options, and the Non-Employee Directors

Plan permits restricted stock and stock options. Under provisions of both plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms are set at the discretion of the Compensation, Governance and Nominating (CGN) Committee of the Board of Directors or the Board of Directors itself, as provided under each individual plan. At December 31, 2007, approximately 29 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, 2007, 2006 and 2005 include $57 million, $31 million and $25 million, respectively, of compensation costs and $21 million, $11 million and $10 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in our *Consolidated Statements of Income.*

Stock Options

The following table provides a summary of changes in amounts of stock options outstanding as of and for the years ended December 31, 2007, 2006 and 2005. No options were granted under any plan in 2007, 2006 or 2005.

	Shares	Weighted-average Exercise Price	Weighted-average Remaining Contractual Life	Aggregated Intrinsic Value [1]
	(thousands)		(years)	(millions)
Outstanding at December 31, 2004	27,616	$30.09		
Exercisable at December 31, 2004	21,536	$30.01		
Exercised	(11,158)	$29.90		$ 77
Forfeited/expired	(30)	$31.27		
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**	**2.8**	**$120**

(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 $226 million, $54 million and $335 million in the years ended December 31, 2007, 2006 and 2005, 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, 2007, 2006 and 2005:

	Shares	Weighted-average Grant Date Fair Value
	(thousands)	
Nonvested at December 31, 2004	1,920	$30.17
Granted	498	37.26
Vested	(60)	31.23
Cancelled and forfeited	(96)	31.64
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**

As of December 31, 2007, unrecognized compensation cost related to nonvested restricted stock awards totaled $25 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 $30 million, $14 million and $2 million in 2007, 2006 and 2005, 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 value of Dominion stock and the applicable federal, state and local tax withholding rates.

Goal-Based Stock

Goal-based stock awards are generally granted to key non-officer employees on an annual basis. Goal-based stock awards were also granted in lieu of cash-based performance grants to certain officers who had not achieved a certain level of share ownership. The issuance of awards is based on the achievement of multiple performance metrics during a two-year period, including return on invested capital and total shareholder return relative to that of a peer group of companies. The actual number of shares issued will vary between zero and 200% of targeted shares depending on the level of performance metrics achieved. The fair value of goal-based stock is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of goal-based stock activity for the years ended December 31, 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**

At December 31, 2007, the targeted number of shares expected to be issued under these awards was approximately 289 thousand. In January 2008, the CGN determined that the total number of shares expected to be issued under the goal-based stock awards is 359 thousand, based on the actual performance against metrics, as amended in January 2008, established for those awards whose performance period ended on December 31, 2007.

As of December 31, 2007, 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

In April 2006, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2008 and is based on the achievement of two performance metrics during 2006 and 2007: return on invested capital and total shareholder return relative to that of a peer group of companies. Actual payout will vary between zero and 200% of the targeted amount, depending on the level of performance metrics achieved. At December 31, 2007, the targeted amount of the grant was $13 million, however the actual payout will be $18 million based on the performance metrics achieved.

In April 2007, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2009 and is based on the achievement of two performance metrics during 2007 and 2008: return on invested capital and total shareholder return relative to that of a peer group of companies. At December 31, 2007, the targeted amount of the grant is $14 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved.

At December 31, 2007, a liability of $25 million has been accrued for these awards.

Note 22. 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, 2007, 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, 2007.

See Note 19 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 23. 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 generally contribute annually an amount that is in accordance with the provisions of the Employment Retirement Income Security Act of 1974. The pension program also provides benefits to certain retired executives under company-sponsored nonqualified employee benefit plans. Certain of these nonqualified plans are funded through contributions to a grantor trust.

We provide retiree health care and life insurance benefits with annual employee premiums based on several factors such as age, retirement date and years of service.

In 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 have determined that the prescription drug benefit offered under our other postretirement benefit plans is at least actuarially equivalent to Medicare Part D and therefore, we expect to receive the federal subsidy offered under the Medicare Act.

We 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 pension plan assets, a component of net periodic pension cost. The market-related value recognizes changes in fair value on a straight-line basis over a four-year period. Changes in fair value are measured as the difference between the expected and actual plan asset returns, including dividends, interest and realized and unrealized investment gains and losses.

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,	**2007**	2006	**2007**	2006
(millions)				
Change in benefit obligation:				
Benefit obligation at beginning of year	**$3,666**	$3,834	**$1,297**	$1,622
Service cost	**112**	124	**55**	72
Interest cost	**222**	210	**77**	81
Benefits paid	**(164)**	(175)	**(69)**	(72)
Actuarial (gain) loss during the year[1]	**(139)**	(329)	**125**	(395)
Plan amendments	**4**	2	**(14)**	(11)
Curtailments	**(8)**	—	**(7)**	—
Benefit obligation at end of year	**$3,693**	$3,666	**$1,464**	$1,297
Change in plan assets:				
Fair value of plan assets at beginning of year	**$4,793**	$4,360	**$ 909**	$ 794
Actual return on plan assets	**461**	589	**59**	85
Contributions	**8**	19	**25**	68
Benefits paid from plan assets	**(164)**	(175)	**(33)**	(38)
Fair value of plan assets at end of year	**$5,098**	$4,793	**$ 960**	$ 909
Funded status at end of year	**$1,405**	$1,127	**$ (504)**	$ (388)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	**$1,544**	$1,240	**$ 21**	$ 6
Other current liabilities	**(29)**	(2)	**(2)**	—
Other deferred credits and other liabilities	**(110)**	(111)	**(523)**	(394)
Net amount recognized	**$1,405**	$1,127	**$ (504)**	$ (388)

(1) The actuarial gains for pension benefits primarily resulted from an increase in the discount rate for 2007 and an increase in the discount rate and the expected retirement age for 2006. The 2006 actuarial gain for other postretirement benefits primarily resulted from an increase in the discount rate and a decrease in expected future benefit claims.

The accumulated benefit obligation (ABO) for all of our defined benefit pension plans was $3.2 billion each at December 31, 2007 and 2006. 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.

We do not expect any pension or postretirement benefit plan assets to be returned to the Company during 2008.

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,	**2007**	2006	**2007**	2006
(millions)				
Benefit obligation	**$139**	$131	**$1,328**	$1,159
Fair value of plan assets	**—**	18	**803**	765

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,	**2007**	2006
(millions)		
Accumulated benefit obligation	**$84**	$65
Fair value of plan assets	**—**	—

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

(millions)	Pension Benefits	Other Postretirement Benefits
2008	$ 194	$ 83
2009	177	90
2010	191	97
2011	196	104
2012	212	110
2013-2017	1,341	637

The above benefit payments for other postretirement benefit plans are expected to be offset by Medicare Part D subsidies of approximately $5 million annually for 2008 and 2009, approximately $6 million annually for the period 2010 through 2012 and approximately $39 million during the period 2013 through 2017.

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. 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,	2007		2006		2007		2006	
	Fair Value	% of Total	Fair Value	% of Total	Fair Value	% of Total	Fair Value	% of Total
(millions, except percentages)								
Equity securities:								
U.S.	$1,767	35%	$1,491	31%	$384	40%	$369	41%
International	757	15	751	16	107	11	106	11
Debt securities	1,228	24	1,356	28	347	36	335	37
Real estate	406	8	376	8	31	3	25	3
Other	940	18	819	17	91	10	74	8
Total	$5,098	100%	$4,793	100%	$960	100%	$909	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,	2007	2006	2005	2007	2006	2005
(millions)						
Service cost	$ 112	$ 124	$ 110	$ 55	$ 72	$ 64
Interest cost	222	210	201	77	81	83
Expected return on plan assets	(391)	(357)	(341)	(71)	(62)	(51)
Amortization of prior service (credit) cost	4	4	3	(6)	(4)	(1)
Amortization of transition obligation	—	—	—	3	3	3
Amortization of net loss	37	89	77	6	24	19
Settlements and curtailments(1)	11	12	—	(3)	—	—
Plan amendments(2)	4	—	—	8	—	—
Net periodic benefit (credit) cost	$ (1)	$ 82	$ 50	$ 70	$114	$117
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and regulatory liabilities:						
Current year net actuarial (gain) loss	$(209)	$ —	$ —	$137	$ —	$ —
Prior service (credit) cost	3	—	—	(8)	—	—
Transition asset	—	—	—	(17)	—	—
Settlements and curtailments	(21)	—	—	—	—	—
Less amounts included in net periodic benefit (credit) cost:						
Amortization of net loss	(37)	—	—	(6)	—	—
Amortization of prior service credit (cost)	(4)	—	—	6	—	—
Amortization of transition obligation	—	—	—	(3)	—	—
Plan amendments	—	—	—	(2)	—	—
Change in additional minimum liability	—	(17)	(7)	—	—	—
Total recognized in other comprehensive income and regulatory assets and regulatory liabilities	$(268)	$ (17)	$ (7)	$107	$ —	$ —

(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.

The components of AOCI and regulatory assets and regulatory liabilities that have not been recognized as components of periodic benefit (credit) cost:

	Pension Benefits		Other Postretirement Benefits	
As of December 31,	2007	2006	2007	2006
(millions)				
Transition obligation	$ —	$ —	$ —	$ 20
Net actuarial loss	365	631	185	57
Prior service (credit) cost	23	25	(40)	(39)
Total(1)	$388	$656	$145	$ 38

(1) Of the $388 million and $145 million related to pension benefits and other postretirement benefits, respectively, as of December 31, 2007, $183 million and $116 million, respectively, are included in AOCI. Of the $656 million and $38 million related to pension benefits and other postretirement benefits, respectively, as of December 31, 2006, $561 million and $13 million, respectively, are included in AOCI.

The following table provides the components of AOCI, regulatory assets and regulatory liabilities as of December 31, 2007 that are expected to be amortized as components of periodic benefit cost in 2008:

	Pension Benefits	Other Postretirement Benefits
(millions)		
Net actuarial loss	$7	$ 8
Prior service (credit) cost	4	(6)

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

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	2007	2006	2005	2007	2006	2005
Discount rate	6.20%	5.60%	6.00%	6.10%	5.50%	6.00%
Expected return on plan assets	8.75%	8.75%	8.75%	8.00%	8.00%	8.00%
Rate of increase for compensation	4.79%	4.70%	4.70%	4.70%	4.70%	4.70%
Medical cost trend rate(1)				9.00%	9.00%	9.00%

(1) The medical cost trend rate for 2007 is assumed to gradually decrease to 5.00% by 2011 and continues at that rate for years thereafter.

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

	Pension Benefits		Other Postretirement Benefits	
At December 31,	2007	2006	2007	2006
Discount rate	6.60%	6.20%	6.50%	6.10%
Rate of increase for compensation	4.79%	4.79%	4.70%	4.70%

We determine the expected long-term rates of return on plan assets for pension plans and other postretirement benefit plans by using a combination of:

- Historical return analysis to determine expected future risk premiums;
- Forward-looking return expectations derived from the yield on long-term bonds and the price earnings ratios of major stock market indices;
- Expected inflation and risk-free interest rate assumptions; and
- The types of investments expected to be held by the plans.

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 2007	**$ 20**	**$ (17)**
Effect on postretirement benefit obligation at December 31, 2007	**184**	**(140)**

In addition, we sponsor defined contribution thrift-type savings plans. During 2007, 2006 and 2005, we recognized $37 million, $36 million and $33 million, respectively, as contributions to these plans.

Certain regulatory authorities have held that amounts recovered in utility customers' rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, certain of our subsidiaries fund postretirement benefit costs through Voluntary Employees' Beneficiary Associations (VEBAs). Our remaining subsidiaries do not prefund postretirement benefit costs but instead pay claims as presented. We expect to contribute $32 million to the Dominion VEBAs in 2008.

NOTE 24. 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, 2007, 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:

	2008	2009	2010	2011	2012	Thereafter	Total
(millions)							
Purchased electric capacity[1]	**$383**	**$364**	**$349**	**$348**	**$352**	**$1,857**	**$3,653**

(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, 2007, the present value of our total commitment for capacity payments is $2.4 billion. Capacity payments totaled $410 million, $437 million and $472 million, and energy payments totaled $360 million, $291 million and $378 million for 2007, 2006 and 2005, 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, 2007 are as follows:

	2008	2009	2010	2011	2012	Thereafter	Total
(millions)							
	$81	**$72**	**$58**	**$50**	**$41**	**$151**	**$453**

Rental expense totaled $185 million, $178 million and $160 million for 2007, 2006 and 2005, respectively, the majority of which is reflected in other operations and maintenance expense.

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 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

Mt. Storm Wind Farm

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 construction phases totaling 264 Mw. The first phase (164 Mw) is expected to become fully operational by June 2008 and the second phase is expected to be fully operational by December 2008. During 2007, we made cash contributions of $67 million to NedPower and expect to contribute an additional $57 million in 2008. The remaining cost of both phases is expected to be funded by NedPower through non-recourse construction financing with third-party banks.

Fowler Ridge Wind Farm

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. The facility is expected to be built in two phases and generate a total of 750 Mw. We will jointly own 650 Mw with BP and BP will retain sole ownership of 100 Mw. We have committed to contribute approximately $340 million of cash at various dates through January 2009, which includes our initial investment and funding for the development of the first 300 Mw phase. Construction of the second 350 Mw phase could begin as early as 2009, with funding to be contributed to the joint venture to maintain 50/50 ownership between the partners. Our ultimate funding requirements may decrease to the extent that the joint venture obtains non-recourse construction and term financing.

Environmental Matters

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

To the extent environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 2008, in excess of the level currently included in Virginia jurisdictional rates, our results of operations could decrease. After that date, we may seek recovery through rates.

Superfund Sites

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

Other

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 Nuclear Regulatory Commission (NRC) requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Our 2007 calculation for the NRC minimum financial assurance amount, aggregated for our nuclear units, was $2.4 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.

Nuclear Insurance

The Price-Anderson Act provides the public up to $10.8 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 with the remainder provided through a mandatory industry risk-sharing program. In the event of a nuclear incident at any licensed nuclear reactor in the U.S., we could be assessed up to $100.6 million for each of our seven licensed reactors not to exceed $15 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. The Price-Anderson Act was first enacted in 1957 and was renewed again in 2005.

Our current level of property insurance coverage ($2.55 billion for North Anna power station (North Anna), $2.55 billion for Surry power station, $2.75 billion for Millstone power station (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 $99 million. Based on the severity of the incident, the board of directors of our nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. We have the financial responsibility for any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination.

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

Old Dominion Electric Cooperative, a part owner of North Anna, 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 Department of Energy (DOE) for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by our contracts with the DOE. In January 2004, we and certain of our direct and indirect subsidiaries filed 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. Trial is scheduled for May 2008. 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, 2007, we had issued $41 million of guarantees to support third parties and equity method investees. Additionally, we have issued a limited-scope guarantee and indemnification for one-half of the project-level financing for phase one of the NedPower wind farm project. Under this guarantee, we would be required to repay 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. The 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 the guarantee totaled $56 million as of December 31, 2007 and will increase to $103 million in 2008 based upon NedPower's future expected borrowings to complete phase one. Shell has provided an identical guarantee for the other one-half of NedPower's borrowings.

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, 2007, we had issued the following subsidiary guarantees:

	Stated Limit	Value(1)
(millions)		
Subsidiary debt(2)	$ 48	$ 48
Commodity transactions(3)	2,985	326
Lease obligation for power generation facility(4)	917	917
Nuclear obligations(5)	383	302
Other	341	192
Total	$4,674	$1,785

(1) Represents the estimated portion of the guarantee's stated limit that is utilized as of December 31, 2007 based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by our subsidiaries, the value includes the recorded amount.

(2) Guarantees of debt of a DEI subsidiary. In the event of default by the subsidiary, we would be obligated to repay such 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. In addition to the guarantees listed above, we have also agreed to provide up to $150 million and $60 million to two DEI subsidiaries, to pay 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.

Additionally, as of December 31, 2007, we had purchased $56 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $230 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, 2007, we believe future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

We have entered into other types of contracts that require indemnifications, such as purchase and sale agreements and financing agreements. These agreements may include, but are not limited to, indemnifications around certain title, tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price and is typically limited in duration depending on the nature of the indemnified matter. Since January 1, 2005, we have entered into sale agreements with maximum exposure related to the collective purchase prices of approximately $15 billion. We believe that it is improbable 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 Restructuring Act and Fuel Factor Amendments

On July 1, 2007, legislation amending the Virginia Electric Utility Restructuring Act (the Restructuring Act) and the fuel factor became effective, which significantly changes electricity regulation in Virginia. Prior to the Restructuring Act, our base rates in Virginia were capped at 1999 levels until December 31, 2010. The Restructuring Act ends capped rates two years early, on December 31, 2008. After capped rates end, retail choice will be eliminated for all but 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 be permitted to purchase renewable energy from competitive suppliers if the incumbent electric utility does not offer a renewable energy tariff. Also after the end of capped rates, the Virginia Commission will set our base rates under a modified cost-of-service model. Among other features, the new model provides for the Virginia Commission to:

- Initiate a base rate case during the first six months of 2009, reviewing the 2008 test year, as a result of which the Virginia Commission:
  - shall establish a return on equity (ROE) no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earnings more than 50 basis points below the established ROE; or
  - may reduce rates prospectively upon completion of the 2009 review or, alternatively, order a credit to customers if we are found to have test year earnings of more than 50 basis points above the established ROE.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - shall establish an ROE no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - after 2010, authorize an increased ROE on overall rate base upon achieving the goals established for the renewable energy portfolio standard programs. Such increased ROE would be in lieu of any increased or decreased ROE from the preceding paragraph, unless there has been an increase to the ROE awarded under the preceding paragraph that is higher than the renewable energy portfolio standard increase; and
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earned, during the test period, more than 50 basis points below the then currently established ROE; or
  - may order a credit to customers if we are found to have earned, during the test period, more than 50 basis points above the then currently established ROE, and reduce rates if we are found to have such excess earnings during two consecutive biennial review periods.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service and energy efficiency, conservation, and renewable energy programs; and
- Authorize an enhanced ROE on new capital expenditures as a financial incentive for construction of certain major generation projects.

The legislation 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*.

As discussed previously, the legislation provides for the Virginia Commission to initiate a base rate case during the first six months of 2009, as a result of which the Virginia Commission may reduce rates or alternatively, order a credit to customers if we are found to have earnings more than 50 basis points above the established 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.

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 have increased considerably since 2004, 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 on 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. Under these amendments, our fuel factor increase as of July 1, 2007 was limited to an amount that results 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 to be deferred and subsequently recovered subject to Virginia Commission approval, without interest, during the period commencing July 1, 2008 and ending June 30, 2011.

Stranded Costs

Stranded costs are generation-related costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market. In the past, our exposure to potential stranded costs included long-term power purchase contracts that could ultimately be determined to be above market prices; generating plants that could possibly become uneconomical in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits. Capped electric retail rates provided an opportunity to recover our potential stranded costs, depending on market prices of electricity and other factors. Recovery of our potential stranded costs was subject to numerous risks even in the capped-rate environment. Those risks included, among others, exposure to long-term power purchase commitment losses, future environmental compliance requirements, changes in certain tax laws, nuclear decommissioning costs, increased fuel costs, inflation, increased capital costs and recovery of certain other items. However, with the return to a modified cost-of-service rate model under the 2007 Virginia Restructuring Act Amendments, our exposure to potential stranded costs and the risk of non-recovery will be eliminated.

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 change under annual fuel cost adjustment proceedings.

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 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 are subject to FERC approval.

Dominion Cove Point Rates

In June 2006, we filed a general rate proceeding for Dominion Cove Point LNG, LP (DCP). The rates established in this case took effect on January 1, 2007. This rate proceeding enabled DCP to update the cost of service underlying its rates, including recovery of costs associated with the 2002 to 2003 reactivation of the LNG import terminal. The FERC-approved settlement established a rate moratorium that ends in mid-2011.

Litigation

In 2006, Gary P. Jones and others filed suit against DTI, DEPI and Dominion Resources Services, Inc. (DRS). The plaintiffs are royalty owners, seeking to recover damages as a result of the Dominion defendants allegedly underpaying royalties by improperly deducting post-production costs and not paying fair market value for the gas produced from their leases. The plaintiffs seek class action status on behalf of all West Virginia residents and others who are parties to or beneficiaries of oil and gas leases with the Dominion defendants. DRS is erroneously named as a defendant as the parent company of DTI and DEPI. 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.

NOTE 25. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

At December 31,	2007		2006	
	Carrying Amount	Estimated Fair Value[1]	Carrying Amount	Estimated Fair Value[1]
(millions)				
Long-term debt[2]	**$13,236**	**$13,377**	$15,320	$15,576
Junior subordinated notes payable to:				
Affiliates	**678**	**681**	1,151	1,209
Other	**798**	**804**	798	828

(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 valuation of certain fair value hedges associated with our fixed-rate debt.

NOTE 26. 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, 2007 provision for credit losses, that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

As a diversified energy company, we transact with major companies in the energy industry and with commercial and residential energy consumers. These transactions principally occur in the Northeast, mid-Atlantic and Midwest regions of the U.S. We do not believe that this geographic concentration contributes significantly to our overall exposure to credit risk. In addition, as a result of our large and diverse customer base, we are not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations, including transmission services and retail energy sales.

Our exposure to credit risk is concentrated primarily within our energy marketing and price risk management activities, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include trading of energy-related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. 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, 2007, our gross credit exposure totaled $808 million. After the application of collateral, our credit exposure is reduced to $705 million. Of this amount, investment grade counterparties, including those internally rated, represented 94% and no single counterparty exceeded 12%.

NOTE 27. EQUITY AND COST-METHOD INVESTMENTS

Equity-Method Investments

At December 31, 2007 and 2006, our equity method investments totaled $331 million and $289 million, respectively, and equity earnings on these investments totaled $35 million in 2007, $37 million in 2006 and $43 million in 2005. We received dividend income from these investments of $16 million, $21 million and $28 million in 2007, 2006 and 2005, respectively. 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. Our equity method investments are reported in our Consolidated Balance Sheets in other investments. Equity earnings on these investments are reported in other income in our Consolidated Statements of Income.

Cost-Method Investments

At December 31, 2007 and 2006, the carrying value of our cost-method investments totaled $34 million and $37 million, respectively. Our cost method investments are reported in our Consolidated Balance Sheets in other investments. In 2007 and 2006, we reviewed all of our cost method investments for evidence of adverse changes in fair value; however, we did not estimate the fair value of our cost-method investments unless we identified events or changes in circumstances that had a significant adverse effect on the fair value of the investments.

Note 28. Dominion Capital, Inc.

Our Consolidated Balance Sheets reflect the following DCI assets:

At December 31,	2007	2006
(millions)		
Current assets[1]	**$266**	$229
Loans held for resale	**323**	—
Loans receivable, net	**34**	399
Available-for-sale securities	**—**	39
Other investments	**72**	81
Property, plant and equipment, net	**—**	10
Deferred charges and other assets	**127**	83
Total	**$822**	$841

(1) Includes $30 million of loans held for resale in 2007. Includes $36 million of loans receivable, net in 2006.

Securitizations of Financial Assets

At December 31, 2006, DCI held $39 million of retained interests from the securitization of financial assets, which were classified as available-for-sale securities. The retained interests resulted from prior year securitizations of CDO and collateralized mortgage obligation (CMO) transactions. 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 the fourth quarter of 2007. DCI still owns six residual trusts with no book basis.

We executed certain agreements in 2003 that resulted in the sale of certain financial assets in exchange for an investment in the subordinated notes of a third-party CDO entity. This investment consisted of $100 million of Class B-1 Notes, 7.5% current pay interest and $148 million of Class B-2 Notes, 3% paid-in-kind (PIK) interest. The equity interest in the new CDO entity, a voting interest entity, were held by an entity that is not affiliated with us. 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.

Prior to June 2006, our intent was to rate and market the B-1 Notes and hold the B-2 Notes to maturity. DCI also had a commitment to fund up to $15 million of liquidity to the CDO entity, but this commitment has expired.

In 2006, we decided to pursue the sale of the B-2 Notes and recorded an $85 million charge in other operations and maintenance expense reflecting an other-than-temporary decline in the fair value of the B-2 Notes. An impairment was required because of a further increase in interest rates, an increase in our credit risk associated with the equity reduction discussed below and because we no longer expected the fair value of the B-2 Notes to recover prior to a sale. During 2007, we recorded a LOCOM adjustment on the B-1 and B-2 notes of $54 million ($35 million after-tax) due to a deterioration in value of the underlying collateral. DCI will continue its efforts to sell the B-1 and B-2 notes in 2008.

DCI's investments in the CDO entity were previously included in available-for-sale securities in our Consolidated Balance Sheet. In 2006, the equity investor reduced its equity at risk in the CDO entity, which required a redetermination of whether the CDO entity is a VIE under FIN 46R. We concluded that the CDO entity is a VIE and that DCI is the primary beneficiary of the CDO entity, which we consolidate in accordance with FIN 46R. Due to its consolidation, we reflect the assets and liabilities of the CDO entity in our Consolidated Balance Sheet. At December 31, 2007 and 2006, the CDO entity had $460 million and $385 million, respectively, of notes payable that mature in January 2017 and are nonrecourse to us. The CDO entity held the following assets that served as collateral for its obligations:

As of December 31,	2007	2006
(millions)		
Other current assets[1]	**$257**	$183
Loans held for resale	**323**	—
Loans receivable, net	**—**	367
Other investments	**32**	36
Total assets	**$612**	$586

(1) Includes $30 million of loans held for resale in 2007. Includes $36 million of loans receivable, net in 2006.

There were no mortgage securitizations in 2006 or 2007. Activity for the subordinated notes related to the CDO entity, retained interests from securitizations of CMOs and CDO retained interests is summarized as follows:

		Retained Interests
	CMO	—CDO[1]
(millions)		
Balance at January 1, 2006	$ 38	$ 255
Interest income	—	12
Consolidation of CDO	—	(171)
Cash received	(1)	(11)
Fair value adjustment	2	(85)
Balance at December 31, 2006	$ 39	$ —
Cash received	**(10)**	—
Fair value adjustment	**(29)**[2]	—
Balance at December 31, 2007	**$ —**	**$ —**

(1) Includes interest receivable.
(2) Includes the reversal of an unrealized gain of $2 million recorded in 2006, plus a $27 million impairment loss due to the write-down of the CMOs.

Loans Related to the CDO Entity

Presented below are the significant accounting policies associated with loans held for resale reflected on our Consolidated Balance Sheet due to consolidation of the CDO entity.

Loans Held for Resale

We report loans held for resale at LOCOM. We determine any LOCOM adjustment to the loans held for sale on a pool basis by aggregating those loans based on similar risks and characteristics. The fair value of the loans are calculated by discounting scheduled cash flows through the estimated maturity using estimated market discount rates that reflect the credit and interest rate risk inherent in the loan, current economic conditions, and lending conditions. The estimates of maturity are based on historical experience with repayments for each loan classification.

A loan is considered non-performing if it meets the definition of either a (i) Defaulted Security, or (ii) PIK Security, where interest has been deferred or paid-in-kind for three months (or 6 months in the case of a security that is only required to pay interest on a quarterly basis).

- In general, a Defaulted Security is: 1) a loan where a default as to the payment of principal and/or interest has occurred and is continuing, 2) a loan that has a Standard & Poor's rating of "D" or "SD" or has a Moody's rating of "Ca" or lower; or,

3) a loan that in the reasonable business judgment of the CDO entity's collateral manager, is a Defaulted Security.

- In general, a PIK Security is a loan with respect to which the obligor has the right to defer or capitalize all or a portion of the interest due on such loan as principal, unless such asset is required on each payment date to pay in cash a spread of at least the LIBOR plus 2.50%.

The CDO entity's loan balances are summarized as follows:

As of December 31,	2007			2006		
	Performing	Non-performing	Total	Performing	Non-performing	Total
(millions)						
Loans[1]	**$538**	**$11**	**$549**	$521	$21	$542
Unamortized premiums, discounts and other cost basis adjustments, net	**(131)**	**(3)**	**(134)**	(127)	(5)	(132)
LOCOM adjustments[2]	**(54)**	**(8)**	**(62)**	—	—	—
Allowance for loan losses	—	—	—	(2)	(5)	(7)
Loans, net	**$353**	**$—**	**$353**	$392	$11	$403

(1) Current portion: Performing—$30 million and $28 million in 2007 and 2006, respectively; Non-performing—$8 million in 2006.

(2) Includes $1 million and $7 million of allowances for loan losses recorded during 2007 prior to the reclassification of loans receivable to loans held for resale for performing and non-performing, respectively.

The notional value of the non-performing portfolio at December 31, 2007 and 2006, was $149 million and $148 million, respectively. During 2006, the CDO entity recorded provisions for loan losses of $7 million and recorded direct write-offs, net of recoveries amounting to $20 million. The interest income earned from cash collections on non-performing loans in 2007 and 2006, was $5 million and $1 million, respectively.

Allowance for Loan Losses

The allowance for loan losses is a significant estimate that represents the CDO entity's estimate of probable losses inherent in the loan portfolio and equity investments as determined by the CDO entity's collateral manager.

In calculating the allowance for loan losses, the CDO entity's collateral manager applies a systematic and consistent approach that considers among other factors: historical payment experience, past-due status, current financial information, ability of the debtors to generate cash flows and realizable value of collateral on a loan by loan basis. Each material non-performing loan and material equity investment is reviewed on a quarterly basis. A range of probable losses is estimated for each loan after which a probable loss is determined.

A loan is written off when it is considered fully uncollectible and of such little value that its continuance as an asset is not warranted. A loan or equity investment is also written off if the borrower has ceased operations, the majority of the borrower's assets have been liquidated or sold, or the remaining collections of the loans are speculative and expected to be minimal or highly contingent.

Loan Origination Fees and Costs

Loan origination fees and costs are deferred and recorded as part of loans held for resale and then amortized over the life of the loan as an adjustment to the yield in interest income.

Deferred Financing Closing

Costs incurred to refinance debt are deferred and amortized over the life of the notes. All costs associated with any notes that are paid in full are expensed at the date of the payoff.

Key Economic Assumptions and Sensitivity Analyses

The loans held for resale held by the CDO entity are subject to credit loss and interest rate risk. Adverse changes of up to 10% in credit losses and interest rates are estimated in each case to have less than a $40 million pre-tax impact on future results of operations.

Impairment Losses

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

Year Ended December 31,	2007	2006	2005
(millions)			
Retained interests from CMO securitizations[1]	**$27**	$—	$25
Loans held for resale[2]	**54**	—	—
Retained interests from CDO securitizations[1]	**—**	85	—
Venture capital and other equity investments[3]	**17**	6	10
Total	**$98**	$91	$35

(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 CMO securitizations in 2007 and 2005 and retained interests from CDO securitizations in 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 29. Operating Segments

We are organized primarily on the basis of products and services sold in the U.S. During the fourth quarter of 2007, we realigned our business units to reflect our strategic refocusing and began managing our daily operations through four operating segments. All segment information for prior years has been recast to conform to the new segment structure. A description of our segments follows:

DVP includes our regulated electric distribution and electric transmission operations in Virginia and North Carolina, as well as nonregulated retail energy marketing and all customer service 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 Appalachian natural gas E&P business. Dominion Energy also includes producer services, which aggregates gas supply, provides market-based services related to gas transportation and storage and engages in associated gas trading and marketing.

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, which are in the process of being divested, 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 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.

In 2005, we reported net expenses of $133 million in the Corporate and Other segment attributable to our operating segments. The net expenses in 2005 primarily related to the impact of the following items attributable to Dominion Generation:

- A $77 million charge ($47 million after-tax) resulting from the termination of a long-term power purchase agreement; and
- A $51 million charge related to credit exposure associated with the bankruptcy of Calpine Corporation. At December 31, 2005, we had not recognized any deferred tax benefits related to the charge, since realization of tax benefits was not anticipated based on our expected future tax profile at that time.

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)						
2007						
Total revenue from external customers	$2,757	$1,970	$7,606	$2,089	$ 1,252	$15,674
Intersegment revenue	140	1,525	135	596	(2,396)	—
Total operating revenue	2,897	3,495	7,741	2,685	(1,144)	15,674
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	795	(140)	1,175
Income tax expense	263	241	494	785	—	1,783
Extraordinary item, net of tax	—	—	—	(158)	—	(158)
Loss from discontinued operations, net of tax	—	—	—	(8)	—	(8)
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						
Total revenue from external customers	$2,514	$2,313	$6,971	$3,564	$ 935	$16,297
Intersegment revenue	76	1,218	137	621	(2,052)	—
Total operating revenue	2,590	3,531	7,108	4,185	(1,117)	16,297
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	595	(87)	1,028
Income tax expense	263	232	351	81	—	927
Loss from discontinued operations, net of tax	—	—	—	(150)	—	(150)
Net income	411	347	537	85	—	1,380
Investment in equity method investees	6	98	119	66	—	289
Capital expenditures	523	493	1,018	2,018	—	4,052
Total assets (billions)	7.8	8.4	16.1	25.2	(8.2)	49.3
2005						
Total revenue from external customers	$2,357	$2,783	$8,035	$3,320	$ 1,314	$17,809
Intersegment revenue	56	1,365	203	502	(2,126)	—
Total operating revenue	2,413	4,148	8,238	3,822	(812)	17,809
Depreciation, depletion and amortization	282	180	351	548	(2)	1,359
Equity in earnings of equity method investees	1	13	21	8	—	43
Interest income	6	17	61	146	(138)	92
Interest and related charges	156	104	264	558	(138)	944
Income tax expense (benefit)	233	230	224	(114)	—	573
Income from discontinued operations, net of tax	—	—	—	6	—	6
Cumulative effect of change in accounting principle, net of tax	—	—	—	(6)	—	(6)
Net income (loss)	378	362	416	(123)	—	1,033

At December 31, 2007, none of our long-lived assets and no significant percentage of our operating revenues were associated with international operations. As of December 31, 2006, approximately 2% of our total long-lived assets were associated with international operations. For the years ended December 31, 2006 and 2005, approximately 1% of our operating revenues were associated with international operations.

Note 30. 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,	2007	2006
(millions)		
Capitalized costs:		
Proved properties	$1,789	$11,747
Unproved properties	10	1,980
Total capitalized costs	1,799	13,727
Accumulated depletion:		
Proved properties	104	3,506
Unproved properties	—	144
Total accumulated depletion	104	3,650
Net capitalized costs	$1,695	$10,077

Total Costs Incurred

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

Year Ended December 31,			2007			2006			2005
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
(millions)									
Property acquisition costs:									
Proved properties	$ 19	$ 19	$—	$ 87	$ 87	$ —	$ 118	$ 118	$—
Unproved properties	77	75	2	171	165	6	151	137	14
Total property acquisition costs	96	94	2	258	252	6	269	255	14
Exploration costs	132	126	6	399	383	16	235	230	5
Development costs(1)	1,114	1,086	28	1,451	1,365	86	1,207	1,128	79
Total	$1,342	$1,306	$36	$2,108	$2,000	$108	$1,711	$1,613	$98

(1) Development costs incurred for proved undeveloped reserves were $445 million, $302 million and $284 million for 2007, 2006 and 2005, respectively.

Results of Operations

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

Year Ended December 31,			2007			2006			2005
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
(millions)									
Revenue (net of royalties) from:									
Sales to nonaffiliated companies	$1,367	$1,291	$76	$1,883	$1,749	$134	$1,499	$1,369	$130
Transfers to other operations	298	298	—	253	253	—	268	268	—
Total	1,665	1,589	76	2,136	2,002	134	1,767	1,637	130
Less:									
Production (lifting) costs	396	369	27	552	510	42	443	406	37
Depreciation, depletion and amortization	536	514	22	801	750	51	564	525	39
Income tax expense	271	262	9	285	271	14	283	264	19
Results of operations	$ 462	$ 444	$18	$ 498	$ 471	$ 27	$ 477	$ 442	$ 35

Company-Owned Reserves

Estimated net quantities of proved gas and oil (including condensate) reserves in the U.S. and Canada at December 31, 2007, 2006 and 2005, and changes in the reserves during those years, are shown in the two schedules that follow:

	2007			2006			2005		
	Total	**U.S.**	**Canada**	Total	U.S.	Canada	Total	U.S.	Canada
(billion cubic feet)									
Proved developed and undeveloped reserves—Gas									
At January 1	**5,136**	**4,961**	**175**	4,962	4,856	106	4,910	4,814	96
Changes in reserves:									
Extensions, discoveries and other additions	**139**	**130**	**9**	431	393	38	299	276	23
Revisions of previous estimates	**88**	**88**	**—**	109	58	51	73	71	2
Production	**(214)**	**(206)**	**(8)**	(318)	(302)	(16)	(290)	(275)	(15)
Purchases of gas in place	**44**	**44**	**—**	48	48	—	55	55	—
Sales of gas in place	**(4,174)**	**(3,998)**	**(176)**	(96)	(92)	(4)	(85)	(85)	—
At December 31	**1,019**	**1,019**	**—**	5,136	4,961	175	4,962	4,856	106
Proved developed reserves—Gas									
At January 1	**3,556**	**3,424**	**132**	3,706	3,605	101	3,685	3,591	94
At December 31	**636**	**636**	**—**	3,556	3,424	132	3,706	3,605	101
Proved developed and undeveloped reserves—Oil									
(thousands of barrels)									
At January 1	**232,259**	**216,849**	**15,410**	217,698	198,602	19,096	164,062	144,007	20,055
Changes in reserves:									
Extensions, discoveries and other additions	**3,094**	**2,853**	**241**	11,373	10,678	695	6,681	5,399	1,282
Revisions of previous estimates(1)	**932**	**932**	**—**	38,010	40,629	(2,619)	63,884	65,264	(1,380)
Production	**(12,185)**	**(11,626)**	**(559)**	(24,947)	(23,923)	(1,024)	(15,575)	(14,714)	(861)
Purchases of oil in place	**3**	**3**	**—**	615	615	—	69	69	—
Sales of oil in place	**(211,490)**	**(196,398)**	**(15,092)**	(10,490)	(9,752)	(738)	(1,423)	(1,423)	—
At December 31(2)	**12,613**	**12,613**	**—**	232,259	216,849	15,410	217,698	198,602	19,096
Proved developed reserves—Oil									
At January 1	**180,779**	**173,718**	**7,061**	152,889	145,735	7,154	113,992	102,152	11,840
At December 31	**12,613**	**12,613**	**—**	180,779	173,718	7,061	152,889	145,735	7,154

(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. The 2005 U.S. revision is primarily due to an increase in plant liquids that resulted from a contractual change for a portion of our gas processed by third parties. We now take title to and market the natural gas liquids extracted from this gas.

(2) Ending reserves for 2007, 2006 and 2005 included 0.3 million, 114.6 million and 127.6 million barrels of oil/condensate, respectively, and 12.3, 117.7 and 90.1 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:

			2007			2006			2005
	Total	**U.S.**	**Canada**	Total	U.S.	Canada	Total	U.S.	Canada
(millions)									
Future cash inflows(1)	**$8,128**	**$8,128**	**$—**	$38,326	$36,604	$1,722	$63,004	$61,112	$1,892
Less:									
Future development costs(2)	**671**	**671**	**—**	3,226	3,052	174	1,979	1,877	102
Future production costs	**1,235**	**1,235**	**—**	7,421	6,936	485	8,127	7,718	409
Future income tax expense	**2,432**	**2,432**	**—**	9,112	8,782	330	19,019	18,527	492
Future cash flows	**3,790**	**3,790**	**—**	18,567	17,834	733	33,879	32,990	889
Less annual discount (10% a year)	**2,346**	**2,346**	**—**	10,458	10,143	315	18,916	18,560	356
Standardized measure of discounted future net cash flows	**$1,444**	**$1,444**	**$—**	$ 8,109	$ 7,691	$ 418	$14,963	$14,430	$ 533

(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 $80 million, $79 million and $87 million for 2008, 2009 and 2010, 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:

	2007	2006	2005
(millions)			
Standardized measure of discounted future net cash flows at January 1	**$ 8,109**	$ 14,963	$ 9,026
Changes in the year resulting from:			
Sales and transfers of gas and oil produced during the year, less production costs	**(1,270)**	(2,791)	(2,502)
Prices and production and development costs related to future production	**289**	(11,788)	8,929
Extensions, discoveries and other additions, less production and development costs	**419**	758	1,396
Previously estimated development costs incurred during the year	**467**	302	284
Revisions of previous quantity estimates	**286**	409	27
Accretion of discount	**181**	2,327	1,367
Income taxes	**3,173**	4,352	(3,659)
Other purchases and sales of proved reserves in place	**(10,197)**	(346)	140
Other (principally timing of production)	**(13)**	(77)	(45)
Standardized measure of discounted future net cash flows at December 31	**$ 1,444**	$ 8,109	$14,963

Note 31. Quarterly Financial and Common Stock Data (Unaudited)

A summary of our quarterly results of operations for the years ended December 31, 2007 and 2006 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 described in Note 6, we reported the operations of our Canadian E&P business and certain DCI businesses as discontinued operations beginning in the second quarter of 2007. Prior quarters for 2007 and 2006 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 2007 and 2006 are a result of reporting the results of these businesses as discontinued operations and the November 2007 stock split.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
(millions, except per share amounts)					
2007					
Operating revenue	**$ 4,661**	**$ 3,730**	**$ 3,589**	**$ 3,694**	**$15,674**
Income (loss) from operations	**1,000**	**(380)**	**4,215**	**732**	**5,567**
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	**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	**0.35**	**0.36**	**0.36**	**0.39**	**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**
2006					
Operating revenue	$ 4,906	$ 3,496	$ 3,973	$ 3,922	$16,297
Income from operations	952	474	1,294	598	3,318
Income from continuing operations	534	146	655	195	1,530
Income (loss) from discontinued operations	—	15	(1)	(164)	(150)
Net income	534	161	654	31	1,380
Basic EPS:					
Income from continuing operations	0.77	0.21	0.93	0.28	2.19
Income (loss) from discontinued operations	—	0.02	—	(0.24)	(0.22)
Net income	0.77	0.23	0.93	0.04	1.97
Diluted EPS:					
Income from continuing operations	0.77	0.21	0.92	0.28	2.17
Income (loss) from discontinued operations	—	0.02	—	(0.24)	(0.21)
Net income	0.77	0.23	0.92	0.04	1.96
Dividends paid per share	0.34	0.35	0.34	0.35	1.38
Common stock prices (high-low)	$40.21-34.44	$38.01-34.36	$40.71-37.22	$42.22-38.02	$42.22-34.36

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 for the recognition of 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.

Our 2006 results include the impact of the following significant items:

- First quarter results include a $94 million after-tax charge resulting from the write-off of certain regulatory assets related to the planned sale of Peoples and Hope, a $222 million tax benefit from the partial reversal of previously recorded valuation allowances on certain federal and state tax loss carryforwards expected to be utilized to offset capital gain income that would have been generated from the planned sale and the establishment of $141 million of deferred tax liabilities associated with the excess of our financial reporting basis over the tax basis in the stock of Peoples and Hope. Results also include a $76 million after-tax benefit resulting from favorable changes in the fair value of certain gas and oil derivatives that were de-designated as hedges following the 2005 hurricanes.
- Second quarter results include an $85 million charge resulting from the impairment of a DCI investment for which no tax benefit had been recognized at that time.
- Third quarter results include a $171 million after-tax benefit from business interruption insurance revenue related to the 2005 hurricanes.
- Fourth quarter results include a $164 million after-tax charge associated with the impairment of the Peaker facilities that were sold in March 2007.

Directors

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Physician,
Virginia Surgical Associates

George A. Davidson, Jr., 69
Retired Chairman,
Dominion Resources, Inc.

Thomas F. Farrell II, 53
Chairman, President and Chief Executive Officer,
Dominion Resources, Inc.

John W. Harris, 60
President,
Lincoln Harris, LLC (real estate consulting firm)

Robert S. Jepson, Jr., 65
Chairman and Chief Executive Officer,
Jepson Associates, Inc. (private investments)

Mark J. Kington, 48
Managing Director,
X-10 Capital Management, LLC (investments)

Benjamin J. Lambert, III, 71
Optometrist

Margaret A. McKenna, 62
President,
The Wal-Mart Foundation

Frank S. Royal, M.D., 68
Physician

David A. Wollard, 70
Founding Chairman of the Board,
Emeritus, Exempla Healthcare

Executive Officers

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Thomas N. Chewning, 62
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Eva Teig Hardy, 63
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Public Policy & Corporate Communications

Jay L. Johnson, 61
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Chief Executive Officer,
Dominion Virginia Power

Paul D. Koonce, 48
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Mark F. McGettrick, 50
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David A. Christian, 53
President and Chief Nuclear Officer,
Dominion Nuclear

Mary C. Doswell, 49
Senior Vice President,
Regulation and Integrated Planning

G. Scott Hetzer, 51
Senior Vice President and Treasurer

Steven A. Rogers, 46
Senior Vice President and Chief Administrative Officer
President and Chief Administrative Officer,
Dominion Resources Services

James F. Stutts, 63
Senior Vice President and General Counsel

Thomas P. Wohlfarth, 47
Senior Vice President and Chief Accounting Officer

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)
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Major press releases and other company information may be obtained by visiting our Web site at www.dom.com. Shareholders also may obtain account-specific information by visiting this site. To sign up for this service, visit www.dom.com and 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."

Common Stock Listing

New York Stock Exchange
Trading symbol: D

Common Stock Price Range*

	2007		2006	
	High	Low	High	Low
First Quarter	**$44.71**	**$39.84**	$40.21	$34.44
Second Quarter	**46.82**	**40.03**	38.01	34.36
Third Quarter	**46.00**	**40.76**	40.71	37.22
Fourth Quarter	**49.38**	**42.23**	42.22	38.02
Year	**$49.38**	**$39.84**	$42.22	$34.36

**All per-share stock prices reflect the November 2007 2-for-1 stock split.*

Dividends on Dominion common stock are paid as declared by the board. 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.

On December 31, 2007, there were approximately 154,000 registered shareholders, including approximately 62,000 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 2007 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 its Annual Report on Form 10-K for the year ended December 31, 2007.

Annual Meeting

This year's Annual Meeting of Shareholders of Dominion Resources, Inc. will be held Friday, May 9, at 9:30 a.m. (CT) at 1400 S. Lake Shore Drive, Chicago, Illinois.

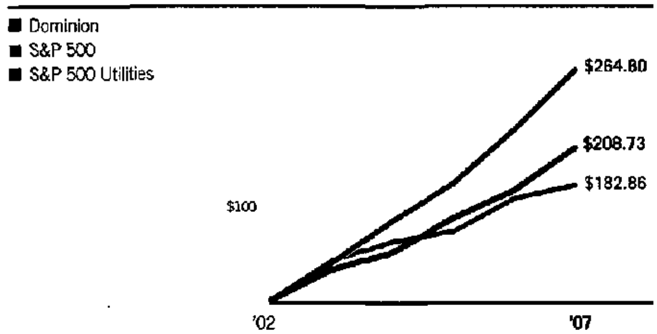
Performance Graph

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	2002	2003	2004	2005	2006	2007
Dominion	100	121.41	134.16	158.54	178.44	**208.73**
S&P 500	100	128.68	142.69	149.70	173.34	**182.86**
S&P 500 Utilities	100	126.26	156.91	183.34	221.82	**264.80**

COMPARISON OF CUMULATIVE FIVE YEAR TOTAL RETURN



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.

Mixed Sources
Product group from well-managed forests, controlled sources and recycled wood or fiber
FSC
www.fsc.org Cert no. SW-COC-1530
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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.

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Dominion Resources

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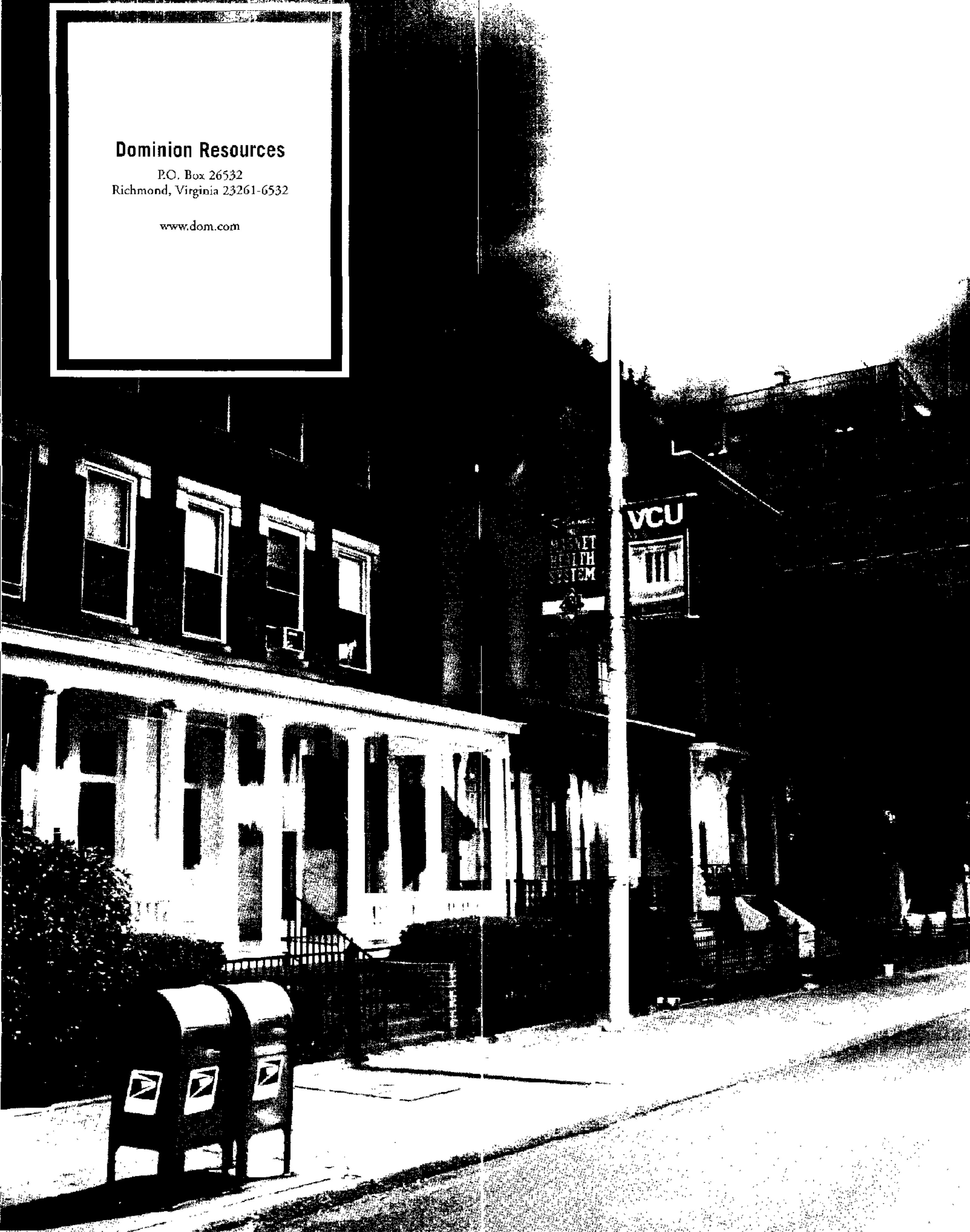
www.dom.com



RENEWAL APPLICATION OF DOMINION RETAIL, INC. ("DOMINION RETAIL") FOR CERTIFICATION BY THE PUBLIC UTILITIES COMMISSION OF OHIO AS A RETAIL NATURAL GAS SUPPLIER

Exhibit C-2 "SEC Filings"

Enclosed herewith, please find an original and ten copies of the most recent 10-K and 8-K filings of parent company Dominion Resources, Inc. Website references to those same filings are noted below.

2007 10-K filing:
http://www.sec.gov/Archives/edgar/data/715957/000119312508041046/0001193125-08-041046-index.htm

2008 8-K filing:
http://www.sec.gov/Archives/edgar/data/715957/000119312508134396/d8k.htm

Exhibit C-2

10kWIZARD
SEC POWER SEARCH

FORM 10-K

DOMINION RESOURCES INC /VA/ - D

Filed: February 28, 2008 (period: December 31, 2007)

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

Table of Contents

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, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number 001-08489

DOMINION 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 ☐ Smaller reporting company ☐
(Do not check if a 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 $24.5 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, 2008, Dominion had 574,841,692 shares of common stock outstanding.

DOCUMENT INCORPORATED BY REFERENCE.

(a)Portions of the 2008 Proxy Statement are incorporated by reference in Part III.

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 United States (U.S.). Our portfolio of assets includes approximately 26,500 megawatts (Mw) of generation, 6,000 miles of electric transmission lines, 55,000 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 1.1 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 billion cubic feet (bcf) of storage capacity and serves retail energy customers in eleven states. On June 30, 2007, we merged our wholly-owned subsidiary, Consolidated Natural Gas Company (CNG) with our holding company, Dominion. As a result of the merger, all of CNG's subsidiaries became direct subsidiaries of Dominion.

We completed the sale of our non-Appalachian natural gas and oil exploration and production (E&P) operations during the third quarter of 2007. We chose to retain our Appalachian assets due to their strategic fit with our natural gas transmission and storage assets.

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.

Following the sale of our non-Appalachian E&P operations, 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) and The East Ohio Gas Company (Dominion East Ohio). 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, 2007, Virginia Power served approximately 2.4 million retail customer accounts, including governmental agencies, as well as, wholesale customers such as rural electric cooperatives and municipalities. 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 gas and oil in the Appalachian basin of the U.S.

As of December 31, 2007, 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 *Dispositions* under *Significant Developments*. We also operate a liquefied natural gas (LNG) import and storage facility in Maryland. Our producer services operations involve the aggregation of natural gas supply and related wholesale activities. We also have nonregulated retail energy marketing operations that include the marketing of gas, electricity and related products and services to residential and small commercial customers. As of December 31, 2007, our retail energy marketing businesses served approximately 1.6 million residential and commercial customer accounts in the Northeast, mid-Atlantic and Midwest regions of the U.S.

As of December 31, 2007, we had approximately 17,000 full-time employees. Approximately 6,500 employees are subject to collective bargaining agreements.

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

Where You Can Find More Information About Dominion

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

Our website address is www.dom.com. We make available, free of charge through our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports as soon as practicable after filing or furnishing the material 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.

Significant Developments

Following are significant acquisitions and divestitures during the last five years as well as a discussion of a November 2007 stock split.

Acquisitions

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 included in our former Dominion E&P operating segment. Following the disposition of these, and all of our other non-Appalachian E&P operations during 2007, and the realignment of our business units in the fourth quarter of 2007, the historical results of these operations are now included in our Corporate and Other segment.

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.

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 in Salem Massachusetts; and the 432 Mw Manchester Street power station in Providence, Rhode Island. The operations of these facilities are included in our Dominion Generation operating segment.

Dispositions

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. At December 31, 2006, our non-Appalachian natural gas and oil assets included about 5.5 Tcfe of proved reserves. A more detailed description of the 2007 disposition of our non-Appalachian E&P operations and assets can be found in Note 6 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.

In December 2004, we sold the majority of our natural gas and oil assets in British Columbia, Canada for $476 million.

The results of these divested operations were formerly included in our Dominion E&P segment; however, following the realignment of our business units in the fourth quarter of 2007, the historical results of these operations are now included in our Corporate and Other segment.

Sale of Merchant Facilities

In March 2007, we sold three of our natural gas-fired merchant generation peaking facilities (Peaker facilities) for net cash proceeds of $254 million. The Peaker facilities include 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 merchant generation facility to AEP Generating Company for $85 million.

Planned Sales

In addition to the completed acquisitions and divestitures above, in March 2006, we entered into an agreement with Equitable Resources, Inc. (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. 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 are seeking other offers for the purchase of these utilities. These operations were included in our former Dominion Delivery operating segment, however following the realignment of our business units in the fourth quarter of 2007, the results of these operations are now included in our Corporate and Other segment.

Common Stock Split

In October 2007, our board of directors approved an increase in the number of shares of common stock the Company is authorized to issue from 500 million to 1 billion and in November 2007, we distributed a two-for-one stock split. All historical share and dividend information presented within this report reflects the impact of the common stock split.

Operating Segments

Prior to a fourth quarter 2007 segment realignment, we managed our daily operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion E&P. During the fourth quarter of 2007, we realigned our business units to reflect our strategic refocusing and began managing our daily operations through three primary operating segments: Dominion Virginia Power (DVP), Dominion Generation and Dominion Energy. 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 6 to our Consolidated Financial Statements. 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 29 to our Consolidated Financial Statements. For additional information on operating revenue related to our principal products and services, see Note 8 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. Actual revenues are driven primarily by weather, customer growth and usage per customer. 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.

Revenue provided by our electric transmission operations is based primarily on rates approved by the Federal Energy Regulatory Commission (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 results from changes in rates, the demand for services, which is primarily weather dependent, and operating and maintenance expenditures. We are a member of PJM Interconnection, LLC (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) as we move toward the future.

Our nonregulated 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 100 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 generation 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 strong growth in new customers and increased usage per customer

on a weather-normalized basis. Growth is particularly strong in the major metropolitan areas of Virginia. The combination of higher energy usage and efficient operations and maintenance spending has been critical to our performance. Operationally, we continue to enhance the customer experience through solid reliability performance and by completing the automation of all of our electric residential meters.

Regulation

DVP's electric retail service, including the rates it may charge to jurisdictional customers, is subject to regulation by the Virginia State Corporation Commission (Virginia Commission) and the North Carolina Utilities Commission (North Carolina Commission). See *Regulation—State Regulations—Electric* for additional information. 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, through the RTEP process, authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects. The first project is an approximately 270-mile 500-kV transmission line from southwestern Pennsylvania to northern Virginia, of which we will construct approximately 65 miles in Virginia and a subsidiary of Allegheny Energy, Inc. (Trans-Allegheny Interstate Line Company) will construct the remainder. This project is estimated to cost approximately $243 million and 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. This project is estimated to cost $180 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 will be subject to applicable state and federal permits and approvals.

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

Sources of Energy Supply

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

Seasonality

DVP's earnings vary seasonally as a result of the impact of changes in temperature on demand by residential and commercial customers for electricity, to meet cooling and heating needs, and gas, to meet heating needs.

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 our producer services business, which aggregates gas supply, provides market-based services related to gas transportation and storage and engages in associated gas trading and marketing.

The gas transmission pipeline and storage business serves Dominion's 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. The profitability of these businesses is dependent on our ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability in earnings results from changes in rates and the demand for services, which can be dependent on weather, changes in commodity prices and changes in the cost of routine maintenance and repairs (including labor and benefits).

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 Public Utilities Commission of Ohio (Ohio Commission). The profitability of this business is dependent on its ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability in earnings relates largely to changes in volumes of natural gas transported, which are weather sensitive, and changes in the cost of routine maintenance and repairs (including labor and benefits).

Our Appalachian natural gas 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 agreements discussed in Note 13 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. We manage commodity price volatility by hedging a substantial portion of our expected production. These hedging activities may require cash deposits to satisfy collateral requirements. Our Appalachian natural gas E&P business added 72.5 bcfe to its gas and oil reserves as a result of its drilling program during 2007, as compared to production of 42.1 bcfe in 2007, 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.

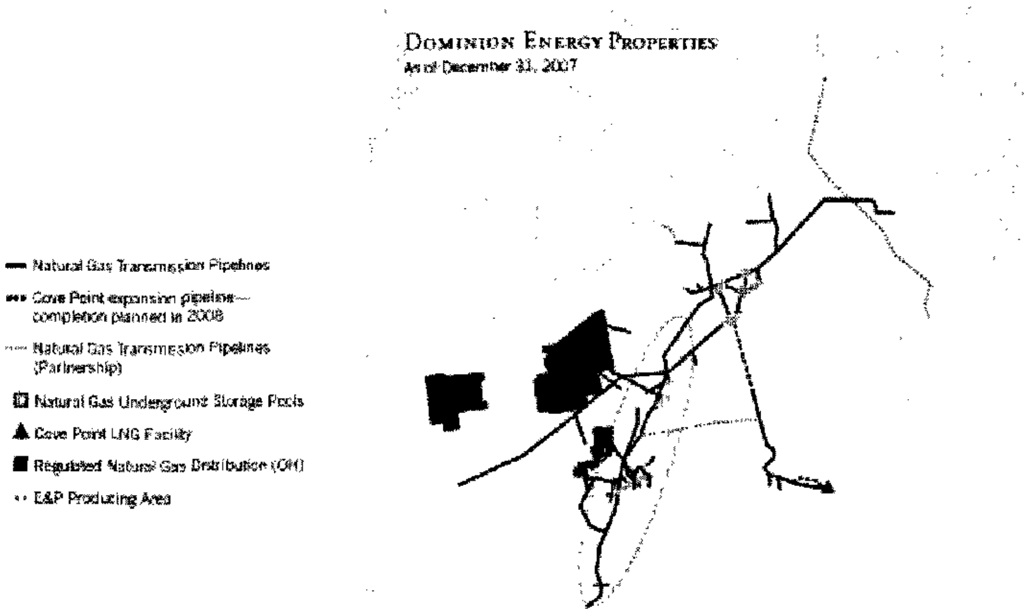
Properties

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 10,300 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 more than 2,000 storage wells and approximately 343,000 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 aboveground storage capacity at its Cove Point LNG facility. Dominion Energy has about 114 compressor stations with more than 670,000 installed compressor horsepower.

Dominion Energy also owns about 1.1 Tcfe of natural gas and oil reserves and produces approximately 124 million cubic feet equivalent of natural gas and oil per day from its leasehold acreage and facility investments in Appalachia.



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. 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 generation mix is diversified and includes coal, nuclear, gas, oil, renewables and purchased power. The generation facilities of our electric utility fleet are located in Virginia, West

Virginia and North Carolina. The generation facilities of our merchant fleet are located in Connecticut, Illinois, Indiana, Massachusetts, Pennsylvania, Rhode Island, West Virginia and Wisconsin. As discussed in *Properties*, we have plans to add additional generation capacity to satisfy future growth in demand.

Dominion Generation's earnings primarily result from the sale of electricity we generate. Due to 1999 Virginia deregulation legislation, as amended in 2004 and 2007, revenues for serving Virginia jurisdictional retail load are 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 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 rate caps in effect through December 31, 2008. During the remainder of the capped rate period, changes in our utility operating costs relative to costs used to establish capped rates, will likely impact our earnings.

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

Competition

Retail choice has been available for Dominion Generation's Virginia jurisdictional electric utility customers since January 1, 2003; however, to date, competition in Virginia has not developed to any significant extent. 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*. 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. The output from these facilities is primarily 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 remaining merchant assets operate within functioning RTOs. Competitors include other generating assets bidding to operate within the RTOs. These RTOs have clearly identified market rules that ensure the competitive wholesale market is functioning properly. Dominion Generation's merchant units have a variety of short and medium-term contracts, and also compete in the spot market with other generators to sell a variety of products including energy, capacity and operating reserves. It is difficult to compare various types of generation given the wide range of fuels, fuel procurement strategies, efficiencies and operating characteristics of the fleet within any given RTO. However, we apply our expertise in operations, dispatch and risk management to maximize the degree to which our merchant fleet is competitive compared to similar assets within the region.

Regulation

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

Properties

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

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 April 2007, we filed an application with the Virginia Commission requesting approval to add two 150 Mw natural gas-fired electric generating units (Units 3 and 4) to our Ladysmith power station (Ladysmith) to supply electricity during periods of peak demand. The Virginia Commission approved the application in August 2007, and construction has commenced. In December 2007, we received approval from the North Carolina Commission for a related affiliate transaction. The facility is expected to be in operation by August 2008, at an estimated cost of $135 million.

In November 2007, we filed an application with the Virginia Commission for approval to add a fifth combustion turbine (Unit 5) at Ladysmith at an estimated cost of $79 million.

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. We also requested approval to continue to accrue an allowance for funds used during construction until capped rates end and, beginning January 1, 2009, receive current recovery of financing costs including a return on common equity of 11.75% together with a 200 basis point enhancement through a rate adjustment clause. An evidentiary hearing was held in February 2008. 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. Pending regulatory approval and necessary permits, the facility is expected to be in operation by 2012 at an estimated capital cost of approximately $1.8 billion.

Also in February 2008, we announced the proposed conversion of our Bremo power station (Bremo) from coal to natural gas as part of our plan to build the Virginia City Hybrid Energy

Center. The proposal is contingent upon the Virginia Hybrid Energy Center entering service and receiving approvals from the Virginia Commission and Virginia Department of Environmental Quality. The proposed conversion project is part of our overall effort to reduce air emissions. Subject to applicable regulatory approvals, the conversion would occur within two years of the Virginia City Hybrid Energy Center entering service.

We are considering the construction of a third nuclear unit within the next twenty years at a site located at the 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) for a site located at North Anna. Also in November 2007, we, along with ODEC filed an application with the NRC for a Combined Construction Permit and Operating License (COL), 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. We have a cooperative agreement with the DOE to share equally the cost of the COL. We have not yet committed to building a new unit.

In December 2007, we announced an agreement to purchase a power station development project in Buckingham County, Virginia that will generate about 600 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 be required to be constructed to provide gas supply to the power station. Pending a closing under the purchase agreement and the receipt of regulatory approval, we plan to build a combined cycle unit with operations expected to begin in summer 2011.

In addition to the *Powering Virginia* projects, we have invested in two 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 construction phases totaling 264 Mw. The first phase (164 Mw) is expected to become fully operational by June 2008 and the second phase is expected to be fully operational by December 2008.

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. The facility is expected to be built in two phases and generate a total of 750 Mw. We will jointly own 650 Mw with BP and BP will retain sole ownership of 100 Mw. We have committed to contribute approximately $340 million of cash at various dates through January 2009, which includes our initial investment and funding for the development of the first 300 Mw phase. Construction of the second 350 Mw phase could begin as early as 2009, with funding to be contributed to the joint venture to maintain 50/50 ownership between the partners. Our ultimate funding requirements may decrease to the extent that the joint venture obtains non-recourse construction and term financing.

Sources of Energy Supply

Dominion Generation uses a variety of fuels to power our electric generation including procuring purchased power for system load requirements, as described below.

Nuclear Fuel—Dominion Generation primarily utilizes long-term contracts to support its nuclear fuel requirements. Some of these agreements have fixed commitments and are included as contractual obligations in *Future Cash Payments for Contractual Obligations and Planned Capital Expenditures* in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A). Worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices which are dependent on the market environment. Current agreements, inventories and spot market availability are expected to support current and planned fuel supply needs for the near term. 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 on demand by residential and commercial customers to meet cooling and heating needs. Sales of electricity from our merchant generation plants are also affected by seasonal changes in demand and commodity prices.

Nuclear Decommissioning

Dominion Generation has a total of seven licensed, operating nuclear reactors at its Surry power station (Surry) and North Anna power station in Virginia, Millstone power station (Millstone) in Connecticut and Kewaunee power station 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 16 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. We believe that the amounts currently available in our decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units, without any additional contributions to those trusts.

The total estimated cost to decommission our eight nuclear units is $4.2 billion in 2007 dollars and is primarily based upon site-specific studies completed in 2006. For all units except Millstone Unit 1 and Unit 2, the current cost estimates assume decommissioning activities will begin shortly after cessation of

operations, which will occur when the operating licenses expire. Millstone Unit 1 is not in service and selected minor decommissioning activities are being performed. This unit will continue to be monitored until full decommissioning activities begin for the remaining Millstone units. We expect to start minor decommissioning activities at Millstone Unit 2 in 2035, with full decommissioning of Millstone Units 1, 2 and 3 during the period 2045 to 2059. We expect to decommission the Surry and North Anna units during the period 2032 to 2059. We intend to apply for a 20-year life extension in 2008 for our Kewaunee unit. If the NRC approves the life extension application, we expect to decommission Kewaunee during the period 2033 to 2059. The license expiration dates for our units are shown in the following table.

	Surry		North Anna		Millstone			Kewaunee	
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2	Unit 3	Unit 1	Total
(dollars in millions)									
NRC license expiration year	2032	2033	2038	2040	(1)	2035	2045	2013	
Most recent cost estimate (2007 dollars)	$ 471	$ 499	$ 449	$ 471	$ 632	$ 534	$ 542	$ 602	$ 4,200
Funds in trusts at December 31, 2007	374	369	306	290	317	374	367	491	2,888
2007 contributions to trusts	1.4	1.5	1.0	0.9	—	—	—	—	4.8

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

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 Dominion Capital, Inc. (DCI), and the net impact of certain operations disposed of or to be disposed of, which are discussed in Note 6 to our Consolidated Financial Statements. Operations disposed of during 2007 included all of our non-Appalachian E&P operations, three natural gas-fired merchant generation peaking facilities and certain DCI operations. Operations to be disposed of include two regulated gas distribution subsidiaries, Peoples and Hope, which we agreed to sell to Equitable in March 2006. However, as previously discussed, this agreement was terminated in January 2008 and we are seeking other offers for the purchase of these utilities. 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

Dominion is 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 efficiency;
- 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 critical role in meeting the growing demand for electricity. Virginia re-regulation legislation enacted in 2007 provides for 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. We announced plans in September 2007 for a series of pilot programs focused on energy conservation and demand response.

The pilots will be offered to a selection of 4,550 customers in our central, eastern and northern Virginia service areas. To help ensure that the results are representative, customers will not be able to volunteer for the pilots nor participate in more than one pilot. We will report results from the pilots at least quarterly to the Virginia Commission staff to help evaluate their effectiveness.

The pilots approved by the Virginia Commission include:

- 1,000 residential customers in each of four different energy-saving pilots. The pilots are designed to cycle central heating and 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 homes will receive energy efficiency welcome kits that include compact fluorescent light bulbs.

- 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 would be in addition to existing Dominion options in which commercial and industrial customers have reduced demand by more than 300 Mw during peak-demand periods.

Renewable energy is also an important component of a diverse and reliable energy mix. Both Virginia and North Carolina have passed legislation setting goals 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. In addition, Dominion is a 50% owner of a wind energy facility in Grant County, West Virginia. When operational, our share of this project will produce 132 Mw of renewable energy. Dominion has also acquired a 50% interest in a joint venture with BP Alternative Energy, Inc. (BP) to develop a wind-turbine facility in Benton County, Indiana. The facility is expected to be built in two phases and generate a total of 750 Mw of which we will jointly own 650 Mw with BP. See *Dominion Generation–Properties* for more information.

We also anticipate using up to 20% biomass (woodwaste) at the proposed Virginia City Hybrid Energy Center discussed in *Dominion Generation–Properties*.

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. The new generation planned in connection with this program is discussed further under *Dominion Generation–Properties*. 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) emissions 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 separation and sequestration. There is no current economically viable technological solution to retro-fit existing fossil-fueled technology to capture and sequester greenhouse gas emissions. Given that new generation units have useful lives of up to 50 years, we will give full consideration to CO_2 and other greenhouse gas emissions when making long-term investment decisions.

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.

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 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 Restructuring Act and Fuel Factor Amendments

On July 1, 2007, legislation amending the Virginia Electric Utility Restructuring Act (the Restructuring Act) and the fuel factor became effective, which significantly changes electricity regulation in Virginia.

Prior to the Restructuring Act, our base rates in Virginia were capped at 1999 levels until December 31, 2010. The Restructuring Act ends capped rates two years early, on December 31, 2008. After capped rates end, retail choice will be eliminated for all but 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 be permitted to purchase renewable energy from competitive suppliers if the incumbent electric utility does not offer a renewable energy tariff. Also after the end of capped rates, the Virginia Commission will set our base rates under a modified cost-of-service model. Among other features, the new model provides for the Virginia Commission to:

- Initiate a base rate case during the first six months of 2009, reviewing the 2008 test year, as a result of which the Virginia Commission:
  - shall establish a return on equity (ROE) no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earnings more than 50 basis points below the established ROE; or
  - may reduce rates prospectively upon completion of the 2009 review or, alternatively, order a credit to customers if we are found to have test year earnings of more than 50 basis points above the established ROE.

- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - shall establish an ROE no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - after 2010, authorize an increased ROE on overall rate base upon achieving the goals established for the renewable energy portfolio standard programs. Such increased ROE would be in lieu of any increased or decreased ROE from the preceding paragraph, unless there has been an increase to the ROE awarded under the preceding paragraph that is higher than the renewable energy portfolio standard increase; and
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earned, during the test period, more than 50 basis points below the then currently established ROE; or
  - may order a credit to customers if we are found to have earned, during the test period, more than 50 basis points above the then currently established ROE, and reduce rates if we are found to have such excess earnings during two consecutive biennial review periods.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service and energy efficiency, conservation and renewable energy programs; and
- Authorize an enhanced ROE on new capital expenditures as a financial incentive for construction of certain major generation projects.

The legislation 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.*

As discussed previously, the legislation provides for the Virginia Commission to initiate a base rate case during the first six months of 2009, as a result of which the Virginia Commission may reduce rates or alternatively, order a credit to customers if we are found to have earnings more than 50 basis points above the established 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.

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 have increased considerably since 2004, 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 on 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. Under these amendments, our fuel factor increase as of July 1, 2007 was limited to an amount that results 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 to be deferred and subsequently recovered subject to Virginia Commission approval, without interest, during the period commencing July 1, 2008 and ending June 30, 2011.

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 change under annual fuel cost adjustment proceedings.

Gas

Our gas distribution services are regulated by the Ohio Commission, the Pennsylvania Public Utility Commission (Pennsylvania Commission) and the Public Services Commission of West Virginia (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, 2007, approximately 820,000 of our 1.2 million Ohio customers were participating in this Energy Choice program. Large industrial customers in Ohio also source their own natural gas supplies. In May 2006, the Ohio Commission approved a two-year pilot program to improve and expand our Energy Choice Program through a Standard Service Offer (SSO) rate. Under the previous structure, non-Energy Choice customers purchased gas directly from us at a monthly gas cost recovery rate that included true-up adjustments that could change significantly from one quarter to the next. In August 2006, the Ohio Commission approved an auction that enabled us to enter into gas purchase contracts with selected suppliers at a fixed price above the New York Mercantile Exchange month-end settlement. This SSO pricing mechanism, implemented in October 2006, replaces the traditional gas cost recovery rate with a monthly market price that eliminates the true-up adjustment, making it easier for customers to compare and switch to competitive suppliers by the end of the transition period. In December 2007, Dominion East Ohio filed an application seeking approval of Phase 2 of its plan to restructure its commodity service, whereby the company will still buy natural gas for Energy Choice-eligible customers currently receiving SSO service, but will identify the customer's designated supplier on the bill. 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.

Pennsylvania—In Pennsylvania, supplier choice is available for all residential and small commercial customers. At December 31, 2007, approximately 95,000 residential and small commercial customers had opted for Energy Choice in our Pennsylvania service area. Nearly all Pennsylvania industrial and large commercial customers buy natural gas from nonregulated suppliers.

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

Rates

Our gas distribution subsidiaries are subject to regulation of rates and other aspects of their businesses by the states in which they operate—Pennsylvania, Ohio and West Virginia. When necessary, our gas distribution subsidiaries seek general base rate increases to recover increased operating costs. 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 over $73 million to provide a rate of return on rate base of 8.72%.

In February 2008, Dominion East Ohio filed an application seeking approval from the Ohio Commission to implement a 25-year program to replace approximately 19% of its 21,000-mile pipeline system and to recover the resulting costs. The application also requests Ohio Commission approval for Dominion East Ohio to assume responsibility for the service lines that run from the curb to the customer's meter. Currently, customers own those service lines and are responsible for bearing the cost of installation and for any repairs or replacement that may be needed.

The cost of the program in total will exceed $2.6 billion in 2007 dollars. The resulting expenditure of more than $100 million per year will more than double Dominion East Ohio's current annual spending on its pipeline infrastructure. However, the cost to customers would be spread out over many decades due to the 25-year time frame of the replacement program and the period over which recovery in rates would be allowed.

Dominion East Ohio also made a related filing asking the Ohio Commission to consolidate its review of the pipeline infrastructure replacement program with Dominion East Ohio's current rate case application in order to give the Ohio Commission and other parties the opportunity to consider the two filings together.

In addition to general rate increases, our gas distribution subsidiaries make routine separate filings with their respective state regulatory commissions to reflect changes in the costs of purchased gas. These purchased gas costs are subject to rate recovery through a mechanism that ensures dollar for dollar recovery of prudently incurred costs. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The purchased gas cost recovery filings generally cover prospective one, three or twelve-month periods. Approved increases or decreases in gas cost recovery rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

Federal Regulations

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 greenhouse gases. 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 500kV, 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. We cannot predict the outcome of the appeal.

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

EPACT included provisions to create an Electric Reliability Organization (ERO). The ERO is required to promulgate mandatory reliability standards governing the operation of the bulk power system in the U.S. In 2006, FERC certified 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 on June 4, 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.

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 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 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 are subject to FERC approval.

In June 2006, we filed a general rate proceeding for DCP. The rates established in this case took effect on January 1, 2007. This rate proceeding enabled DCP to update the cost of service underlying its rates, including recovery of costs associated with the 2002 to 2003 reactivation of the LNG import terminal. The FERC-approved settlement established a rate moratorium that ends in mid-2011.

We implemented various other rate filings, tariff changes and negotiated rate service agreements for our FERC-regulated businesses during 2007. In all material respects, these filings were approved by FERC in the form requested by us and were subject to only minor modifications.

Environmental Regulations

Each of our operating segments faces substantial 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 Dominion. 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 24 to our Consolidated Financial Statements.

The Clean Air Act (CAA) is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. At a minimum, states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of our facilities are subject to the CAA's permitting and other requirements. For example, the EPA has established the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules, when implemented, will require significant reductions in sulfur dioxide (SO_2), nitrogen oxide (NOx) and mercury emissions from electric generating facilities. States are currently developing implementation plans, which will determine the levels and timing of required emission reductions in each of the states within which we own and operate affected generating facilities. Separate from CAIR and CAMR, Massachusetts has regulations specifically targeting reductions in NO_X, SO_2, CO_2 and mercury emissions from our affected facilities in Massachusetts. In February 2008, the U.S. Court of Appeals for the District of Columbia issued a ruling that vacates CAMR as promulgated by the EPA. At this time we cannot determine if this ruling will be subject to further appeals and how the EPA, and subsequently the states, may alter their approach to reducing mercury emissions. We also cannot estimate at this time the impact that this ruling will have on our future capital expenditures.

Based on the increasing intensity of national and international studies regarding climate change and its relationship to greenhouse gas emissions, we expect that there may be federal legislative or regulatory action in this area in the future.

The outcome in terms of specific requirements and timing is uncertain but may include a greenhouse gas emissions cap-and-trade program or a carbon tax for electric generators and natural gas businesses. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate greenhouse gas emissions, which could result in future EPA action. In June 2007, the President announced U.S. support for an effort to develop a new post-2012 framework on climate change involving the top ten to fifteen greenhouse gas emitting countries that would focus on establishing a long-term global goal to reduce greenhouse gas emissions with each country establishing its own mid-term targets and programs. In addition to possible federal action, some states in which we operate have already or may adopt greenhouse gas emission reduction programs. For example, Massachusetts has implemented regulations requiring reductions in CO_2 emissions. The Virginia Energy Plan, released by the Governor of Virginia in September 2007, includes a goal of reducing greenhouse gas emissions statewide back to 2000 levels by 2025. The Governor has formed a Commission on Climate Change to develop a plan to achieve this goal. Until this goal results in legislative or regulatory action, the outcome in terms of specific requirements, timing and cost of compliance is uncertain.

The Clean Water Act (CWA) is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. We must comply with all aspects of the CWA programs at our operating facilities. Provisions under CWA section 316b also include requirements that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. Additional programs under the CWA address the impact of thermal discharges to surface waters.

In October 2003, the EPA and the Massachusetts Department of Environmental Protection (MADEP) each issued new National Pollutant Discharge Elimination System (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. Brayton Point's state appeal will be dismissed upon MADEP finalizing the process for implementing the parallel state permit. Currently, we estimate the total cost to install these cooling towers at approximately $500 million, of which $176 million is included in our planned capital expenditures through 2010.

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 24 to our Consolidated Financial Statements.

From time to time we may be identified as a potentially responsible party (PRP) to a Superfund site. Refer to Note 24 to our Consolidated Financial Statements for a description of our exposure relating to identification as a PRP. We do not believe that any currently identified sites will result in significant liabilities.

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

Nuclear Regulatory Commission

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

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

The NRC also requires us to decontaminate our nuclear facilities once operations cease. This process is referred to as decommissioning, and we are required by the NRC to be financially prepared. For information on our decommissioning trusts, see *Dominion Generation—Nuclear Decommissioning* and Note 12 to our Consolidated Financial Statements.

Item 1A. Risk Factors

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

Our operations are weather sensitive. Our results of operations can be affected by changes in the weather. Weather conditions directly influence the demand for electricity and natural gas, and affect the price of energy commodities. In addition, severe weather, including hurricanes and winter storms, can be destructive, causing outages and property damage that require us to incur additional expenses. In addition, 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 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 position, 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 carbon dioxide 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 carbon dioxide 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 greenhouse gas 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 improvements in the commercial availability and cost of carbon capture and sequestration technology. There are also potential impacts on our natural gas businesses as federal greenhouse gas legislation may require greenhouse gas emission reduction requirements from the natural gas sector. Several regions of the U.S. have moved forward with greenhouse gas regulations including regions where we have operations. For example, Massachusetts has implemented regulations requiring reductions in carbon dioxide emissions and the Regional Greenhouse Gas Initiative, a cap and trade program covering carbon dioxide emissions from power plants in the Northeast, will affect several of our facilities. In addition, a number of bills have been introduced in Congress that would require greenhouse gas 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 greenhouse gas emission reduction requirements may require us to commit significant capital toward carbon capture and sequestration technology, purchase of allowances and/or offsets, fuel switching, and/or retirement of high-emitting generation facilities and replacement with lower emitting generation facilities. The costs of compliance with expected greenhouse gas legislation are 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 sequestration 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.

We are exposed to cost-recovery shortfalls because of capped base rates for our regulated electric utility. Under the Restructuring Act, as amended in 2004 and 2007, our base rates remain capped through December 31, 2008. Although the Restructuring Act allows for the recovery of certain generation-related costs during the capped rates period, we remain exposed to numerous risks of cost-recovery shortfalls, such as costs related to hurricanes or other unanticipated events.

The rates of our Virginia electric utility are subject to regulatory review. As a result of the Restructuring 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 structures, as reviewed and approved in regulatory proceedings. Under the Restructuring 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 have earnings during a 2008 test period which are more than 50 basis points above a return on equity level to be established by the Virginia Commission in that proceeding. After the initial rate case, the Virginia Commission will review the rates of our electric utility company biennially and may order a credit to customers if it is deemed to have earned more than 50 basis points above a return on equity 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 return on equity level during two consecutive biennial review periods.

Energy conservation could negatively impact our financial results. A number of regulatory and legislative bodies have introduced requirements and/or incentives to reduce energy consumption by certain dates. Conservation programs could impact our financial results in different ways. 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 as well as our ability to find buyers willing to enter into power purchase agreements at prices sufficient to cover operating costs. We attempt to manage these risks by entering into both short-term and long-term fixed price sales and purchase contracts and locating our assets in active wholesale energy markets. However, high fuel and commodity costs and excess capacity in the industry could adversely impact our results of operations.

There are risks associated with the operation of nuclear facilities. We operate nuclear facilities that are subject to risks, including the threat of terrorist attack and 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 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 the counterparty fails to perform under a contract. In the absence of actively-quoted market prices and pricing information from external sources, the valuation of these contracts involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

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

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

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

For additional information concerning derivatives and commodity-based trading contracts, see *Market Risk Sensitive Instruments and Risk Management* in Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Notes 2 and 10 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 plant construction and expansion 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 plant construction or expansion 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 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 plant construction and expansion projects may be higher than anticipated and the performance of our business following the plant construction and expansion projects may not meet expectations. Additionally, regulators may disallow recovery of some of the costs of a plant or expansion project if they are deemed not to be prudently incurred. 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 liquidity for capital requirements and collateral requirements, related to hedges of future sales of merchant generation and gas and oil production, not satisfied by the cash flows from our operations. Management believes that Dominion and Virginia Power will maintain sufficient access to these financial markets based upon current credit ratings. However, certain disruptions outside of our control may increase our cost of borrowing or restrict our ability to access one or more financial markets. Such disruptions could include an economic downturn, the bankruptcy of an unrelated energy company or changes to our credit ratings. Restrictions on our ability to access financial markets may affect our ability to execute our business plan as scheduled.

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 projected 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 we are unable to successfully manage the

decommissioning trust funds and benefit plan assets, our results of operation and financial position could be negatively affected.

Changing rating agency requirements could negatively affect our growth and business strategy. As of February 1, 2008, Dominion's senior unsecured debt is rated A-, stable outlook, by Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies, Inc. (Standard & Poor's); Baa2, stable outlook, by Moody's Investors Services (Moody's); and BBB+, stable outlook, by Fitch Ratings Ltd. (Fitch). In order to maintain our current credit ratings in light of existing or future requirements, we may find it necessary to take steps or change our business plans in ways that may adversely affect our growth and earnings per share. A reduction in Dominion's credit ratings or the credit ratings of our Virginia Power 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 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, 2007, we owned our principal executive office and two 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 mortgage securing its First and Refunding Mortgage Bonds. Although there are no publicly issued bonds outstanding as of December 31, 2007, we may issue additional 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,	2007		2006		2005	
	Proved Developed	Total Proved	Proved Developed	Total Proved	Proved Developed	Total Proved
Proved gas reserves (bcf)						
U.S.	636	1,019	3,424	4,961	3,605	4,856
Canada	—	—	132	175	101	106
Total proved gas reserves	636	1,019	3,556	5,136	3,706	4,962
Proved oil reserves (000 bbl)						
U.S.	12,613	12,613	173,718	216,849	145,735	198,602
Canada	—	—	7,061	15,410	7,154	19,096
Total proved oil reserves	12,613	12,613	180,779	232,259	152,889	217,698
Total proved gas and oil reserves (bcfe)	712	1,095	4,640	6,530	4,623	6,268

bbl = barrel
bcfe = billion cubic feet equivalent

Certain of our subsidiaries file Form EIA-23 with the DOE which reports gross proved reserves, including the working interest shares of other owners, for properties operated by such subsidiaries. The proved reserves reported in the 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, 2007 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,	2007	2006	2005
Gas production (bcf)			
U.S.	206	302	275
Canada	8	16	15
Total gas production	214	318	290
Oil production (000 bbl)			
U.S.	11,626	23,923	14,714
Canada	559	1,024	861
Total oil production	12,185	24,947	15,575
Total gas and oil production (bcfe)	287	467	383

The average realized price per thousand cubic feet (mcf) of gas with hedging results (including transfers to other Dominion operations at market prices) during the years 2007, 2006 and 2005 was $5.99, $4.41 and $4.79, respectively. The respective average realized prices without hedging results per mcf of gas produced were $6.63, $6.67 and $8.01. The respective average realized prices for oil with hedging results were $37.78, $33.42 and $30.46 per barrel and the respective average realized prices without hedging results were $50.08, $54.49 and $49.48 per barrel. The average production (lifting) cost per mcf equivalent of gas and oil produced (as calculated per SEC guidelines) during the years 2007, 2006 and 2005 was $1.39, $1.18 and $1.16, respectively.

Acreage

Gross and net developed acreage (in thousands) at December 31, 2007 were 1,367 and 1,281 acres, respectively. Gross and net undeveloped acreage (in thousands) at December 31, 2007 were 376 and 223 acres, respectively.

Net Wells Drilled in the Calendar Year

The number of net wells completed follows:

Year Ended December 31,	*2007*	*2006*	*2005*
Exploratory:			
U.S.			
Productive	—	6	6
Dry	—	3	6
Total U.S.	—	9	12
Canada			
Productive	—	33	—
Dry	—	4	—
Total Canada	—	37	—
Total Exploratory	—	46	12
Development:			
U.S.			
Productive	**804**	1,039	909
Dry	10	33	34
Total U.S.	**814**	1,072	943
Canada			
Productive	**10**	31	59
Dry	—	4	5
Total Canada	**10**	35	64
Total Development	824	1,107	1,007
Total wells drilled (net):	824	1,153	1,019

As of December 31, 2007, 62 gross (57 net) wells were in the process of being drilled, including wells temporarily suspended.

Productive Wells

At December 31, 2007, our subsidiaries had an interest in 9,048 and 8,288 productive gas wells, gross and net, respectively. Our subsidiaries did not have an interest in any productive oil wells at December 31, 2007.

The number of productive wells includes 1 gross (0.89 net) multiple completion gas well and no multiple completion oil wells. Wells with multiple completions are counted only once for productive well count purposes.

POWER GENERATION

We generate electricity for sale on a wholesale and a retail level. We can supply electricity demand either from our generation facilities or through purchased power contracts, when needed. The following table lists Dominion Generation's generating units and capability, as of December 31, 2007:

Plant	Location	Primary Fuel Type	Net Summer Capability (Mw)
Utility Generation			
North Anna	Mineral, VA	Nuclear	1,596(a)
Surry	Surry, VA	Nuclear	1,598
Mt. Storm	Mt. Storm, WV	Coal	1,560
Chesterfield	Chester, VA	Coal	1,253
Chesapeake	Chesapeake, VA	Coal	595
Clover	Clover, VA	Coal	433(b)
Yorktown	Yorktown, VA	Coal	323
Bremo	Bremo Bluff, VA	Coal	227
Mecklenburg	Clarksville, VA	Coal	138
North Branch	Bayard, WV	Coal	74
Altavista	Altavista, VA	Coal	63
Polyester(c)	Hopewell, VA	Coal	63
Southampton	Southampton, VA	Coal	63
Yorktown	Yorktown, VA	Oil	818
Possum Point	Dumfries, VA	Oil	786
Gravel Neck (CT)	Surry, VA	Oil	186
Darbytown (CT)	Richmond, VA	Oil	156
Chesapeake (CT)	Chesapeake, VA	Oil	115
Possum Point (CT)	Dumfries, VA	Oil	72
Northern Neck (CT)	Lively, VA	Oil	47
Low Moor (CT)	Covington, VA	Oil	48
Kitty Hawk (CT)	Kitty Hawk, NC	Oil	32
Remington (CT)	Remington, VA	Gas	582
Possum Point (CC)	Dumfries, VA	Gas	532
Chesterfield (CC)	Chester, VA	Gas	397
Possum Point	Dumfries, VA	Gas	312
Elizabeth River (CT)	Chesapeake, VA	Gas	300
Ladysmith (CT)	Ladysmith, VA	Gas	297
Bellmeade (CC)	Richmond, VA	Gas	232
Gordonsville Energy (CC)	Gordonsville, VA	Gas	218
Rosemary (CC)	Roanoke Rapids, NC	Gas	165
Gravel Neck (CT)	Surry, VA	Gas	158
Darbytown (CT)	Richmond, VA	Gas	156
Bath County	Warm Springs, VA	Hydro	1,706(d)
Gaston	Roanoke Rapids, NC	Hydro	225
Roanoke Rapids	Roanoke Rapids, NC	Hydro	99
Pittsylvania	Hurt, VA	Biomass	83
Other	Various	Various	15
			15,723
Power Purchase Agreements			2,076
Total Utility Generation			17,799
Merchant Generation			
Millstone	Waterford, CT	Nuclear	1,951(e)
Kewaunee	Kewaunee, WI	Nuclear	556
Kincaid	Kincaid, IL	Coal	1,158(f)
Brayton Point	Somerset, MA	Coal	1,122
State Line	Hammond, IN	Coal	515
Salem Harbor	Salem, MA	Coal	314
Morgantown	Morgantown, WV	Coal	25(f),(g)
Brayton Point	Somerset, MA	Oil	438
Salem Harbor	Salem, MA	Oil	440
Fairless (CC)	Fairless Hills, PA	Gas	1,076(h)
Elwood (CT)	Elwood, IL	Gas	712(f),(i)
Manchester (CC)	Providence, RI	Gas	432
Other	Various	Various	17
Total Merchant Generation			8,756
Total Capacity			26,555

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

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

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

(c) Previously referred to as Hopewell.

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

(e) Excludes 6.53% undivided interest in Unit 3 owned by Massachusetts Municipal Wholesale Electric Company and Central Vermont Public Service Corporation.

(f) Subject to a lien securing the facility's debt.

(g) Excludes 50% partnership interest owned by Cogen Technologies Morgantown, Ltd. and Hickory Power Corporation.

(h) Includes generating units that we operate under leasing arrangements.

(i) Excludes 49.9% membership interest owned by J. POWER Elwood, LLC and 0.1% membership interest owned by Peoples Elwood LLC.

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 24 to our Consolidated Financial Statements for additional information on various environmental, rate matters and other regulatory proceedings to which we are a party.

In April 1998, Harrold E. (Gene) Wright filed suit against DEPI (formerly known as CNG Producing Company), a subsidiary of the former CNG, and numerous other companies under the False Claims Act. Mr. Wright alleged various fraudulent valuation practices in the payment of royalties due under federal oil and gas leases. A substantial portion of the claim against us was resolved by settlement in late 2002. The case was remanded back to the U.S. District Court for the Eastern District of Texas, which denied our motion to dismiss on jurisdictional grounds in January 2005. In February 2007, the Judge issued an order providing that trials will occur in phases on 25% of each defendant's leases to be selected by the opposing party. The phase I trial (currently involving another defendant) will commence in August 2008. A phase II trial will occur in February 2009 against two defendants selected by the opposing party, with subsequent phases of trials occurring against other defendants in the future with up to two defendants at each future trial.

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, 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. Brayton Point's state appeal will be dismissed upon MADEP finalizing the process for implementing the parallel state permit. Currently, we estimate the total cost to install these cooling towers at approximately $500 million, of which $176 million is included in our planned capital expenditures through 2010.

In December 2006 and January 2007, we submitted self-disclosure notifications to EPA Region 8 regarding three E&P facilities in Utah that have potentially violated CAA permitting requirements. On July 31, 2007, a third party purchased Dominion's E&P assets in Utah, including these facilities, and under the purchase and sale agreement the third-party assumed responsibility for the resolution of any enforcement action or Consent Decree, including penalties.

In March 2006, Peoples and Equitable filed a joint petition with the Pennsylvania Commission seeking approval of the purchase by Equitable of all of the stock of Peoples and Hope. In April 2006, Hope and Equitable filed a joint petition seeking West Virginia Commission approval of the purchase by Equitable of all of the stock of Hope. In April 2007, the Pennsylvania Commission approved a joint settlement approving the sale in Pennsylvania. Following the approval of the sale of Peoples by the Pennsylvania Commission, the FTC filed an action in federal court seeking to block the transaction. Such action was denied and the case was appealed by the FTC in the 3rd U.S. Circuit Court of Appeals. In January 2008, Dominion and Equitable agreed to terminate their sale agreement. Following that termination, the FTC dismissed its administrative complaint challenging the transaction. In February 2008, the federal appeals court granted a motion by the FTC to dismiss the case and to vacate the district court ruling.

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 (53)	Chairman of the Board of Directors of Dominion Resources, Inc. (DRI) from April 2007 to date; President and Chief Executive Officer (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 from January 2004 to December 2005; President and COO of CNG from January 2004 to December 2005; Executive Vice President of DRI from March 1999 to December 2003; President and CEO of VP from December 2002 to December 2003; Executive Vice President of CNG from January 2000 to December 2003.
Thomas N. Chewning (62)	Executive Vice President and Chief Financial Officer (CFO) of DRI from May 1999 to date; Executive Vice President and CFO of CNG from January 2000 to June 2007; Executive Vice President and CFO of VP from February 2006 to date.
Eva Teig Hardy (63)	Executive Vice President—Public Policy & Corporate Communications of DRI from October 2007 to date; Executive Vice President—External Affairs & Corporate Communications of DRI from January 2007 to September 2007 and of CNG from January 2007 to June 2007; Senior Vice President—External Affairs & Corporate Communications of DRI from May 1999 to December 2006 and of CNG from January 2000 to December 2006.
Jay L. Johnson (61)	Executive Vice President of DRI from December 2002 to date and of CNG from December 2002 to June 2007; President and COO—Dominion Virginia Power of VP from October 2007 to date; President and COO—Delivery of VP from February 2006 to September 2007; President and CEO of VP from December 2002 to January 2006.
Paul D. Koonce (48)	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; CEO—Transmission of VP from January 2003 to December 2003.
Mark F. McGettrick (50)	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 (53)	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.
Mary C. Doswell (49)	Senior Vice President—Regulation and Integrated Planning of DRI, VP and Dominion Resources Services, Inc. (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; President of DRS from January 2003 to December 2003.
G. Scott Hetzer (51)	Senior Vice President and Treasurer of DRI from May 1999 to date; Senior Vice President and Treasurer of VP from January 2000 to date and of CNG from January 2000 to June 2007.
Steven A. Rogers (46)	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 (63)	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 (47)	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; Director of Investor Relations of DRS from February 2000 to December 2003.

(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, 2007, there were approximately 154,000 registered shareholders, including approximately 62,000 certificate holders. Restrictions on our payment of dividends are discussed in Note 22 to our Consolidated Financial Statements. Quarterly information concerning stock prices and dividends is disclosed in Note 31 to our Consolidated Financial Statements.

During 2007, we issued 248 shares of common stock to a former employee as a deferred payment under a 1985 performance achievement plan. These shares were not registered under the Securities Act of 1933 (Securities Act). The issuance of this stock did not involve a public offering, and is therefore exempt from registration under the Securities Act.

The following table presents certain information with respect to our common stock repurchases during the fourth quarter of 2007.

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
10/1/07 – 10/31/07	51,400	$ 43.14	N/A	53,971,148 shares/$2.68 billion
11/1/07 – 11/30/07	15,988	$ 45.79	N/A	53,971,148 shares/$2.68 billion
12/1/07 – 12/31/07	7,562	$ 47.28	N/A	53,971,148 shares/$2.68 billion
Total	74,950	$ 44.12(2)	N/A	53,971,148 shares/$2.68 billion

(1) Amount includes 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 2007.

Item 6. Selected Financial Data

Year Ended December 31,	2007(1)	2006(2)	2005(3)	2004(4)	2003(5)
(millions, except per share amounts)					
Operating revenue	$15,674	$16,297	$17,809	$13,675	$11,802
Income from continuing operations before extraordinary item and cumulative effect of changes in accounting principles	2,705	1,530	1,033	1,255	908
Income (loss) from discontinued operations, net of tax(6)	(8)	(150)	6	(6)	(601)
Extraordinary item, net of tax	(158)	—	—	—	—
Cumulative effect of changes in accounting principles, net of tax	—	—	(6)	—	11
Net income	2,539	1,380	1,033	1,249	318
Income from continuing operations before cumulative effect of changes in accounting principles per common share—basic	4.15	2.19	1.51	1.91	1.43
Net income per common share—basic	3.90	1.97	1.51	1.90	0.50
Income from continuing operations before cumulative effect of changes in accounting principles per common share—diluted	4.13	2.17	1.50	1.90	1.42
Net income per common share—diluted	3.88	1.96	1.50	1.89	0.50
Dividends paid per share	1.46	1.38	1.34	1.30	1.29
Total assets	39,123	49,269	52,660	45,418	43,546
Long-term debt	13,235	14,791	14,653	15,507	15,776

(1) Includes a $1.5 billion after-tax net income benefit from the disposition of our non-Appalachian E&P operations as discussed in Note 6 to our Consolidated Financial Statements. Also includes a $252 million after-tax impairment charge associated with the sale of our partially-completed Dresden Energy merchant generation facility and a $158 million after-tax extraordinary charge resulting from the reapplication of Statement of Financial Accounting Standards (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 our 515 Mw State Line power station.

(2) Includes a $164 million after-tax impairment charge related to three of our natural gas-fired merchant generation peaking facilities (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 two of our regulated gas distribution subsidiaries. See Note 6 to our Consolidated Financial Statements.

(3) 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. See Note 3 to our Consolidated Financial Statements.

(4) 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.

(5) Includes $122 million of after-tax incremental restoration expenses associated with Hurricane Isabel. Also in 2003, we adopted SFAS No. 143, Accounting for Asset Retirement Obligations, Emerging Issues Task Force Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, Statement 133 Implementation Issue No. C20, Interpretation of the Meaning of 'Not Clearly and Closely Related' in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature, and Financial Accounting Standards Board Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities (FIN 46R), which resulted in the recognition of the cumulative effect of changes in accounting principles.

(6) 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 6 to our Consolidated Financial Statements.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) discusses our results of operations and general financial condition. MD&A should be read in conjunction with our Consolidated Financial Statements 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
- Introduction
- Accounting Matters
- Results of Operations
- Segment Results of Operations
- Selected Information—Energy Trading Activities
- Liquidity and Capital Resources
- Future Issues and Other Matters

Forward-Looking Statements

This report contains statements concerning our expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. In most cases, the reader can identify these forward-looking statements by such words as "anticipate," "estimate," "forecast," "expect," "believe," "should," "could," "plan," "may," "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, 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 regional transmission organizations (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;
- The inability to complete planned construction projects within the terms and time frames initially anticipated; and
- Completing the divestiture of the Peoples Natural Gas Company (Peoples) and Hope Gas, Inc. (Hope), and the disposition of investments held by our financial services subsidiary, Dominion Capital, Inc. (DCI).

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

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

Introduction

Dominion, headquartered in Richmond, Virginia, 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 United States (U.S.). Our portfolio of assets includes approximately:

- 26,500 megawatts (Mw) of generation capacity;
- 14,000 miles of interstate natural gas transmission, gathering and storage pipeline;
- 6,000 miles of electric transmission lines;
- 55,000 miles of electric distribution lines in Virginia and North Carolina;
- 28,000 miles of gas distribution pipeline, exclusive of service lines of two inches in diameter or less;
- 1.1 trillion cubic feet equivalent (Tcfe) of proved gas and oil reserves; and
- An underground natural gas storage system with over 975 billion cubic feet (bcf) of capacity.

Prior to a fourth quarter 2007 segment realignment, we managed our daily operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion Exploration and Production (E&P). During the fourth quarter of 2007, we realigned our business units to reflect our strategic refocusing and began managing our daily operations through three primary operating segments: Dominion Virginia Power (DVP), Dominion Generation and Dominion Energy. 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. While we manage our daily operations through our operating segments as described below, our assets remain wholly-owned by our legal subsidiaries.

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

DVP includes our regulated electric transmission, distribution and customer service operations, as well as our nonregulated retail energy marketing operations. Electric transmission and distribution operations serve residential, commercial, industrial and governmental customers in Virginia and northeastern North Carolina. Retail energy marketing operations include the marketing of gas, electricity and related products and services to residential and small commercial customers in the Northeast, mid-Atlantic and Midwest.

Revenue provided by our electric transmission operations is based primarily on rates approved by the Federal Energy Regulatory Commission (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 results from changes in rates, the demand for services, which is primarily weather dependent, and operating and maintenance expenditures. We are a member of PJM Interconnection, LLC (PJM), an 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, 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) as we move toward the future.

Revenue provided by our electric distribution operations is based primarily on rates established by state regulatory authorities and state law. Actual revenues are driven primarily by weather, customer growth and usage per customer. Operationally, electric distribution continues to focus on improving service levels while striving to reduce costs and link capital 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.

In our electric transmission and distribution operations, we are seeing continued strong growth in new customers and increased usage per customer on a weather-normalized basis. Growth is particularly strong in the major metropolitan areas of Virginia. The combination of higher energy usage and efficient operations and maintenance spending has been critical to our performance. Operationally, we continue to enhance the customer experience through solid reliability performance and by completing the automation of all of our electric residential meters.

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 100 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 generation 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.

Dominion Energy includes our regulated Ohio natural gas distribution company, regulated gas transmission pipeline and storage operations, regulated liquefied natural gas (LNG) operations and our Appalachian natural gas E&P business. Dominion Energy also includes our producer services business, which aggregates gas supply, provides market-based services related to gas transportation and storage and engages in associated gas trading and marketing.

The gas transmission pipeline and storage business serves Dominion's gas distribution businesses and other customers in the Northeast, mid-Atlantic and Midwest. Included in our gas transmission pipeline and storage businesses 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. The profitability of these businesses is dependent on our ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability in earnings results from changes in rates and the demand for services, which can be dependent upon weather, changes in commodity prices, and changes in the cost of routine maintenance and repairs (including labor and benefits).

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 Public Utilities Commission of Ohio (Ohio commission). The profitability of this business is dependent on its ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability in earnings relates largely to changes in volumes of natural gas transported, which are primarily weather sensitive, and changes in the cost of routine maintenance and repairs (including labor and benefits).

Our Appalachian natural gas 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 volumetric production payment (VPP) agreements as discussed in Note 13 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. We manage commodity price volatility by hedging a substantial portion of our expected production. These hedging activities may require cash deposits to satisfy collateral requirements.

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.

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

Dominion Generation's earnings primarily result from the generation and sale of electricity. Due to 1999 Virginia deregulation legislation, as amended in 2004 and 2007, revenues for serving Virginia jurisdictional retail load are 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 instituted beginning July 1, 2007 for our Virginia jurisdictional customers. As discussed in *Status of Electric Regulation in Virginia* under *Future Issues and Other Matters*, 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 rate caps in effect through December 31, 2008. During the remainder of the capped rate period, changes in our utility operating costs relative to costs used to establish capped rates, will likely impact our earnings.

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

Corporate and Other 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 or to be disposed of, which are discussed in Note 6 to our Consolidated Financial Statements. Operations disposed of during 2007 included all of our non-Appalachian E&P operations, three natural gas-fired merchant generation peaking facilities (Peaker facilities) and certain DCI operations. Operations to be disposed of reflect two regulated gas distribution subsidiaries, Peoples and Hope, which we agreed to sell to Equitable Resources, Inc. (Equitable), in March 2006. 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. However, 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 are seeking other offers for the purchase of these utilities.

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 in allocating resources among the segments.

ACCOUNTING MATTERS

Critical Accounting Policies and Estimates

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

Accounting For Derivative Contracts at Fair Value

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

Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, we seek indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, we must estimate prices based on available historical and near-term future price information and use of statistical methods, including regression analysis. For options and contracts with option-like characteristics where pricing information is not available from external sources, we generally use a modified Black-Scholes Model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. We use other option models under special circumstances, including a Spread Approximation Model, when contracts include different commodities or commodity locations and a Swing Option Model, when contracts allow either the buyer or seller the ability to exercise within a range of quantities. For contracts with unique characteristics, we estimate fair value using a discounted cash flow approach deemed appropriate under the circumstances and applied consistently from period to period. If pricing information is not available from external sources, judgment is required to develop the estimates of fair value. For individual contracts, the use of different valuation models or assumptions could have a material effect on a contract's estimated fair value.

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

Use of Estimates in Goodwill Impairment Testing

As of December 31, 2007, we reported $3.5 billion of goodwill in our Consolidated Balance Sheet. A significant portion resulted from the acquisition of the former Consolidated Natural Gas Company (CNG) in 2000.

In April of each year, we test our goodwill for potential impairment, and perform additional tests more frequently if impairment indicators are present and after a portion of goodwill has been allocated to a business which we plan to dispose of. The 2007, 2006 and 2005 annual tests did not result in the recognition of any goodwill impairment, as the estimated fair values of our reporting units exceeded their respective carrying amounts.

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.

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 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 2006, we tested the partially-completed Dresden Energy merchant generation facility (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 will be used in the

Ladysmith expansion project discussed in *Utility Generation Expansion* under *Future Issues and Other Matters*.

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 Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71), to those operations on April 4, 2007, the date the legislation was enacted. The reapplication of SFAS No. 71 to the Virginia jurisdiction of our 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* (SFAS No. 143). In connection with the reapplication or 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 since the recovery of those assets was no longer probable. We currently believe the recovery of our remaining regulatory assets is probable. See Notes 2, 6 and 15 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 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 2007, 2006 and 2005, we recognized $99 million, $109 million and $102 million, respectively, of accretion, and expect to incur $95 million in 2008. 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, 2007, nuclear decommissioning AROs, which are reported in the Dominion Generation segment, totaled $1.5 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, 2007 for our AROs related to nuclear decommissioning would have been $267 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 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 medical cost trend rates are critical assumptions. We determine the expected long-term rates of return on plan assets for pension plans and other postretirement benefit plans by using a combination of:

- Historical return analysis to determine expected future risk premiums;
- Forward-looking return expectations derived from the yield on long-term bonds and the price earnings ratios of major stock market indices;
- Expected inflation and risk-free interest rate assumptions; and
- Investment allocation of plan assets. The strategic target asset allocation for our pension fund is 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.

We develop assumptions, which are then compared to the forecasts of other independent investment advisors to ensure reasonableness. An internal committee selects the final assumptions. We calculated our pension cost using an expected return on plan assets assumption of 8.75% for 2007, 2006 and 2005. We calculated our 2007, 2006 and 2005 other postretirement benefit cost using an expected return on plan assets assumption of 8.00%.

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 6.20% and 6.10%, respectively, in 2007 compared to 5.60% and 5.50%, respectively, in 2006, and 6.00% for both discount rates in 2005. Higher long-term bond yields were the primary reason for the increase in the discount rate from 2006 to 2007. We selected discount rates of 6.60% and 6.50% for determining our December 31, 2007 projected pension and postretirement benefit obligations, respectively.

We establish the medical 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 medical cost trend rate assumption as of December 31, 2007 is 9.00% and is expected to gradually decrease to 5.00% in later years.

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

		Increase in Net Periodic Cost	
	Change in Actuarial Assumption	Pension Benefits	Other Postretirement Benefits
(millions, except percentages)			
Discount rate	(0.25)%	$ 13	$ 5
Rate of return on plan assets	(0.25)%	12	2
Healthcare cost trend rate	1%	N/A	20

In addition to the effects on cost, a 0.25% decrease in the discount rate would increase our projected pension benefit obligation by $117 million and would increase our accumulated postretirement benefit obligation by $43 million at December 31, 2007.

Accounting for Gas and Oil Operations

We follow the full cost method of accounting for gas and oil E&P activities prescribed by the Securities and Exchange Commission (SEC). Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized and subsequently depleted using the units-of-production method. The depletable base of costs includes estimated future costs to be incurred in developing proved gas and oil reserves, as well as capitalized asset retirement costs, net of projected salvage values. Capitalized costs in the depletable base are subject to a ceiling test prescribed by the SEC. The test limits capitalized amounts to a ceiling—the present value of estimated future net revenues to be derived from the production of proved gas and oil reserves, discounted at 10 percent, assuming period-end pricing adjusted for any cash flow hedges in place. We perform the ceiling test quarterly, on a country-by-country basis as applicable, and would recognize asset impairments to the extent that total capitalized costs exceed the ceiling. In addition, gains or losses on the sale or other disposition of gas and oil properties are not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil attributable to a country. In 2007, we recognized gains from the sales of our Canadian and U.S. non-Appalachian E&P businesses. See Note 6 to our Consolidated Financial Statements.

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, 2007 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 30 to our Consolidated Financial Statements.

Income Taxes

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

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 Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). Taking into consideration the uncertainty and judgment involved in the determination and filing of income taxes, FIN 48 establishes standards for recognition and measurement, in financial statements, of positions taken, or expected to be taken, by an entity in its income tax returns. Positions taken by an entity in its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by 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, 2007 we had $407 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, 2007, we had established $23 million of valuation allowances on our deferred tax assets associated with loss carryforwards.

Other

Accounting Standards

During 2007, 2006 and 2005, we were required to adopt several new accounting standards, which are discussed in Note 3 to our Consolidated Financial Statements. See Note 4 to our Consolidated Financial Statements for a discussion of recently issued accounting standards that will be adopted in the future.

RESULTS OF OPERATIONS

Presented below is a summary of our consolidated results:

Year Ended December 31,	2007	$ Change	2006	$ Change	2005
(millions, except EPS)					
Net Income	$2,539	$ 1,159	$1,380	$ 347	$1,033
Diluted earnings per share (EPS)(1)	3.88	1.92	1.96	0.46	1.50

(1)All per share amounts have been adjusted to reflect a two-for-one stock split distributed in November 2007.

Overview

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, effective July 1, 2007, for the Virginia jurisdiction of our utility generation operations, with deferred fuel accounting for over- or under-recoveries of fuel costs. 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 our State Line power station (State Line) and the absence of business interruption insurance revenue received in 2006, associated with Hurricanes Katrina and Rita (2005 hurricanes).

2006 vs. 2005

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

Analysis of Consolidated Operations

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

Year Ended December 31, (millions)	2007	$ Change	2006	$ Change	2005
Operating Revenue	$15,674	$ (623)	$16,297	$ (1,512)	$17,809
Operating Expenses					
Electric fuel and energy purchases	3,511	275	3,236	(1,434)	4,670
Purchased electric capacity	439	(42)	481	(23)	504
Purchased gas	2,766	(171)	2,937	(1,004)	3,941
Other energy-related commodity purchases	252	(770)	1,022	(369)	1,391
Other operations and maintenance	4,854	1,676	3,178	198	2,980
Gain on sale of U.S. non-Appalachian E&P business	(3,635)	(3,635)	—	—	—
Depreciation, depletion and amortization	1,368	(189)	1,557	198	1,359
Other taxes	552	(16)	568	(9)	577
Other income	102	(71)	173	10	163
Interest and related charges	1,175	147	1,028	84	944
Income tax expense	1,783	856	927	354	573
Income (loss) from discontinued operations, net of tax	(8)	142	(150)	(156)	6
Extraordinary item, net of tax benefit	(158)	(158)	—	—	—

An analysis of our results of operations for 2007 compared to 2006 and 2006 compared to 2005 follows.

2007 vs. 2006

Operating Revenue decreased 4% to $15.7 billion, primarily reflecting:

- A $535 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 ($1.4 billion), partially offset by higher realized prices ($880 million);

- 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 Emerging Issues Task Force (EITF) Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (EITF 04-13) in 2006. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense;*

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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). This decrease was offset by a corresponding decrease in *Other energy-related commodity purchases expense*;

- A $273 million decrease reflecting the absence of business interruption insurance revenue received in 2006, associated with the 2005 hurricanes;
- A $222 million decrease in 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. The effect of this net decrease was more than offset by a corresponding decrease in *Purchased gas expense*;
- A $77 million decrease in revenue from sales of gas purchased by E&P operations to facilitate gas transportation and other contracts primarily due to the implementation of EITF 04-13 and a reduction in quantities of purchased gas. This decrease was more than offset by a corresponding decrease in *Purchased gas expense*;
- A $54 million decrease in the sales of emissions allowances held for resale. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*; and
- A $47 million decrease in sales of extracted products due to the sale of our U.S. non-Appalachian E&P business;

These decreases were partially offset by:

- A $593 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 in 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 $511 million increase for merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations ($363 million), including higher capacity revenue associated with new capacity markets in ISO New England and PJM, and increased volumes for fossil operations ($148 million); and
- A $134 million increase in gas sales by retail energy marketing activities due to increased customer accounts ($188 million), partially offset by lower contracted sales prices ($54 million). This increase was largely offset by a corresponding increase in *Purchased gas expense;*
- An $88 million increase in gas transportation and storage revenue primarily attributable to our gas distribution operations due to increased volumes and higher prices; and
- A $68 million increase in electric sales by our retail energy marketing operations due to higher volumes ($31 million) and higher sales prices ($37 million). This increase was more than offset by a corresponding increase in *Electric fuel and energy purchases expense.*

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 8% to $3.5 billion, primarily reflecting the combined effects of:

- A $93 million increase for utility generation operations. The underlying fuel costs, including those subject to deferral accounting, increased by approximately $501 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 $86 million increase for our merchant generation operations primarily due to higher commodity prices and increased fossil fuel consumption; and

- A $72 million increase related to our retail energy marketing operations, as discussed in *Operating Revenue.*

Purchased gas expense decreased 6% to $2.8 billion, primarily due to the following factors:

- A $248 million decrease in costs attributable to gas distribution operations, as discussed in *Operating Revenue*; and

- A $97 million decrease related to E&P operations, as discussed in *Operating Revenue.*

These decreases were partially offset by:

- A $124 million increase associated with retail energy marketing activities, due to higher volumes ($168 million), partially offset by lower prices ($44 million), as discussed in *Operating Revenue*; and

- A $50 million increase associated with our producer services business, due to the net impact of an increase in volumes and lower prices.

Other energy-related commodity purchases expense decreased 75% to $252 million, primarily attributable to the following factors, which are discussed in *Operating Revenue*:

- A $409 million decrease related to E&P operations;

- A $310 million decrease in the cost of nonutility coal sales; and

- A $51 million decrease in the cost of sales of emissions allowances held for resale.

Other operations and maintenance expense increased 53% to $4.9 billion, resulting primarily from:

- 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 as a result of the sale of our U.S. non-Appalachian E&P business;

- A $387 million impairment charge related to the sale of Dresden;

- A $231 million charge related to the termination of a long-term power sales agreement at State Line;

- A $171 million charge primarily due to the termination of VPP agreements as a result of the sale of our U.S. non-Appalachian E&P business. We have retained the repurchased fixed-term overriding royalty interests formerly associated with these agreements;

- 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 medical 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;

- A $54 million increase resulting from litigation-related charges;

- A $48 million increase in bad debt expense for gas distribution operations, primarily related to low income energy assistance programs and an increase in sales volumes. These expenditures are recovered through rates and do not impact our net income;

- A $31 million increase primarily due to the inclusion of certain FTR proceeds in *Electric fuel and energy purchases expense*, beginning July 1, 2007, as a result of the reapplication of deferred fuel accounting for the Virginia jurisdiction. These FTR proceeds are used to offset congestion costs associated with PJM spot market activity incurred by our utility generation operations; and

- A $23 million increase related to outside services for tree trimming and brush removal and other expenses.

These charges were partially offset by the absence of the following 2006 items:

- A $166 million charge related to the write-off of certain regulatory assets in connection with the planned sale of Peoples and Hope; and

- A $60 million charge due to the elimination of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts.

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

Depreciation, depletion and amortization expense (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 14% 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.

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.

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.

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 March 2007.

2006 vs. 2005

Operating Revenue decreased 8% to $16.3 billion, primarily reflecting:

- A $1.0 billion decrease primarily attributable to lower volumes associated with requirements-based power sales contracts that were exited. The effect of this decrease was more than offset by a corresponding decrease in *Electric fuel and energy purchases expense*;

- An $844 million decrease in our producer services business consisting of a decrease in both volumes and prices associated with gas aggregation, partially offset by favorable price changes related to gas marketing activities. The effect of this decrease was partially offset by a corresponding decrease in *Purchased gas expense*;

- A $367 million decrease from gas distribution operations, primarily reflecting a $219 million decrease resulting from the loss of customers to Energy Choice programs and a $270 million decrease associated with milder weather and variations in rates resulting from changes in customer usage patterns, sales mix and other factors, partially offset by a $122 million increase related to the recovery of higher gas prices. The effect of this net decrease was partially offset by a corresponding decrease in *Purchased gas expense*;

- A $308 million decrease in nonutility coal sales, primarily resulting from decreased volumes. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*;

- A $178 million decrease in sales of emissions allowances purchased for resale, reflecting lower prices ($115 million) and lower overall sales volume ($63 million). The effect of this decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*; and
- A $100 million decrease in revenue from sales of gas purchased by E&P operations to facilitate gas transportation and other contracts, primarily due to the impact of netting sales and purchases of gas under buy/sell arrangements associated with the implementation of EITF 04-13.

These decreases were partially offset by:

- A $313 million increase from our merchant generation business, primarily reflecting higher revenue for nuclear operations as a result of higher realized prices and new business from the addition of Kewaunee nuclear power station (Kewaunee), which was acquired in July 2005. This increase was partially offset by lower sales volume for fossil plants driven largely by comparably milder weather and lower prices;

- A $235 million increase associated with hedging activities for our merchant generation assets. The effect of this increase was offset by a corresponding increase in *Other operations and maintenance expense*;

- A $189 million increase in sales of gas and oil production, primarily due to higher volumes ($351 million), partially offset by lower prices ($162 million);

- A $184 million increase in gas sales by our retail energy marketing operations primarily resulting from increased customer counts ($141 million) and higher contracted sales prices ($43 million). This increase was largely offset by a corresponding increase in *Purchased gas expense;*

- A $165 million increase in sales of extracted products, primarily due to increased prices and a contractual change for a portion of our gas production processed by third parties. We now take title to and market the extracted products from this gas;

- An increase of $95 million resulting from higher business interruption insurance revenue received in 2006 related to the 2005 hurricanes ($274 million) versus business interruption insurance revenue received in 2005 ($179 million) related to Hurricane Ivan; and

- An $88 million increase due to a sale of gas inventory by our Ohio gas distribution subsidiary related to the implementation of the Standard Service Offer (SSO) pilot program as approved by the Public Utilities Commission of Ohio. The SSO was initiated to encourage and assist other suppliers to enter the gas procurement market. By the end of the transition period, we plan to exit the gas merchant function in Ohio and have all customers select an alternate gas supplier. The effect of this increase was offset by a comparable increase in *Purchased gas expense.*

Operating Expenses and Other Items

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

- A $1.2 billion decrease associated with lower volumes associated with requirements-based power sales contracts, as discussed in *Operating Revenue;*

- A $162 million decrease for our utility generation operations, primarily due to lower commodity prices, including purchased power, and decreased consumption of fossil fuel, reflecting the effects of milder weather on demand, partially offset by an increase in purchased power volumes; and

- A $104 million decrease from our merchant generation business, due primarily to lower commodity prices and decreased consumption of fossil fuel, reflecting the effects of milder weather on demand, partially offset by higher replacement power costs incurred due to an increase in scheduled outage days.

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

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

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

- A $237 million decrease in the cost of coal purchased for resale; and
- A $175 million decrease in emissions allowances purchased for resale; partially offset by
- A $47 million increase related to purchases of oil by E&P operations, reflecting higher market prices ($63 million), partially offset by lower volumes ($16 million) of oil purchases under buy/sell arrangements.

Other operations and maintenance expense increased 7% to $3.2 billion, resulting from:

- A $235 million increase primarily related to hedging activities associated with our generation assets. The effect of this increase is offset by a corresponding increase in *Operating Revenue*;
- A $166 million charge from the write-off of certain regulatory assets related to the planned sale of Peoples and Hope;
- A $97 million increase resulting primarily from higher salaries, wages and benefits expenses;
- A $93 million increase attributable to higher production handling, transportation and operating costs related to E&P operations;
- $91 million of impairment charges related to DCI investments;
- A $79 million increase resulting from Kewaunee, which was acquired in July 2005;
- A $65 million decrease in gains from the sale of emissions allowances held for consumption;
- A $60 million charge to eliminate the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts that sold trust preferred securities;
- A $41 million reduction in proceeds related to FTRs granted by PJM to our utility generation operations. These FTRs are used to offset congestion costs associated with PJM spot market activity, which are included in *Electric fuel and energy purchases expense*;
-

A $35 million increase in generation-related outage costs primarily due to an increase in the number of scheduled outages;

- A $29 million increase related to major storm damage and service restoration costs associated with our distribution operations, including costs resulting from tropical storm Ernesto in September 2006;
- A $27 million charge resulting from the cancellation of a pipeline project;

These increases were partially offset by:

- A $96 million decrease in hedge ineffectiveness expense associated with our E&P operations, primarily due to a decrease in the fair value differential between the delivery location and commodity specifications of derivative contracts held by us as compared to our forecasted gas and oil sales and the increased use of basis swaps;

- A $62 million benefit resulting from favorable changes in the fair value of certain gas and oil derivatives that were de-designated as hedges following the 2005 hurricanes;

- A benefit resulting from the absence of the following items recognized in 2005:

  - A $423 million loss related to the discontinuance of hedge accounting for certain gas and oil derivatives resulting from an interruption of gas and oil production in the Gulf of Mexico caused by the 2005 hurricanes;

  - A $77 million charge resulting from the termination of a long-term power purchase agreement;

  - A $59 million loss related to the discontinuance of hedge accounting for certain oil derivatives primarily resulting from a delay in reaching anticipated production levels in the Gulf of Mexico, and subsequent changes in the fair value of those derivatives; and

  - A $51 million charge related to credit exposure associated with the bankruptcy of Calpine Corporation; partially offset by

  - A $24 million net benefit resulting from the establishment of certain regulatory assets and liabilities in connection with the settlement of a North Carolina rate case in the first quarter of 2005.

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

Interest expense increased 9% to $1.0 billion principally reflecting the impact of additional borrowings and higher interest rates on variable rate debt.

Loss from discontinued operations was $150 million as compared to income from discontinued operations of $6 million in 2005, primarily due to a $164 million charge related to the Peaker facilities, whose operations were reclassified to discontinued operations in December 2006.

Outlook

Our 2007 results were positively impacted by the gain recognized from the sale of our non-Appalachian E&P business. In 2008, we believe our remaining businesses will provide growth in earnings per share, including the impact of lower expected average shares outstanding. The following are factors that will impact our expected 2008 results:

- A full year of deferred fuel accounting for Virginia jurisdiction fuel costs as compared to six months in 2007;
- Higher margins for our merchant generation fleet;
- Increased production and higher realized prices for our Appalachian E&P operations and fixed-term overriding royalty interests formerly associated with VPP agreements, as discussed in Note 13 to our Consolidated Financial Statements;
- Lower interest expense reflecting a full year's benefit from our debt tender offer completed in July 2007;
- A decrease in outage costs reflecting a decrease in the number of scheduled outage days at certain of our electric utility generating facilities; and
- Continued growth in utility customers.

The increase in 2008 is expected to be partially offset by:

- A potential decrease in regulated electric sales, as compared to 2007, assuming our utility service territory experiences a return to normal weather in 2008; and
- An increase in depreciation expense, partially attributable to revised depreciation rates for our utility generation assets resulting from a new depreciation study implemented in the fourth quarter of 2007.

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,	2007		2006		2005	
	Net Income	Diluted EPS	Net Income	Diluted EPS	Net Income	Diluted EPS
(millions, except EPS)						
DVP	$ 415	$ 0.64	$ 411	$ 0.59	$ 378	$ 0.55
Dominion Energy	387	0.59	347	0.49	362	0.53
Dominion Generation	756	1.15	537	0.76	416	0.60
Primary operating segments	1,558	2.38	1,295	1.84	1,156	1.68
Corporate and Other	981	1.50	85	0.12	(123)	(0.18)
Consolidated	$2,539	$ 3.88	$1,380	$ 1.96	$1,033	$ 1.50

DVP

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

Year Ended December 31,	2007	% Change	2006	% Change	2005
Electricity delivered (million mwhrs)(1)	84.7	6%	79.8	(2)%	81.4
Degree days:					
Cooling(2)	1,794	15	1,557	(9)	1,707
Heating(3)	3,500	10	3,178	(16)	3,784
Average electric distribution customer accounts(4)	2,361	1	2,327	2	2,286
Average retail energy marketing customer accounts(4)	1,551	15	1,354	17	1,162

mwhrs = megawatt hours

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

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

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

(4)Thirteen-month average, in thousands.

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

2007 vs. 2006

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	$ 22	$ 0.03
Customer growth	11	0.02
Major storm damage and service restoration[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.

2006 vs. 2005

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Retail energy marketing operations	$ 57	$ 0.09
Interest expense[1]	10	0.01
Regulated electric sales:		
Weather	(34)	(0.05)
Customer growth	13	0.02
Major storm damage and service restoration[2]	(18)	(0.03)
North Carolina rate case settlement	(6)	(0.01)
Other	11	0.02
Share dilution	—	(0.01)
Change in net income contribution	$ 33	$ 0.04

(1)Principally reflects additional intercompany borrowings and higher interest rates on those borrowings.

(2)Reflects an increase in major storm damage and service restoration expenses including expenses associated with tropical storm Ernesto in September 2006.

Dominion Energy

Presented below are operating statistics related to Dominion Energy's gas transmission and distribution operations:

Year Ended December 31,	2007	% Change	2006	% Change	2005
Gas throughput (bcf):					
Gas sales (distribution)	50	(11)	56	(33)	84
Gas transportation (distribution)	210	9	193	2	190
Gas transportation (transmission)	719	11	650	(18)	794
Heating degree days	5,886	12	5,274	(13)	6,037
Average gas distribution customer accounts[1]:					
Gas sales	410	(15)	485	(25)	643
Gas transportation	800	9	732	27	576

bcf = billion cubic feet

(1)Thirteen-month average, in thousands.

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

Year Ended December 31,	2007	% Change	2006	% Change	2005
Liquids production[1] (bcfe)	57.6	47	39.1	2	38.4
Average realized prices without hedging results:					
Liquids (per mcfe)	$6.55	(8)	$7.11	(14)	$8.31
Average realized prices with hedging results:					
Liquids (per mcfe)	6.55	33	4.93	(2)	5.05
DD&A (per mcfe)	1.68	31	1.28	17	1.09
Average production (lifting) cost (per mcfe)[2]	1.28	8	1.19	1	1.18

bcfe = billion cubic feet equivalent
mcfe = thousand cubic feet equivalent

(1)Includes natural gas, natural gas liquids and oil.

(2)The inclusion of volumes associated with reacquired overriding royalty interests arising from the VPP's terminated in 2007 would have resulted in lifting costs of $1.00 in 2007.

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

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.

2006 vs. 2005

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Interest expense[1]	$ (18)	$ (0.03)
Gas and oil—prices	(17)	(0.02)
Regulated gas sales—weather	(16)	(0.02)
Gas transmission rate reduction[2]	(13)	(0.02)
DD&A – gas and oil	(6)	(0.01)
Gas transmission operations[3]	31	0.04
Producer services[4]	23	0.03
Gas and oil—production	13	0.02
Other	(13)	(0.02)
Share dilution	—	(0.01)
Change in net income contribution	$ (15)	$ (0.04)

(1)Primarily reflects additional intercompany borrowings and higher interest rates on those borrowings.

(2)Due to lower natural gas transportation and storage revenue as a result of a 2005 rate settlement.

(3)Primarily due to higher margins on extracted products and market center service opportunities.

(4)Higher income resulting from the impact of favorable price changes related to price risk management and gas marketing activities associated with certain transportation and storage contracts.

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, 2007, by applicable time period. As of December 31, 2007, we have not hedged any of our anticipated production past 2009.

	Natural Gas	
Year	Hedged production (bcf)	Average hedge price (per mcf)
2008	51.2	$ 8.60
2009	14.6	8.25

Dominion Generation

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

Year Ended December 31,	2007	% Change	2006	% Change	2005
Electricity supplied (million mwhrs):					
Utility	84.7	6%	79.7	(2)%	81.4
Merchant	46.0	11	41.5	1	41.2
Degree days (electric utility service area):					
Cooling	1,794	15	1,557	(9)	1,707
Heating	3,500	10	3,178	(16)	3,784

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

2007 vs. 2006

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Merchant generation margin[1]	$ 211	$ 0.30
Unrecovered 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; this benefit is 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.

2006 vs. 2005

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Merchant generation margin[1]	$ 215	$ 0.32
Unrecovered Virginia fuel expenses	40	0.06
Regulated electric sales:		
Customer growth	24	0.04
Weather	(64)	(0.09)
Sales of emissions allowances	(40)	(0.06)
Energy supply margin[2]	(27)	(0.04)
Outage costs[3]	(20)	(0.03)
Salaries, wages and benefits expense	(13)	(0.02)
2005 North Carolina rate case settlement	(10)	(0.01)
Other	16	0.02
Share dilution	—	(0.03)
Change in net income contribution	$ 121	$ 0.16

(1)Primarily reflects higher realized prices.

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

(3)Primarily due to an increase in the duration of scheduled outage days for both utility and merchant generation operations.

Corporate and Other

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

Year Ended December 31,	2007	2006	2005
(millions, except EPS amounts)			
Specific items attributable to operating segments	$ (618)	$ (10)	$ (133)
Discontinued operations	(8)	(150)	6
Net benefit from sale of U.S. non-Appalachian E&P businesses	1,426	(5)	—
U.S. non-Appalachian E&P divested operations	252	625	163
Peoples and Hope	49	(72)	43
Other corporate operations	(120)	(303)	(202)
Total net benefit (expense)	981	85	(123)
Earnings per share impact	$ 1.50	$0.12	$(0.18)

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 29 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, as well as the increase in the loss for 2006 as compared to 2005, reflects a $164 million after-tax charge in 2006 associated with the impairment of the Peaker facilities that were sold in 2007.

Net Benefit From Sale of U.S. non-Appalachian E&P Business

The net benefit from 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. See Note 6 to our Consolidated Financial Statements for discussion of these items.

U.S. Non-Appalachian E&P Divested 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.

The higher contribution in 2006 as compared to 2005 primarily reflects the absence of a $357 million after-tax loss in 2005 related to the discontinuance of hedge accounting in August and September 2005 for certain gas and oil derivatives resulting from an interruption in gas and oil production in the Gulf of Mexico caused by 2005 hurricanes and subsequent changes in the fair value of those derivatives during the third quarter.

Peoples and Hope

The net loss in 2006 primarily reflects a $104 million after-tax charge resulting from the write-off of certain regulatory assets related to the planned sale of Peoples and Hope.

Other Corporate Operations

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 as described below 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.

The net expenses associated with other corporate operations for 2006 increased by $101 million as compared to 2005, primarily reflecting a $37 million after-tax charge to eliminate the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts and the $85 million impairment of a DCI investment in 2006. The recognition of deferred tax liabilities in 2006 was offset by a reduction in valuation allowances to reflect the expected utilization of federal and state loss carryforwards to offset income that was expected to be generated from the 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 natural gas, electricity, oil and coal. Settlements of contracts may require physical delivery of the underlying commodity or cash settlement. We also enter into contracts with the objective of benefiting from changes in prices. For example, after entering into a contract to purchase a commodity, we typically enter into a sales contract, or a combination of sales contracts, with quantities and delivery or settlement terms that are identical or very similar to those of the purchase contract. When the purchase and sales contracts are settled either by physical delivery of the underlying commodity or by net cash settlement, we may receive a net cash margin (a realized gain), or may pay a net cash margin (a realized loss). We continually monitor our contract positions, considering location and timing of delivery or settlement for each energy commodity in relation to market price activity.

A summary of the changes in the unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes during 2007 follows:

	Amount
(millions)	
Net unrealized gain at December 31, 2006	$ 42
Contracts realized or otherwise settled during the period	(43)
Net unrealized gain at inception of contracts initiated during the period	—
Change in unrealized gains and losses	53

Changes in unrealized gains and losses attributable to changes in valuation techniques	—
Net unrealized gain at December 31, 2007	$ 52

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at December 31, 2007, 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[1]	$39	$ 6	$ 6	$ —	$ —	$ 51
Other external sources[2]	1	—	(2)	1	1	1
Total	$40	$ 6	$ 4	$ 1	$ 1	$ 52

(1)Exchange-traded and over-the-counter contracts.

(2)Values based on prices from over-the-counter broker activity and industry services and, where applicable, conventional option pricing models.

Liquidity and Capital Resources

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

At December 31, 2007, we had $3.0 billion of unused capacity under our credit facilities. See additional discussion under *Credit Facilities and Short-Term Debt.*

A summary of our cash flows is presented below:

	2007	2006	2005
(millions)			
Cash and cash equivalents at beginning of year	$ 142	$ 146	$ 361
Cash flows provided by (used in):			
Operating activities	(246)	4,005	2,623
Investing activities	10,192	(3,494)	(3,360)
Financing activities	(9,801)	(515)	522
Net increase (decrease) in cash and cash equivalents	145	(4)	(215)
Cash and cash equivalents at end of year[1]	$ 287	$ 142	$ 146

(1)2007 and 2006 amounts include $4 million of cash classified as held for sale in our Consolidated Balance Sheets.

Operating Cash Flows

In 2007, net cash provided by operating activities decreased by $4.3 billion as compared to 2006. The decrease primarily reflects income taxes paid on the gain from the sale of a majority of our E&P business, as well as other cash costs associated with the sale, such as gas and oil derivative settlement costs. In addition, cash flow was lower in 2007 as it included only a partial year of cash flow from the E&P operations sold. While taxes and other costs of the sale are reflected in cash flow from operations, the gross proceeds from the sale are 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, 2007 for these activities. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights.

	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
(millions)			
Investment grade[1]	$ 596	$ 98	$ 498
Non-investment grade[2]	13	—	13
No external ratings:			
Internally rated—investment grade[3]	173	5	168
Internally rated—non-investment grade[4]	26	—	26
Total	$ 808	$ 103	$ 705

(1)Designations as investment grade are based upon minimum credit ratings assigned by Moody's Investors Service (Moody's) and Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies, Inc. (Standard & Poor's). The five largest counterparty exposures, combined, for this category represented approximately 32% of the total net credit exposure.

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

(3)The five largest counterparty exposures, combined, for this category represented approximately 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 2007, net cash provided by investing activities was $10.2 billion as compared to net cash used in investing activities of $3.5 billion in 2006. This change primarily reflects proceeds received in 2007 from the sale of a majority of our E&P business.

Financing Cash Flows and Liquidity

We rely on banks and capital markets as significant sources of funding for capital requirements not satisfied by cash provided by the companies' operations. As discussed in *Credit Ratings*, our ability to borrow funds or issue securities and the return demanded by investors are affected by the issuing company's credit ratings. In addition, the raising of external capital is subject to certain regulatory approvals, including registration with the SEC and, in the case of Virginia Electric and Power Company (Virginia Power), approval by the Virginia State Corporation Commission (Virginia Commission).

In December 2005, the SEC adopted the rules that currently govern the registration, communications and offering processes under the Securities Act of 1933. 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 2007, net cash used in financing activities increased by $9.3 billion as compared to 2006. The increase primarily reflects the use of proceeds from the sale of a majority of our E&P business to repurchase our common stock and repay debt.

Credit Facilities And Short-Term Debt

As a result of the merger of CNG with Dominion in June 2007, all of CNG's former credit facilities have been assumed by Dominion. We use short-term debt, primarily commercial paper, to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, we utilize cash and letters of credit to fund collateral requirements under our commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels, our credit quality and the credit quality of our counterparties. Short-term financing is supported by a $3.0 billion five-year joint revolving credit facility with Virginia Power dated February 2006 that terminates in February 2011, and can also be used to support up to $1.5 billion of letters of credit. Short-term financing at Dominion is also supported by an amended and restated $1.7 billion five-year revolving credit facility and a $200 million five-year bilateral credit facility, dated February 2006 and December 2005, respectively, and are scheduled to terminate in August and December 2010, respectively. At December 31, 2007, we had committed lines of credit totaling $4.9 billion. These lines of credit support commercial paper borrowings, bank loans and letter of credit issuances. Our financial policy precludes issuing commercial paper in excess of our supporting lines of credit. At

December 31, 2007, we had the following commercial paper, bank loans and letters of credit outstanding, as well as capacity available under credit facilities:

	Facility Limit	Outstanding Commercial Paper	Outstanding Bank Loans	Outstanding Letters of Credit	Facility Capacity Available
(millions)					
Five-year joint revolving credit facility	$3,000	$ 757	$ —	$ 229	$ 2,014
Five-year Dominion credit facility	1,700	—	1,000	1	699
Five-year Dominion bilateral facility	200	—	—	—	200
Totals	$4,900	$ 757	$ 1,000	$ 230	$ 2,913

In addition to the facilities above, we also entered into a $100 million bilateral credit facility in August 2004 that terminates in August 2009. At December 31, 2007, there were no letters of credit outstanding under this facility.

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.

Long-Term Debt

During 2007 we issued the following long-term debt:

Type	Principal	Rate	Maturity	Issuing Company
	(millions)			
Senior notes	$ 350	6.00%	2017	Dominion
Senior notes	600	6.00%	2037	Virginia Power
Senior notes	600	5.95%	2017	Virginia Power
Senior notes	600	5.10%	2012	Virginia Power
Senior notes	450	6.35%	2037	Virginia Power
Senior revolving notes	75	Variable	2017	DCI
Total long-term debt issued	$ 2,675			

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 a coupon rate of 3.6%. 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, Series 1985 that would otherwise have matured in February 2008.

In November 2007, Virginia Power borrowed $14 million in connection with the Economic Development Authority of the County of Chesterfield's issuance of its Solid Waste and Sewage Disposal Revenue Bonds, Series 2007 A, which mature in 2031 and bear a coupon rate of 5.60%. The bonds were issued pursuant to a trust agreement whereby funds are withdrawn from the trust as improvements are made at our Chesterfield Power Station located in Chester, Virginia. We have withdrawn less than $1 million from the trust as of December 31, 2007.

DCI consolidates a collateralized debt obligation (CDO) entity in accordance with FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R). In August 2007, the CDO entity issued an additional $75 million of senior revolving notes that mature in January 2017 and are nonrecourse to us. At December 31, 2007, outstanding borrowings under this credit facility totaled $75 million.

During 2007, we repaid $5.5 billion of long-term debt and notes payable, which includes the completion of a debt tender offer repurchasing $2.5 billion of our debt securities in July 2007.

Included in the debt repayments above is the redemption of all 8 million units of the $200 million 7.8% Dominion CNG Capital Trust I debentures due October 31, 2041. These securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions. Also included is the redemption of approximately 240 thousand units of the $250 million 8.4% Dominion Capital Trust III debentures due January 15, 2031. These securities were redeemed at a price of $1,209 per preferred security plus accrued and unpaid distributions.

Issuance of Common Stock

In 2007, we received cash proceeds of $226 million for 7.6 million shares issued in connection with the exercise of employee stock options. During 2007, we purchased our common stock on the open market with the proceeds received through Dominion Direct® (a dividend reinvestment and open enrollment direct stock purchase plan) and employee savings plans, rather than having additional new common shares issued. In January 2008, we began issuing additional new common shares to be used for these programs. In 2008, we expect to receive proceeds from these programs of between $200 million to $250 million.

Repurchases of Common Stock

In 2007, we repurchased 129.0 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.

In December 2006, we entered into a prepaid accelerated share repurchase agreement (ASR) with a financial institution as the counterparty. Under the ASR, we would receive between 11.2 million and 13.0 million shares in exchange for the prepayment. At the time of execution of the ASR, we made a prepayment of $500 million and the counterparty initially delivered approximately 10.1 million shares to us. The final number of shares to be delivered to the Company was determined by the volume weighted-average price of our common stock over the period commencing on December 12, 2006 and terminating on May 16, 2007. In May 2007, the counterparty delivered approximately 1.6 million additional shares to us in completion of the ASR.

At December 31, 2007, 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.

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.

Credit ratings for the Dominion Companies as of February 1, 2008 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	BBB+	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, 2008, Fitch Ratings Ltd. (Fitch), Moody's and Standard & Poor's maintain a stable outlook for their ratings of the Dominion Companies.

As a result of the merger of CNG with Dominion in June 2007, all of CNG's former rights and obligations under its indentures have been assumed by Dominion. Subsequent to the merger, Moody's lowered its rating of CNG Senior Unsecured debt from Baa1 to Baa2 to equal their rating of Dominion's Senior Unsecured debt.

In December 2007, Standard & Poor's raised its corporate credit rating on the Dominion Companies to 'A-' from 'BBB' to reflect the companies' lower risk profile. Standard & Poor's also affirmed the 'A-2' commercial paper rating for both 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, 2007, 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%	58%
Virginia Power	65%	47%

(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.

We initially designated the 8.4% Capital Securities of Dominion Resources Capital Trust III as covered debt for purposes of the RCCs. Under the terms of the RCCs, we are required under certain circumstances to change the series of our debt designated as covered debt under the RCCs. Due to our acquisition of most of the designated securities in our debt tender offer in July 2007, they ceased to be eligible as covered debt for the RCCs. In the third quarter of 2007, we designated the September hybrids as covered debt under the June hybrids' RCC and designated the June hybrids as covered debt under the September hybrids' RCC.

We monitor the covenants on a regular basis in order to ensure that events of default will not occur. As of December 31, 2007, there have been no events of default under our debt covenants. Other than the change in covered debt for the RCCs discussed above, as of December 31, 2007, there have been no 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, 2007, 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, 2007.

See Note 19 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, 2007. 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 2008.

	2008	2009 - 2010	2011 - 2012	2013 and thereafter	Total
(millions)					
Long-term debt(1)	$1,478	$1,270	$1,980	$ 10,008	$14,736
Interest payments(2)	805	1,468	1,321	9,659	13,253
Leases	81	130	91	151	453
Purchase obligations(3):					
Purchased electric capacity for utility operations	383	713	700	1,857	3,653
Fuel to be used for utility operations	794	814	566	435	2,609
[illegible]	39	133	178	195	545

Fuel to be used for nonregulated operations					
Pipeline transportation and storage	151	157	84	86	478
Energy commodity purchases for resale[4]	517	44	28	—	589
Other[5]	327	106	31	49	513
Other long-term liabilities[6]:					
Financial derivative-commodities[4]	215	12	—	—	227
Other contractual obligations[7]	52	1	—	—	53
Total cash payments	$4,842	$4,848	$4,979	$ 22,440	$37,109

(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 15, 16 and 23 to the Consolidated Financial Statements. Due to uncertainty about the timing and amounts that will ultimately be paid, $246 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 9 to our Consolidated Financial Statements.

(7)Includes interest rate swap agreements.

PLANNED CAPITAL EXPENDITURES

Our planned capital expenditures are expected to total approximately $3.7 billion in 2008 and approximately $4.1 billion annually in both 2009 and 2010. These expenditures are expected to include construction and expansion of electric generation and LNG facilities 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 *Generation Expansion* in *Future Issues and Other Matters* 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 FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. See Note 24 to our Consolidated Financial Statements for further discussion of these guarantees.

At December 31, 2007, we had issued $41 million of guarantees to support third parties and equity method investees. In addition, in December 2006, we acquired a 50% interest in a joint venture with Shell to develop a wind-turbine facility in Grant County, West Virginia (NedPower). We have issued a limited-scope guarantee and indemnification for one-half of the project-level financing for phase one of the NedPower wind project. Under this guarantee, we would be required to repay 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. The 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 the guarantee totaled $56 million as of December 31, 2007 and will increase to $103 million in 2008 based upon NedPower's future expected borrowings to complete phase one. Shell WindEnergy Inc. has provided an identical guarantee for the other one-half of NedPower's borrowings.

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

Common Stock Split and Dividend Increase

In October 2007, our board of directors approved an increase in the number of shares of common stock the Company is authorized to issue from 500 million to 1 billion and in November 2007 we distributed a two-for-one stock split. All historical share and dividend information presented within this report reflects the impact of the common stock split.

In a separate matter, our board of directors approved an increase in our quarterly common stock dividend rate. The quarterly dividend rate was increased to 39.5 cents per share, an 11% increase over our existing quarterly dividend rate of 35.5 cents per share. Stated as an annual rate, the board's action increases the dividend rate from $1.42 per share to $1.58 per share.

Status of Electric Regulation in Virginia

2007 Virginia Restructuring Act and Fuel Factor Amendments

On July 1, 2007, legislation amending the Virginia Electric Utility Restructuring Act (the Restructuring Act) and the fuel factor became effective, which significantly changes electricity regulation in Virginia. Prior to the Restructuring Act, our base rates in Virginia were capped at 1999 levels until December 31, 2010. The Restructuring Act ends capped rates two years early, on December 31, 2008. After capped rates end, retail choice will be eliminated for all but 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 be permitted to purchase renewable energy from competitive suppliers if the incumbent electric utility does not offer a renewable energy tariff. Also after the end of capped rates, the Virginia Commission will set our base rates under a modified cost-of-service model. Among other features, the new model provides for the Virginia Commission to:

- Initiate a base rate case during the first six months of 2009, reviewing the 2008 test year, as a result of which the Virginia Commission:
  - shall establish a return on equity (ROE) no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earnings more than 50 basis points below the established ROE; or
  - may reduce rates prospectively upon completion of the 2009 review or, alternatively, order a credit to customers if we are found to have test year earnings of more than 50 basis points above the established ROE.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - shall establish an ROE no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - after 2010, authorize an increased ROE on overall rate base upon achieving the goals established for the renewable energy portfolio standard programs. Such increased ROE would be in lieu of any increased or decreased ROE from the preceding paragraph, unless there has been an increase to the ROE awarded under the preceding paragraph that is higher than the renewable energy portfolio standard increase; and
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earned, during the test period, more than 50 basis points

below the then currently established ROE; or

- may order a credit to customers if we are found to have earned, during the test period, more than 50 basis points above the then currently established ROE, and reduce rates if we are found to have such excess earnings during two consecutive biennial review periods.

- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service and energy efficiency, conservation, and renewable energy programs; and
- Authorize an enhanced ROE on new capital expenditures as a financial incentive for construction of certain major generation projects.

The legislation 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.*

As discussed previously, the legislation provides for the Virginia Commission to initiate a base rate case during the first six months of 2009, as a result of which the Virginia Commission may reduce rates or alternatively, order a credit to customers if we are found to have earnings more than 50 basis points above the established 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.

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 have increased considerably since 2004, 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 on 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. Under these amendments, our fuel factor increase as of July 1, 2007 was limited to an amount that results 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 to be deferred and subsequently recovered subject to Virginia Commission approval, without interest, during the period commencing July 1, 2008 and ending June 30, 2011.

North Carolina Regulation

In 2004, the North Carolina Utilities Commission (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 change under the annual fuel cost adjustment proceedings.

Dominion Transmission Inc. (DTI) 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 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 are subject to FERC approval.

Dominion Cove Point Rates

In June 2006, we filed a general rate proceeding for Dominion Cove Point LNG, LP (DCP). The rates established in this case took effect on January 1, 2007. This rate proceeding enabled DCP to update the cost of service underlying its rates, including recovery of costs associated with the 2002 to 2003 reactivation of the LNG import terminal. The FERC-approved settlement established a rate moratorium that ends in mid-2011.

Regional Transmission Expansion Plan

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. The first project is an approximately 270-mile 500-kilovolt (kV) transmission line from southwestern Pennsylvania to northern Virginia, of which we will construct approximately 65 miles in Virginia and a subsidiary of Allegheny Energy, Inc. (Trans-Allegheny Interstate Line Company) will construct the remainder. This project is expected to cost approximately $243 million and 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. This project is estimated to cost $180 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 will be subject to applicable state and federal permits and approvals. In April 2007, we, along with Trans-Allegheny Interstate Line Company, filed an application with the Virginia Commission requesting approval of the proposed construction of the 65-mile transmission line in northern Virginia. In May 2007, we filed an application with the Virginia Commission requesting approval of the proposed construction of the 60-mile transmission line in southeastern Virginia. Evidentiary hearings on these applications commenced in February 2008.

Utility Generation Expansion

Based on available generation capacity and current estimates of growth in customer demand in our utility service area, we will need additional generation 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, multitechnology 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 April 2007, we filed an application with the Virginia Commission requesting approval to add two 150 Mw natural gas-fired electric generating units (Units 3 and 4) to our Ladysmith power station (Ladysmith) to supply electricity during periods of peak demand. The facility is expected to be in operation by August 2008, at an estimated cost of $135 million. The Virginia Commission approved the application in August 2007, and construction has commenced. In December 2007, we received approval from the North Carolina Commission for a related affiliate transaction.

In November 2007, we filed an application with the Virginia Commission for approval to add a fifth combustion turbine (Unit 5) at Ladysmith at an estimated cost of $79 million.

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. We also requested approval to continue to accrue an allowance for funds used during construction until capped rates end and, beginning January 1, 2009, receive current recovery of financing costs including a return on common equity of 11.75% together with a 200 basis point enhancement through a rate adjustment clause. An evidentiary hearing was held in February 2008. 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. Pending regulatory approval and necessary permits, the facility is expected to be in operation by 2012 at an estimated cost of approximately $1.8 billion.

Also in February 2008, we announced the proposed conversion of our Bremo power station (Bremo) from coal to natural gas as part of our plan to build the Virginia City Hybrid Energy Center. The proposal is contingent upon the Virginia Hybrid Energy Center entering service and receiving approvals from the Virginia Commission and Virginia Department of Environmental Quality. The proposed conversion project is part of our overall effort to reduce air emissions. Subject to applicable regulatory approvals, the conversion would occur within two years of the Virginia City Hybrid Energy Center entering service.

We are considering the construction of a third nuclear unit within the next twenty years at a site located at the 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) for a site located at North Anna. Also in November 2007, we, along with ODEC filed an application with the NRC for a Combined Construction Permit and Operating License (COL), 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. We have a cooperative agreement with the Department of Energy to share equally the cost of the COL. We have not yet committed to building a new unit.

In December 2007, we announced an agreement to purchase a power station development project in Buckingham County, Virginia that will generate about 600 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 be required to be constructed to provide gas supply to the power station. Pending a closing under the purchase agreement and the receipt of regulatory approval, we plan to build a combined cycle unit with operations expected to begin in summer 2011.

Wind Power Acquisition

In an effort to foster renewable generation development consistent with our environmental strategy, 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. The facility is expected to be built in two phases and generate a total of 750 Mw. We will jointly own 650 Mw with BP and BP will retain sole ownership of 100 Mw. We have committed to contribute approximately $340 million of cash at various dates through January 2009, which includes our initial investment and funding for the development of the first 300 Mw phase. Construction of the second 350 Mw phase could begin as early as 2009, with funding to be contributed to the joint venture to maintain 50/50 ownership between the partners. Our ultimate funding requirements may decrease to the extent that the joint venture obtains non-recourse construction and term financing.

PJM Rate Design

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 into 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 500kV, 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. We cannot predict the outcome of the appeal.

Ohio Rate Case

In August 2007, The East Ohio Gas Company (Dominion East Ohio) filed an application to increase base rates. In this rate case, Dominion East Ohio requests approval of an increase in operating revenues of over $73 million to provide a rate of return on rate base of 8.72%. As part of its request, Dominion East Ohio is proposing to install automated meter reading devices for all of its 1.2 million customers over a 5-year period and to spend up to an additional $5.5 million per year over a three-year period on demand side management programs if the Ohio Commission approves a decoupling mechanism that would automatically adjust base rates in order to maintain base rate revenues per customer at the level approved in the rate case. In addition, Dominion East Ohio is proposing to expand its gross receipts tax rider to apply to all amounts billed for services, rather than just gas cost recoveries, thereby excluding gross receipts tax from base rates.

In February 2008, Dominion East Ohio filed an application seeking approval from the Ohio Commission to implement a 25-year program to replace approximately 19% of its 21,000-mile pipeline system and to recover the resulting costs. The application also requests Ohio Commission approval for Dominion East Ohio to assume responsibility for the service lines that run from the curb to the customer's meter. Currently, customers own those service lines and are responsible for bearing the cost of installation and for any repairs or replacement that may be needed.

The cost of the program in total will exceed $2.6 billion in 2007 dollars. The resulting expenditure of more than $100 million per year will more than double Dominion East Ohio's current annual spending on its pipeline infrastructure. However, the cost to customers would be spread out over many decades due to the 25-year time frame of the replacement program and the period over which recovery in rates would be allowed.

Dominion East Ohio also made a related filing asking the Ohio Commission to consolidate its review of the pipeline infrastructure replacement program with Dominion East Ohio's current rate case application in order to give the Ohio Commission and other parties the opportunity to consider the two filings together.

Environmental Matters

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

To the extent environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 2008, in excess of the level currently included in Virginia jurisdictional rates, our results of operations could decrease. After that date, we are allowed to seek recovery through rates.

Environmental Protection and Monitoring Expenditures

We incurred approximately $181 million, $138 million and $205 million of expenses (including depreciation) during 2007, 2006 and 2005, respectively, in connection with environmental protection and monitoring activities and expect these expenses to be approximately $218 million and $333 million in 2008 and 2009, respectively. In addition, capital expenditures related to environmental controls were $293 million, $332 million and $140 million for 2007, 2006 and 2005, respectively. These expenditures are expected to be approximately $194 million and $191 million for 2008 and 2009, respectively.

Clean Air Act (CAA) Compliance

In March 2005, the Environmental Protection Agency (EPA) Administrator signed both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules, when implemented, will require significant reductions in sulfur dioxide (SO_2), nitrogen oxide (NOx) and mercury emissions from electric generating facilities. The SO_2 and NOx emission reduction requirements are imposed in two phases, with initial reduction levels targeted for 2009 (NOx) and 2010 (SO_2), and a second phase of reductions targeted for 2015 (SO_2 and NOx). The mercury emission reduction requirements are also in two phases, with initial reduction levels targeted for 2010 and a second phase of reductions targeted for 2018. The federal rules allow for the use of cap-and-trade programs. West Virginia has adopted final regulations for CAIR and CAMR. Virginia has adopted final regulations for CAIR with requirements more strict than the federal rule and will adopt final regulations for CAMR with requirements more strict than the federal rule. Illinois has finalized regulations to implement CAIR and CAMR with requirements more strict than the federal rule. Indiana has adopted CAIR and CAMR, with only minor changes. Massachusetts has finalized regulations to implement CAIR with requirements more strict than the federal rule. Separate from the CAA, CAIR and CAMR, Massachusetts has regulations specifically targeting reductions in NOx, SO_2, and mercury emissions from our affected facilities in Massachusetts. These CAA regulatory and non-CAA state actions will require additional reductions in emissions from our fossil fuel-fired generating facilities and are already addressed in our current compliance planning. In June 2005, the EPA finalized amendments to the Regional Haze Rule, also known as the Clean Air Visibility Rule (CAVR). Although we anticipate that the emission reductions achieved through compliance with CAIR and CAMR will generally address CAVR, we do expect that additional emission reduction requirements will be imposed on several of our merchant facilities. Implementation of projects to comply with these SO_2, NOx and mercury limitations, and other state emission control programs are ongoing and will be influenced by changes in the regulatory environment, availability of emission allowances and emission control technology. In response to these CAA and non-CAA state requirements, we estimate that we will make capital expenditures at our affected generating facilities of approximately $900 million during the period 2008 through 2012. In February 2008, the U.S. Court of Appeals for the District of Columbia issued a ruling that vacates CAMR as promulgated by the EPA. At this time we cannot determine if this ruling will be subject to further appeals and how the EPA, and subsequently the states, may alter their approach to reducing mercury emissions. We also cannot estimate at this time the impact on our future capital expenditures.

Regulation of Greenhouse Gas Emissions

We operate two coal/oil-fired generating power stations in Massachusetts that are already subject to the implementation of carbon dioxide (CO_2) emission regulations issued by the Massachusetts Department of Environmental Protection (MADEP). Additionally, Massachusetts, Rhode Island and Connecticut 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 which are currently in development in these states. We own and operate a gas/oil-fired electric generating facility in Rhode Island that is subject to RGGI, in addition to the two coal/oil-fired stations in Massachusetts. Implementing regulations for RGGI in Massachusetts and Rhode Island have yet to be fully developed. While the cost of complying with the RGGI requirements for the period 2009 to 2011 could adversely affect our results of operations, we cannot provide a reasonable estimate of such cost until the results of the first RGGI allowance auction are conducted later in 2008 and an allowance market develops. Additionally, any such costs of compliance could potentially be mitigated by increases in power prices impacting our affected power stations in the Northeast.

In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate greenhouse gas emissions which could result in future EPA action. In June 2007, the President announced U.S. support for an effort to develop a new post-2012 framework on climate change involving the top ten to fifteen greenhouse gas emitting countries that would focus on establishing a long-term global goal to reduce greenhouse gas emissions with each country establishing its own mid-term targets and programs. In addition to possible federal action, some states in which we operate have already or may adopt greenhouse gas emission reduction programs. For example, Massachusetts has implemented regulations requiring reductions in CO_2 emissions.

The Virginia Energy Plan, released by the Governor of Virginia in September 2007, includes a goal of reducing greenhouse gas emissions statewide back to 2000 levels by 2025. The Governor formed a Commission on Climate Change to develop a plan to achieve this goal. Until this goal results in legislative or regulatory action, the outcome in terms of specific requirements and timing is uncertain. The cost of compliance with future greenhouse gas 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 greenhouse gas reduction programs on our operations or our customers at this time.

Clean Water Act Compliance

In July 2004, the EPA published regulations under the Clean Water Act 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 presents 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. 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 will be held on the draft permit with a Final Determination expected to be issued by the CTDEP within the next year. Until the final permit is reissued, it is not possible to predict the financial impact that may result.

In October 2003, the EPA and MADEP each issued new NPDES permits for the Brayton Point power station (Brayton Point). The new permits contained identical conditions that in effect require the installation of cooling towers to address concerns over the withdrawal and discharge of cooling water. 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. Brayton Point's state appeal will be dismissed upon MADEP finalizing the process for implementing the parallel state permit. Currently, we estimate the total cost to install these cooling towers at approximately $500 million, of which $176 million is included in our planned capital expenditures through 2010.

Future Environmental Regulations

We expect that there may be federal legislative or regulatory action regarding the regulation of greenhouse gas emissions and regarding compliance with more stringent air emission standards in the future. With respect to greenhouse gas emissions, the outcome in terms of specific requirements and timing is uncertain but may include a greenhouse gas emissions cap-and-trade program or a carbon tax for electric generators and natural gas businesses. With respect to emission reductions, specific requirements under consideration would be phased in under periods of up to ten to fifteen years. If any of these new proposals are adopted, additional significant expenditures may be required.

Environmental Strategy

Dominion is 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 efficiency;
- 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 critical role in meeting the growing demand for electricity. Virginia re-regulation legislation enacted in 2007 provides for 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. We announced plans in September 2007 for a series of pilot programs focused on energy conservation and demand response.

The pilots will be offered to a selection of 4,550 customers in our central, eastern and northern Virginia service areas. To help ensure that the results are representative, customers will not be able to volunteer for the pilots nor participate in more than one pilot. We will report results from the pilots at least quarterly to the Virginia Commission staff to help evaluate their effectiveness.

The pilots approved by the Virginia Commission include:

- 1,000 residential customers in each of four different energy-saving pilots. The pilots are designed to cycle central heating and 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 homes will receive energy efficiency welcome kits that include compact fluorescent light bulbs.
- 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 would be in addition to existing Dominion options in which commercial and industrial customers have reduced demand by more than 300 Mw during peak-demand periods.

Renewable energy is also an important component of a diverse and reliable energy mix. Both Virginia and North Carolina have passed legislation setting goals 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. In addition, Dominion is a 50% owner of a wind energy facility in Grant County, West Virginia. When operational, our share of this project will produce 132 Mw of renewable energy. Dominion has also acquired a 50% interest in a joint venture with BP Alternative Energy, Inc. (BP) to develop a wind-turbine facility in Benton County, Indiana. The facility is expected to be built in two phases and generate a total of 750 Mw of which we will jointly own 650 Mw with BP.

We also anticipate using up to 20% biomass (woodwaste) at the proposed Virginia City Hybrid Energy Center.

We have announced a comprehensive generation growth program, referred to as *Powering Virginia*, which involves the development, financing, construction and operation of new multi-fuel, multi-technology generation capacity to meet the growing demand in our core market of Virginia. We expect that these investments collectively will provide the following benefits: expanded electricity production capability; increased technological and fuel diversity; and a reduction in the carbon dioxide emissions 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 separation and sequestration. There is no current economically viable technological solution to retro-fit existing fossil-fueled technology to capture and sequester greenhouse gas emissions. Given that new generation units have useful lives of up to 50 years, we will give full consideration to CO_2 and other greenhouse gas emissions when making long-term investment decisions.

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.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The matters discussed in this Item may contain "forward-looking statements" as described in the introductory paragraphs of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. The reader's attention is directed to those paragraphs and Item 1A. Risk Factors for discussion of various risks and uncertainties that may affect our future.

Market Risk Sensitive Instruments and Risk Management

Our financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates 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 equity price risk through various portfolios of equity securities.

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

Commodity Price Risk

To manage price risk, we 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 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 fair value of commodity-based financial derivative instruments is determined based on models that consider the market prices of commodities in future periods, the volatility of the market prices in each period, as well as the time value factors of the derivative instruments. Prices and volatility are principally determined based on actively-quoted market prices.

A hypothetical 10% unfavorable change in market prices of our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $338 million and $597 million as of December 31, 2007 and 2006, respectively. The decrease is primarily due to the termination of derivatives related to the divestiture of our non-Appalachian E&P business. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $8 million and $3 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of December 31, 2007 and 2006, respectively.

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

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, 2007 and 2006, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $11 million and $25 million, respectively. The decrease is due primarily to a decrease in variable rate debt.

Investment Price Risk

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

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

We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $43 million and $63 million in 2007 and 2006, respectively. In 2007, we recorded unrealized gains on these investments of $52 million to AOCI and regulatory liabilities. We recorded, in AOCI, unrealized gains on these investments of $194 million in 2006.

We also sponsor employee pension and other postretirement benefit plans that hold investments in trusts to fund benefit payments. To the extent that the values of investments held in these trusts decline, the effect will be reflected in our recognition of the periodic cost of such employee benefit plans and the determination of the amount of cash to be contributed to the employee benefit plans. Our pension and other postretirement benefit plan assets generated actual returns of $520 million and $674 million in 2007 and 2006, respectively. As of December 31, 2007, a hypothetical 0.25% decrease in the assumed rates of return on our plan assets would result in an increase in net periodic cost of approximately $12 million for pension benefits and $2 million for other postretirement benefits. As of December 31, 2006, a hypothetical 0.25% decrease in the assumed rates of return on our plan assets would have resulted in an increase in net periodic cost of approximately $11 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, 2007 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, 2007 and 2006, and the related consolidated statements of income, common shareholders' equity and comprehensive income, and of cash flows for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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 uncertain tax positions in 2007, pension and other postretirement benefit plans, share-based payments, and purchases and sales of inventory with the same counterparty in 2006, and conditional asset retirement obligations in 2005.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, 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 26, 2008 expresses an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 26, 2008

Consolidated Statements of Income

Year Ended December 31, (millions, except per share amounts)	2007	2006	2005
Operating Revenue	$15,674	$16,297	$17,809
Operating Expenses			
Electric fuel and energy purchases	3,511	3,236	4,670
Purchased electric capacity	439	481	504
Purchased gas	2,766	2,937	3,941
Other energy-related commodity purchases	252	1,022	1,391
Other operations and maintenance	4,854	3,178	2,980
Gain on sale of U.S. non-Appalachian E&P business	(3,635)	—	—
Depreciation, depletion and amortization	1,368	1,557	1,359
Other taxes	552	568	577
Total operating expenses	10,107	12,979	15,422
Income from operations	5,567	3,318	2,387
Other income	102	173	163
Interest and related charges:			
Interest expense[1]	1,032	888	822
Interest expense—junior subordinated notes payable[2]	127	124	106
Subsidiary preferred dividends	16	16	16
Total interest and related charges	1,175	1,028	944
Income from continuing operations before income tax expense, minority interest, extraordinary item and cumulative effect of change in accounting principle	4,494	2,463	1,606
Income tax expense	1,783	927	573
Minority interest	6	6	—
Income from continuing operations before extraordinary item and cumulative effect of change in accounting principle	2,705	1,530	1,033
Income (loss) from discontinued operations[3]	(8)	(150)	6
Extraordinary item[4]	(158)	—	—
Cumulative effect of change in accounting principle[5]	—	—	(6)
Net Income	$ 2,539	$ 1,380	$ 1,033
Earnings Per Common Share—Basic[6]:			
Income from continuing operations before extraordinary item and cumulative effect of change in *accounting principle*	$ 4.15	$ 2.19	$ 1.51
Income (loss) from discontinued operations	(0.01)	(0.22)	0.01
Extraordinary item	(0.24)	—	—
Cumulative effect of change in accounting principle	—	—	(0.01)
Net income	$ 3.90	$ 1.97	$ 1.51
Earnings Per Common Share—Diluted[6]:			
Income from continuing operations before extraordinary item and cumulative effect of change in accounting principle	$ 4.13	$ 2.17	$ 1.50
Income (loss) from discontinued operations	(0.01)	(0.21)	0.01
Extraordinary item	(0.24)	—	—
Cumulative effect of change in accounting principle	—	—	(0.01)
Net income	$ 3.88	$ 1.96	$ 1.50
Dividends paid per common share	$ 1.46	$ 1.38	$ 1.34

(1) 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.

(2) Includes $73 million, $104 million and $106 million incurred with affiliated trusts in 2007, 2006 and 2005, respectively.

(3) Net of income tax expense (benefit) of $115 million, ($107) million and $13 million in 2007, 2006 and 2005, 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.

(4) Net of income tax benefit of $101 million in 2007.

(5) Net of income tax benefit of $4 million in 2005.

(6) All per share amounts have been adjusted to reflect a two-for-one stock split distributed in November 2007.

Theaccompanying notes are an integral part of our Consolidated Financial Statements.

Consolidated Balance Sheets

At December 31, (millions)	2007	2006
ASSETS		
Current Assets		
Cash and cash equivalents	$ 283	$ 138
Customer receivables (less allowance for doubtful accounts of $37 and $26)	2,130	2,395
Other receivables (less allowance for doubtful accounts of $10 and $13)	226	358
Inventories:		
Materials and supplies	427	429
Fossil fuel	341	383
Gas stored	277	289
Derivative assets	761	1,593
Assets held for sale	1,160	1,391
Prepayments	387	254
Other	664	868
Total current assets	6,656	8,098
Investments		
Nuclear decommissioning trust funds	2,888	2,791
Other	992	1,034
Total investments	3,880	3,825
Property, Plant and Equipment		
Property, plant and equipment	33,331	43,575
Accumulated depreciation, depletion and amortization	(11,979)	(14,193)
Total property, plant and equipment, net	21,352	29,382
Deferred Charges and Other Assets		
Goodwill	3,496	4,298
Pension and other postretirement benefit assets	1,565	1,246
Derivative assets	188	642
Intangible assets	598	628
Regulatory assets	957	539
Other	431	611
Total deferred charges and other assets	7,235	7,964
Total assets	$ 39,123	$ 49,269

At December 31, (millions)	2007	2006
Liabilities and Shareholders' Equity		
Current Liabilities		
Securities due within one year	$ 1,477	$ 2,478
Short-term debt	1,757	2,332
Accounts payable	1,734	2,142
Accrued interest, payroll and taxes	934	759
Derivative liabilities	680	2,276
Liabilities held for sale	492	497
Other	672	745
Total current liabilities	7,746	11,229
Long-Term Debt		
Long-term debt	11,759	12,842
Junior subordinated notes payable to:		
Affiliates	678	1,151
Other	798	798
Total long-term debt	13,235	14,791
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	4,253	5,858
Asset retirement obligations	1,722	1,930
Derivative liabilities	181	681
Regulatory liabilities	1,223	614
Other	1,072	973
Total deferred credits and other liabilities	8,451	10,056
Total liabilities	29,432	36,076
Commitments and Contingencies (see Note 24)		
Minority Interest	28	23
Subsidiary Preferred Stock Not Subject To Mandatory Redemption	257	257
Common Shareholders' Equity		
Common stock—no par[1]	5,733	11,250
Other paid-in capital	175	128
Retained earnings	3,510	1,960
Accumulated other comprehensive loss	(12)	(425)
Total common shareholders' equity	9,406	12,913
Total liabilities and shareholders' equity	$39,123	$49,269

(1) 1 billion shares authorized: 577 million shares and 698 million shares outstanding at December 31, 2007 and December 31, 2006, respectively.

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

Consolidated Statements of Common Shareholders' Equity and Comprehensive Income

	Common Stock		Other		Accumulated Other	
	Shares	Amount	Paid-In Capital	Retained Earnings	Comprehensive Income (Loss)	Total
(millions)						
Balance at December 31, 2004	680	$10,888	$ 92	$ 1,442	$ (996)	$11,426
Comprehensive income:						
Net income				1,033		1,033
Net deferred derivative losses—hedging activities, net of $1,648 tax					(2,846)	(2,846)
Unrealized gains on investment securities, net of $19 tax					27	27
Minimum pension liability adjustment, net of $3 tax					4	4
Foreign currency translation adjustments					10	10
Amounts reclassified to net income:						
Net realized gains on investment securities, net of $8 tax					(11)	(11)
Net derivative losses—hedging activities, net of $723 tax					1,250	1,250
Foreign currency translation adjustments					(2)	(2)
Total comprehensive income				1,033	(1,568)	(535)
Issuance of stock—employee and direct stock purchase plans	—	9				9
Stock awards and stock options exercised (net of change in unearned compensation)	12	363				363
Issuance of stock—forward equity transaction	10	319				319
Stock repurchase and retirement	(7)	(276)				(276)
Cash settlement—forward equity transaction	—	(17)				(17)
Tax benefit from stock awards and stock options exercised			31			31
Dividends and other adjustments			2	(925)		(923)
Balance at December 31, 2005	695	11,286	125	1,550	(2,564)	10,397
Comprehensive income:						
Net income				1,380		1,380
Net deferred derivative gains—hedging activities, net of $625 tax					1,173	1,173
Changes in unrealized gains on investment securities, net of $83 tax					126	126
Minimum pension liability adjustment, net of $7 tax					10	10
Foreign currency translation adjustments					(8)	(8)
Amounts reclassified to net income:						
Net realized gains on investment securities, net of $6 tax					(9)	(9)
Net derivative losses—hedging activities, net of $724 tax					1,182	1,182
Total comprehensive income				1,380	2,474	3,854
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—forward equity transaction	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)
Balance at December 31, 2006	698	11,250	128	1,960	(425)	12,913
Comprehensive income:						
Net income				2,539		2,539
Net deferred derivative losses—hedging activities, net of $140 tax					(223)	(223)
Changes in unrealized gains on investment securities, net of $75 tax					(110)	(110)
Changes in net unrecognized pension and other postretirement benefit costs, net of $80 tax					164	164
Amounts reclassified to net income:						
Net realized losses on investment securities, net of $4 tax					8	8
Net derivative losses—hedging activities, net of $376 tax					603	603
Net pension and other postretirement benefit costs, net of $10 tax					21	21
Recognition of foreign currency translation gains upon sale of foreign subsidiary					(50)	(50)
Total comprehensive income				2,539	413	2,952
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)
Balance at December 31, 2007	577	$ 5,733	$ 175	$ 3,510	$ (12)	$ 9,406

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

Consolidated Statements of Cash Flows

Year Ended December 31, (millions)	2007	2006	2005
Operating Activities			
Net income	$ 2,539	$ 1,380	$ 1,033
Adjustments to reconcile net income to net cash from operating activities:			
Gain on sale of non-Appalachian E&P business	(3,826)	—	—
Impairment of merchant generation assets	387	253	—
Charges associated with early retirement of debt	242	—	—
Extraordinary item, net of income taxes	158	—	—
Charges related to the termination of volumetric production payment agreements	139	—	—
Dominion Capital, Inc. impairment losses	88	89	35
Charges related to planned sale of gas distribution subsidiaries	—	188	—
Net realized and unrealized derivative (gains) losses	(245)	(242)	335
Depreciation, depletion and amortization	1,533	1,739	1,538
Deferred income taxes and investment tax credits, net	(1,285)	510	64
Gain on sale of emissions allowances held for consumption	(20)	(74)	(139)
Other adjustments	23	(31)	84
Changes in:			
Accounts receivable	294	684	(791)
Inventories	52	3	(220)
Deferred fuel and purchased gas costs, net	(349)	239	(57)
Accounts payable	(190)	(526)	686
Accrued interest, payroll and taxes	159	92	147
Deferred revenue	(71)	(262)	(323)
Margin deposit assets and liabilities	63	(7)	124
Other operating assets and liabilities	63	(30)	107
Net cash provided by (used in) operating activities	(246)	4,005	2,623
Investing Activities			
Plant construction and other property additions	(2,177)	(1,995)	(1,683)
Additions to gas and oil properties, including acquisitions	(1,795)	(2,057)	(1,675)
Proceeds from sales of gas and oil properties	12	393	595
Proceeds from sale of merchant generation facilities	339	—	—
Proceeds from sale of non-Appalachian E&P business	13,877	—	—
Acquisition of businesses	—	(91)	(877)
Proceeds from sales of securities and loan receivable collections and payoffs	1,285	1,110	754
Purchases of securities and loan receivable originations	(1,355)	(1,196)	(854)
Proceeds from sale of emissions allowances held for consumption	11	76	234
Proceeds from sale or disposal of other assets and investments	30	150	17
Other	(35)	116	129
Net cash provided by (used in) investing activities	10,192	(3,494)	(3,360)
Financing Activities			
Issuance (repayment) of short-term debt, net	(575)	713	1,045
Issuance of long-term debt	2,675	2,450	2,300
Repayment of long-term debt, including redemption premiums	(5,012)	(2,333)	(2,237)
Repayment of affiliated notes payable	(440)	(300)	—
Issuance of common stock	226	479	664
Repurchase of common stock	(5,768)	(540)	(276)
Common dividend payments	(931)	(970)	(923)
Other	24	(14)	(51)
Net cash provided by (used in) financing activities	(9,801)	(515)	522
Increase (decrease) in cash and cash equivalents	145	(4)	(215)
Cash and cash equivalents at beginning of year	142	146	361
Cash and cash equivalents at end of year[1]	$ 287	$ 142	$ 146
Supplemental Cash Flow Information:			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	$ 1,021	$ 920	$ 1,007
Income taxes	3,155	432	399
Significant noncash investing and financing activities:			
Accrued capital expenditures	58	258	220
Assumption of debt related to acquisitions of nonutility generating facilities	—	—	62
Dominion Capital, Inc. exchange of notes	—	—	258

(1) 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. On June 30, 2007, we merged our wholly-owned subsidiary, Consolidated Natural Gas Company (CNG), with our holding company, Dominion. As a result of the merger, all of CNG's subsidiaries became direct subsidiaries of Dominion.

We completed the sale of our non-Appalachian natural gas and oil exploration and production (E&P) operations during the third quarter of 2007. We chose to retain our Appalachian assets due to their strategic fit with our natural gas transmission and storage assets. These transactions are discussed in Note 6.

Following the sales of our non-Appalachian E&P operations, our principal subsidiaries are Virginia Electric and Power Company (Virginia Power), Dominion Energy, Inc. (DEI), Dominion Transmission, Inc. (DTI), Virginia Power Energy Marketing, Inc. (VPEM), Dominion Exploration and Production, Inc. (DEPI) and The East Ohio Gas Company (Dominion East Ohio).

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, 2007, Virginia Power served approximately 2.4 million retail customer accounts, including governmental agencies, as well as, wholesale customers such as rural electric cooperatives and municipalities. Virginia Power is a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), and its electric transmission facilities are integrated into the PJM wholesale electricity markets.

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

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

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

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

As of December 31, 2007, 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 Note 6. We also operate a liquefied natural gas (LNG) import and storage facility in Maryland. Our producer services operations involve the aggregation of natural gas supply and related wholesale activities. We also have nonregulated retail energy marketing operations that include the marketing of gas, electricity and related products and services to residential and small commercial customers. As of December 31, 2007, our retail energy marketing operations served approximately 1.6 million residential and commercial customer accounts in the Northeast, mid-Atlantic and Midwest regions of the U.S.

We have substantially exited the core operating businesses of Dominion Capital, Inc. (DCI) whose primary business was financial services, including loan administration, commercial lending and residential mortgage lending. Refer to Note 28 for information on a third-party collateralized debt obligation (CDO) entity that we consolidate.

Prior to a fourth quarter 2007 segment realignment, we managed our daily operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion E&P. During the fourth quarter of 2007, we realigned our business units to reflect our strategic refocusing and began managing our daily operations through three primary operating segments: Dominion Virginia Power (DVP), Dominion Generation and Dominion Energy. 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 6. 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 accounting principles generally accepted in the United States of America (GAAP). These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the periods presented. Actual results may differ from those estimates.

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

Certain amounts in the 2006 and 2005 Consolidated Financial Statements and footnotes have been recast to conform to the 2007 presentation.

Reapplication of SFAS No. 71

In March 1999, we discontinued the application of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (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 extraordinary item discussed here, the overall impact of these changes was not material to our results of operations or financial condition in 2007. These policy changes are discussed further in *Derivative Instruments*, *Investment Securities*, *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 accumulated other comprehensive income (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* (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* (SFAS No. 106), 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, 2007 and 2006 included $305 million and $267 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 from merchant generation facilities at market-based rates, sales of electricity to residential and commercial customers at contracted fixed prices and market-based rates, and electric trading revenue;
- **Regulated gas sales** consist primarily of state-regulated retail natural gas sales and related distribution services;
- **Nonregulated gas sales** consist primarily of sales of natural gas production at market-based rates and contracted fixed prices, sales of gas purchased from third parties, gas trading and marketing revenue, and sales activity related to agreements used to facilitate the marketing of gas production and gas transportation (buy/sell arrangements) described in Note 3. 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 volumetric production payment (VPP) transactions described in Note 13. 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 production and condensate, coal, emissions allowances held for resale and extracted products and sales activity related to agreements used to facilitate the marketing of oil production (buy/sell arrangements) described in Note 3;
- **Gas transportation and storage** consists primarily of regulated sales of gathering, transmission, distribution and storage services. Also included are regulated gas distribution charges to retail distribution service customers opting for alternate suppliers; and
- **Other revenue** consists primarily of miscellaneous service revenue from electric and gas distribution operations, gas and oil 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 locked in until July 1, 2007. Effective July 1, 2007, the fuel factor was adjusted as discussed under *Virginia Fuel Expenses* in Note 24. Approximately 83% of the cost of fuel used in electric generation and energy purchases used to serve utility customers is currently subject to deferral accounting.

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

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

If we conclude that it is more-likely-than-not that a tax position, or some portion thereof, will not be sustained, the related tax benefits are not recognized in the financial statements. For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. Unrecognized tax benefits 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 an income tax refund receivable, an increase in deferred tax liabilities, or a decrease in deferred tax assets. 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 refund 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 2007, 2006 and 2005, we recognized a $19 million reduction in interest expense and no penalties, $2 million of interest expense and no penalties and a $9

million reduction in interest expense and no penalties, respectively. At December 31, 2007 and 2006, respectively, we had accrued $9 million and $10 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

Effective January 1, 2006, 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.

Prior to January 1, 2006, we accounted for our stock-based compensation plans under the measurement and recognition provisions of Accounting

Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Under this method, stock option awards generally did not result in compensation expense, since their exercise price was typically equal to the market price of our common stock on the date of grant. Accordingly, stock-based compensation expense was included as a pro forma disclosure in the footnotes to our financial statements.

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

Year Ended December 31,	2005
(millions, except per share amounts)	
Net income—as reported	$1,033
Add: actual stock-based compensation expense, net of tax[1]	15
Deduct: pro forma stock-based compensation expense, net of tax	(16)
Net income—pro forma	$1,032
Basic EPS—as reported	$ 1.51
Basic EPS—pro forma	1.51
Diluted EPS—as reported	1.50
Diluted EPS—pro forma	1.50

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

Prior to the adoption of SFAS No. 123R, we presented the benefits of tax deductions resulting from the exercise of stock-based compensation as an operating cash flow in our Consolidated Statements of Cash Flows. 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 FASB Staff Position No. FAS 123(R)-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, 2007 and 2006, we realized $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 a financing cash flow.

Restricted stock awards granted prior to January 1, 2006 contain terms that accelerate vesting upon retirement. Our previous practice was to recognize compensation cost for these awards over the stated vesting term unless vesting was actually accelerated by retirement. Following our adoption of SFAS No. 123R, we continue to recognize compensation cost over the stated vesting term for existing restricted stock awards, but we are now required to recognize compensation cost over the shorter of: (1) the stated vesting term or (2) the period from the date of grant to the date of retirement eligibility for newly issued or modified restricted stock awards with similar terms. In the years ended December 31, 2007 and 2006, we recognized approximately $3 million and $5 million, respectively, of compensation cost related to awards previously granted to retirement eligible employees. At December 31, 2007, unrecognized compensation cost for these restricted stock awards held by retirement eligible employees totaled approximately $1 million.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. At December 31, 2007 and 2006, accounts payable included $93 million and $125 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

Inventory is carried at the lower of cost or market (LOCOM). 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, 2007 and 2006. Based on the average price of gas purchased during 2007, the cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by approximately $152 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.

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

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

Statement of Income Presentation:

- **Derivatives Held for Trading Purposes:** All changes in fair value, including amounts realized upon settlement, are presented in revenue on a net basis as nonregulated electric sales, nonregulated gas sales or other energy-related commodity sales.

- **Financially-Settled Derivatives—Not Held for Trading Purposes and Not Designated as Hedging Instruments:** All unrealized changes in fair value and settlements are presented in other operations and maintenance expense on a net basis.

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

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

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 these 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.

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 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, until earnings are affected by the hedged item. 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 these derivative instruments result in the recognition of regulatory assets or regulatory liabilities. Realized gains or losses on the derivative instruments subject to regulatory accounting are generally recognized when the related transactions impact earnings. For cash flow hedge transactions, we discontinue hedge accounting if the occurrence of the forecasted transaction is determined to be no longer probable. We reclassify any derivative gains or losses reported in AOCI to earnings when the forecasted item is included in earnings, if it should occur, or earlier, if it becomes probable that the forecasted transaction will not occur.

Fair Value Hedges—We also use fair value hedges to mitigate the fixed price exposure inherent in certain firm commodity commitments and natural gas inventory. In addition, we have designated interest rate swaps as fair value hedges 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. 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 these derivative instruments result in the recognition of regulatory assets or regulatory liabilities. Realized gains or losses on the derivative instruments subject to regulatory accounting are generally recognized when the related transactions impact earnings. For fair value hedge transactions, we discontinue hedge accounting if the hedged item no longer qualifies for hedge accounting. 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.

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

Valuation Methods

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

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

Investment Securities

We account for and classify investments in marketable equity and debt securities into two categories. Debt and equity securities held in rabbi trusts associated with certain deferred compensation plans are classified as trading securities. Trading securities are reported at fair value with net realized and unrealized gains and losses included in earnings. All other debt and equity securities are classified as available-for-sale securities, which are also reported at fair value. Upon reapplication of SFAS No. 71 in April 2007 for our utility generation operations, net realized and unrealized gains and losses on our utility nuclear decommissioning trusts are recorded to a regulatory liability for certain jurisdictions. For our merchant generation nuclear decommissioning trusts, net realized gains and losses and any other-than-temporary declines in fair value are included in other income and unrealized gains are reported as a component of AOCI, net of tax. We continue to report all other available-for-sale securities at fair value with realized gains and losses and any other-than-temporary declines in fair value included in other income and unrealized gains and losses reported as a component of AOCI, net of tax.

We analyze all securities classified as available-for-sale to determine whether a decline in fair value should be considered other than temporary. 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. In addition, retained interests from securitizations of financial assets are first evaluated in accordance with Emerging Issues Task Force (EITF) Issue No. 99-20, *Recognition of Interest Income and Impairments of Purchased and Retained Beneficial Interests in Securitized Financial Assets*. 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 regulatory authorities limit our ability to oversee the day-to-day management of our nuclear decommissioning trust fund investments, we do not have the ability to hold individual securities in the trusts. Accordingly, we consider all securities held by our nuclear decommissioning trusts with market values below their cost bases to be other-than-temporarily impaired.

Property, Plant and Equipment

Property, plant and equipment, including additions and replacements is recorded at original cost, 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, an allowance for funds used during construction (AFUDC). The cost of repairs and maintenance, including minor additions and replacements, is charged to expense as it is incurred. In 2007, 2006 and 2005, we capitalized interest costs and AFUDC of $103 million, $134 million and $103 million, 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 State Corporation Commission (Virginia Commission) previously allowed for current recovery of construction financing costs.

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. Cost of removal collections from utility customers and expenditures not representing asset retirement obligations (AROs) are recorded as regulatory liabilities or regulatory assets.

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,	2007	2006	2005
(percent)			
Generation (1)	2.24	2.07	2.04
Transmission	2.26	2.28	2.25
Distribution	3.21	3.28	3.19
Storage	2.78	3.10	3.15
Gas gathering and processing	2.09	2.05	2.21
General and other	4.92	5.22	5.80

(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 is expected to increase 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 Securities and Exchange Commission (SEC). Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized. These capitalized costs are subject to a quarterly ceiling test. Under the ceiling test, amounts capitalized are limited to the present value of estimated future net revenues to be derived from the anticipated production of proved gas and oil reserves, discounted at 10 percent, 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 6% 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, 2007. 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.

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 6 to our Consolidated Financial Statements.

Emissions Allowances

Emissions allowances are issued by the Environmental Protection Agency (EPA) and permit the holder of the allowance to emit certain gaseous by-products of fossil fuel combustion, including sulfur dioxide (SO_2) and nitrogen oxide (NO_x). Allowances may be transacted with third parties or consumed as these emissions are generated. Allowances allocated to or acquired by our generation operations are held primarily for consumption. 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 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, after a portion of goodwill has been allocated to a business to be disposed of 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 on April 4, 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 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

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.

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

SFAS 155

Effective January 1, 2007, we adopted SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments* (SFAS No. 155), which permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that would otherwise require bifurcation. Our adoption of SFAS No. 155 had no impact on our results of operations or financial condition.

2006

SFAS 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). 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. The following table illustrates the incremental effect of adopting the provisions of SFAS No. 158 on our Consolidated Balance Sheet at December 31, 2006:

	Prior to adopting SFAS No. 158	Effect of Adopting SFAS No. 158	As Reported at December 31, 2006
(millions)			
Assets:			
Pension and other postretirement benefit assets	$ 1,858	$ (612)	$ 1,246
Regulatory assets	404	135	539
Liabilities:			
Other current liabilities	743	2	745
Deferred income taxes and investment tax credits	6,097	(239)	5,858
Regulatory liabilities	601	13	614
Other deferred credits and other liabilities	891	82	973
Shareholders' Equity:			
AOCI	(90)	(335)	(425)

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. The adjustments to AOCI, regulatory assets and regulatory liabilities at adoption of SFAS No. 158 represent net actuarial gains (losses), prior service cost (credit) and transition obligation remaining from our initial adoption of SFAS No. 106, all of which were previously not recognized in our Consolidated Balance Sheet. The amounts in AOCI, regulatory assets and regulatory liabilities will be subsequently recognized as a component of future net periodic benefit cost. Further, actuarial gains and losses that arise in subsequent periods and are not recognized as net periodic benefit cost (credit) in the same periods will be recognized as a component of other comprehensive income (loss) or regulatory assets or regulatory liabilities as appropriate. Those amounts will be subsequently recognized as a component of net periodic benefit cost (credit) on the same basis as the amounts recognized in AOCI, regulatory assets and regulatory liabilities at adoption of SFAS No. 158.

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* (EITF 04-13), 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. Pursuant to the transition provisions of EITF 04-13, activity related to buy/sell arrangements that were entered into prior to April 1, 2006 and have not been modified or renewed after that date continue to be reported on a gross basis and are included in the activity summarized below:

Year Ended December 31,	2007	2006	2005
(millions)			
Sale activity included in operating revenue	$ 67	$576	$623
Purchase activity included in operating expenses(1)	72	578	651

(1) Included in other energy-related commodity purchases expense and purchased gas expense in our Consolidated Statements of Income.

2005

FIN 47

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

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

Year Ended December 31,	2005
(millions, except per share amounts)	
Net income—as reported	$1,033
Net income—pro forma	1,038
Basic EPS—as reported	1.51
Basic EPS—pro forma	1.52
Diluted EPS—as reported	1.50
Diluted EPS—pro forma	1.51

If we had applied the provisions of FIN 47 as of January 1, 2005, our AROs would have increased by $140 million.

Note 4. Recently Issued Accounting Standards

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157), which defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability and establishes a fair value hierarchy of three levels that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data. SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy. The provisions of SFAS No. 157 became effective for us beginning January 1, 2008. Generally, the provisions of this statement are to be applied prospectively. Certain situations, however, require retrospective application as of the beginning of the year of adoption through the recognition of a cumulative effect of accounting change. Such retrospective application is required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses under EITF Issue 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. Retrospective application will result in an immaterial amount recognized through cumulative effect of accounting change. We are currently evaluating the impact that SFAS No. 157 will have on our results of operations and financial condition for the provisions to be applied prospectively.

In February 2008, the FASB issued FSP FAS No. 157-1, *Application of FASB Statement No. 157 to FASB Statement No. 13 and Its Related Interpretive Accounting Pronouncements That Address Leasing Transactions*, 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 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).

In January 2008, the FASB proposed FSP FAS No. 157-c, *Measuring Liabilities Under FASB Statement No. 157,* which if issued would clarify the principles in SFAS No. 157 for the fair value measurements of liabilities. Specifically, this FSP would require an entity to measure liabilities first based on a quoted price in an active market for an identical liability, however in the absence of such information, an entity would be allowed to measure the fair value of the liability at the amount it would receive as proceeds if it were to issue that liability at the measurement date.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159). SFAS No. 159 provides an entity with the option, at specified election dates, to measure certain financial assets and liabilities and other items at fair value, with changes in fair value recognized in earnings as those changes occur. SFAS No. 159 also establishes presentation and disclosure requirements that include displaying the fair value of those assets and liabilities for which the entity elected the fair value option on the face of the balance sheet and providing management's reasons for electing the fair value option for each eligible item. The provisions of SFAS No. 159 became effective for us beginning January 1, 2008. We are currently evaluating whether fair value accounting is appropriate for any of our eligible items and cannot estimate the impact that SFAS No. 159 may have on our results of operations and financial condition.

SFAS No. 141R

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS No. 141R). 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 the information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS No. 141R requires that acquisition-related costs be expensed as incurred. SFAS No. 141R amends SFAS No. 109 to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. The provisions of SFAS No. 141R will become effective for acquisitions on or after January 1, 2009, except for the tax provisions which apply to business combinations regardless of the acquisition date.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements* (SFAS No. 160). SFAS No. 160 requires that noncontrolling (minority) interests be reported as a component of equity, net income attributable to the parent and to the non-controlling 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 will become effective for us beginning January 1, 2009. We are currently evaluating the impact that SFAS No. 160 will have on our results of operations and financial condition.

EITF 06-4

In September 2006, the FASB ratified the consensus reached by the EITF on Issue No. 06-4, *Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements* (EITF 06-4). EITF 06-4 specifies that if an employer provides a benefit to an employee under an endorsement split-dollar life insurance arrangement that extends to postretirement periods, it should recognize a liability for future benefits in accordance with SFAS No. 106 (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 provisions of EITF 06-4 became effective for us beginning January 1, 2008 and will not have a material impact on our results of operations or financial condition.

EITF 06-11

In June 2007, the FASB ratified the consensus reached by the EITF on Issue No. 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards* (EITF 06-11). EITF 06-11 addresses the recognition of income tax benefits realized from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for nonvested equity-classified share-based payment awards. Effective January 1, 2008, we began recognizing such income tax benefits as an increase to additional paid-in capital rather than as a reduction to income tax expense. We do not expect EITF 06-11 to have a material impact on our results of operations or financial condition.

FSP FIN 39-1

In April 2007, the FASB issued FSP No. FIN 39-1, *Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts* (FSP FIN 39-1). FSP FIN 39-1 amends FIN 39 to permit the offsetting of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement that have been offset. FSP FIN 39-1 became effective for us beginning January 1, 2008 and must be applied retroactively to all financial statements presented, unless it is impracticable to do so. We are currently evaluating the impact that FSP FIN 39-1 may have on our financial condition. We do not expect FSP FIN 39-1 to have an impact on our results of operations or cash flows.

NOTE 5. ACQUISITIONS

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. Following the disposition of these, and all of our other non-Appalachian E&P operations during 2007 and the realignment of our business units in the fourth quarter of 2007, the historical results of these operations are now included in our Corporate and Other segment.

Kewaunee Nuclear Power Station

In July 2005, we completed the acquisition of the 556 megawatt (Mw) Kewaunee nuclear power station (Kewaunee), located in northeastern Wisconsin, from Wisconsin Public 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.

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 plants, collectively referred to as Dominion New England, include the 1,568 Mw Brayton Point power station in Somerset, Massachusetts; the 754 Mw Salem Harbor power station in Salem, Massachusetts; and the 432 Mw Manchester Street power station in Providence, Rhode Island. The operations of Dominion New England are included in our Dominion Generation operating segment.

NOTE 6. DISPOSITIONS

Sale of Non-Appalachian Natural Gas and Oil E&P Operations and Assets

We have completed the sale of our non-Appalachian natural gas and oil E&P operations and assets for approximately $13.9 billion. At December 31, 2006, our non-Appalachian natural gas and oil assets included about 5.5 trillion cubic feet equivalent (Tcfe) of proved reserves. The Appalachian assets that we have retained included about 1.1 Tcfe of proved reserves at December 31, 2007 and 2006.

Due to the sale of our entire Canadian cost pool, the results of operations for our Canadian E&P business are reported as discontinued operations in our Consolidated Statements of Income. The results of operations for our U.S. non-Appalachian E&P business 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 19 and 21.

The E&P operations we have sold are as follows:

Canadian Operations

On June 26, 2007, we completed the sale of our Canadian E&P operations to Paramount Energy Trust and Baytex Energy Trust for approximately $624 million. The sale resulted in an after-tax gain of $59 million ($0.08 per share). We expect to pay the tax related to the gain on the sale by the end of the second quarter of 2008.

The following table presents selected information regarding the results of operations of our Canadian E&P operations, which are reported as discontinued operations in our Consolidated Statements of Income:

Year Ended December 31,	2007	2006	2005
(millions)			
Operating revenue	$ 82	$144	$134
Income before income taxes	145(1)	24	29

(1) Amount includes pre-tax gain of $191 million recognized on the sale.

U.S. Operations

On July 2, 2007, we completed the sale of substantially all of our offshore E&P operations to Eni Petroleum Co. Inc. (Eni) for approximately $4.73 billion.

On July 31, 2007, we completed the sale to HighMount Exploration & Production LLC, a newly formed subsidiary of Loews Corporation, of our E&P operations in the Alabama, Michigan and Permian basins for approximately $4.0 billion.

Also on July 31, 2007, we completed the sale to XTO Energy Inc. of our E&P operations in the Gulf Coast, Rocky Mountains, South Louisiana and San Juan Basin of New Mexico for approximately $2.5 billion.

On August 31, 2007, we completed the sale to Linn Energy, LLC, of our E&P operations in the Mid-Continent Basin for approximately $2.0 billion.

Costs Associated with Disposal of Non-Appalachian E&P Operations

The sales of our U.S. non-Appalachian E&P operations resulted in the discontinuance of hedge accounting for certain cash flow hedges since it became probable that the forecasted sales of gas and oil will not occur. In connection with the discontinuance of hedge accounting for these contracts, we recognized charges, recorded in other operations and maintenance expense in our Consolidated Statement of Income, predominantly reflecting the reclassification of losses from AOCI to earnings and subsequent changes in fair value of these contracts of $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 of approximately $171 million ($108 million after-tax) for the recognition of certain forward gas contracts that previously qualified for the normal purchase and sales exemption under SFAS No. 133. The $171 million charge includes $139 million associated with 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. We paid federal income taxes related to the gain on the sale in the fourth quarter of 2007. We expect to pay the related state income taxes by the end of the second quarter of 2008.

The total impact on net income from the sale of our Canadian and U.S. non-Appalachian E&P operations was 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 19.

Disposition of Partially Completed Generation Facility

In September 2007, we completed the sale of the Dresden Energy merchant generation facility (Dresden) to AEP Generating Company (AEP) for $85 million. During 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 LLC (Gichner), all of the issued and outstanding shares of the capital stock of Gichner, Inc. (an affiliate of Gichner), as well as all of the membership interests in Dallastown Realty (Dallastown).

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	2005
(millions)			
Operating revenue	$ 29	$ 41	$ 28
Income (loss) before income taxes	(7)	2	1

Sale of Merchant Generation Facilities

In 2007, we sold three of our natural gas-fired merchant generation peaking facilities (Peaker facilities) for net cash proceeds of $254 million. The sale resulted in a $24 million after-tax loss ($0.03 per share). The Peaker facilities are:

- Armstrong, a 625 Mw station in Shelocta, Pennsylvania;
- Troy, a 600 Mw station in Luckey, Ohio; and
- Pleasants, a 313 Mw station in St. Mary's, West Virginia.

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 carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheet at

December 31, 2006 were comprised of property, plant and equipment, net ($245 million), inventory ($13 million) and accounts payable ($3 million).

The following table presents selected information regarding the results of operations of the Peaker facilities, which are reported as discontinued operations in our Consolidated Statements of Income:

Year Ended December 31,	2007	2006	2005
(millions)			
Operating revenue	$ 5	$ 42	$ 71
Loss before income taxes	(31)	(283)	(19)

The Peaker facilities' operating revenues were related to sales to other Dominion affiliates. In addition, the Peaker facilities purchased $1 million, $14 million and $38 million of electric fuel from affiliates in 2007, 2006 and 2005.

Planned Sale of Regulated Gas Distribution Subsidiaries

On March 1, 2006, we entered into an agreement with Equitable Resources, Inc. (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. 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 are seeking other offers for the purchase of these utilities.

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,	2007	2006
(millions)		
ASSETS		
Current Assets		
Customer receivables	$ 147	$ 144
Other	109	125
Total current assets	256	269
Property, Plant and Equipment		
Property, plant and equipment	1,160	1,129
Accumulated depreciation, depletion and amortization	(367)	(375)
Total property, plant and equipment, net	793	754
Deferred Charges and Other Assets		
Regulatory assets	109	106
Other	2	4
Total deferred charges and other assets	111	110
Assets held for sale	$1,160	$1,133
LIABILITIES		
Current Liabilities	$ 210	$ 236
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	208	187
Other	74	71
Total deferred credits and other liabilities	282	258
Liabilities held for sale	$ 492	$ 494

EITF Issue No. 03-13, *Applying the Conditions of Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations* (EITF 03-13), 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,	2007	2006	2005
(millions)			
Operating revenue	$673	$ 699	$742
Income (loss) before income taxes	78	(112)	54

During 2006, we recognized a $166 million ($104 million after-tax) charge, recorded in other operations and maintenance expense in our Consolidated Statement of Income, resulting from the write-off of certain regulatory assets related to the planned sale of Peoples and Hope, since the recovery of those assets was no longer probable. During 2006, we also established $145 million of deferred tax liabilities, as discussed in Note 9.

Note 7. Pro Forma Financial Statements (Unaudited)

The accompanying unaudited Pro Forma Condensed Consolidated Statements of Income for the year ended December 31, 2007, reflect the sale of our non-Appalachian E&P operations as if it had occurred on January 1, 2007.

The pro forma adjustments have been based on the operations of our non-Appalachian E&P business during the period presented, the impact of the sale of these operations and other transactions resulting from the sale.

The pro forma adjustments have been made to illustrate the anticipated financial impact of the sale upon Dominion and are based upon available information and assumptions that we believe to be reasonable at the date of this filing. Consequently, the pro forma financial information presented is not necessarily indicative of the consolidated results of operations that would have been reported had the transaction actually occurred on the date presented. Moreover, the pro forma financial information does not purport to indicate the future results that Dominion will experience.

Pro Forma Condensed Consolidated Statement of Income
Year Ended December 31, 2007

(millions, except per share amounts)	As Reported	Less: E&P Dispositions	Pro Forma Adjustments	Pro Forma Results
Operating Revenue	$ 15,674	$ 1,318	$ —	$ 14,356
Operating Expenses				
Electric fuel and energy purchases	3,511	—	—	3,511
Purchased electric capacity	439	—	—	439
Purchased gas	2,766	68	—	2,698
Other energy-related commodity purchases	252	—	—	252
Other operations and maintenance	4,854	1,097	(8)(1)	3,749
Gain on sale of U.S. non-Appalachian E&P business	(3,635)	(3,635)	—	—
Depreciation, depletion and amortization	1,368	431	—	937
Other taxes	552	82	—	470
Total operating expenses	10,107	(1,957)	(8)	12,056
Income from operations	5,567	3,275	8	2,300
Other income	102	1	—	101
Interest and related charges	1,175	—	(234)(1) (153)(2)	788
Income from continuing operations before income tax expense and minority interest	4,494	3,276	395	1,613
Income tax expense	1,783	1,446	153(3)	490
Minority interest	6	—	—	6
Income from continuing operations	$ 2,705	$ 1,830	$ 242	$ 1,117
Earnings Per Share				
Income from continuing operations—Basic	$ 4.15	—	—	$ 1.93
Income from continuing operations—Diluted	$ 4.13	—	—	$ 1.91
Weighted average shares outstanding—Basic	650.8	—	(71.5)(4)	579.3
Weighted average shares outstanding—Diluted	655.2	—	(71.5)(4)	583.7

(1)Represents the removal of non-recurring expenses associated with the completion of our debt tender offer in July 2007, using a portion of the proceeds from the disposition of our non-Appalachian E&P operations.

(2)Represents the prorated decrease in interest expense resulting from the repayment of $3.4 billion in debt with a portion of the proceeds from the disposition of our non-Appalachian E&P operations. This amount is comprised of $2.5 billion in long term debt retired in connection with our debt tender offer completed in July 2007; $500 million of bank debt incurred at our CNG subsidiary which was repaid prior to the merger of that subsidiary with and into Dominion, effective June 30, 2007; $200 million of senior notes originally issued by our subsidiary Dominion Oklahoma Texas Exploration & Production, Inc., which were redeemed in June 2007 and $200 million of trust preferred securities originally issued by Dominion CNG Capital Trust I, which were redeemed in July 2007.

(3)Reflects the income tax effects of the pro forma adjustments associated with the disposition of our non-Appalachian E&P operations based on the weighted-average statutory rates for all jurisdictions that would have applied during the period.

(4)Reflects the prorated impact of our equity tender offer discussed in Note 21. We purchased approximately 115.5 million shares at a price of $45.50 per share, with a portion of the proceeds received from the disposition.

Nonrecurring Items Related to the Dispositions
Certain nonrecurring items resulting from the disposition of our non-Appalachian E&P operations have not been reflected in the accompanying Condensed Pro Forma Consolidated Statements of Income. See *Costs Associated with Disposal of Non-Appalachian E&P Operations* in Note 6.

NOTE 8. OPERATING REVENUE

Our operating revenue consists of the following:

Year Ended December 31,	2007	2006	2005
(millions)			
Electric sales:			
Regulated	$ 6,044	$ 5,451	$ 5,543
Nonregulated	3,099	2,528	3,044
Gas sales:			
Regulated	1,174	1,397	1,763
Nonregulated	3,238	3,524	4,182
Other energy-related commodity sales	846	1,939	2,005
Gas transportation and storage	1,031	943	899
Other	242	515	373
Total operating revenue	$15,674	$16,297	$17,809

NOTE 9. INCOME TAXES

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

Year Ended December 31,	2007	2006	2005
(millions)			
Current:			
Federal	$2,875	$195	$420
State	217	139	103
Total current	3,092	334	523
Deferred:			
Federal	(1,283)	536	86
State	(15)	73	(19)
Total deferred	(1,298)	609	67
Amortization of deferred investment tax credits	(11)	(16)	(17)
Total income tax expense	$1,783	$927	$573

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

Year Ended December 31,	2007	2006	2005
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	(0.2)	5.9	—
State taxes, net of federal benefit	3.1	5.8	3.6
Valuation allowances	(2.8)	(6.6)	1.0
Domestic production activities deduction	(0.5)	(0.1)	—
Amortization of investment tax credits	(0.2)	(0.5)	(0.8)
Employee stock ownership plan deduction	(0.3)	(0.6)	(0.8)
Employee pension and other benefits	(0.2)	(0.3)	(1.2)
Other, net	0.2	(1.1)	(1.1)
Effective tax rate	39.7%	37.6%	35.7%

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 will now be 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 28. This net benefit was partially offset by the establishment of $145 million of 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, *Recognition of Deferred Tax Assets for a Parent Company's Excess Tax Basis in the Stock of a Subsidiary that is Accounted for as a Discontinued Operation* (EITF 93-17). Although these subsidiaries are not classified as discontinued operations, EITF 93-17 requires that the deferred tax impact of the excess of the financial reporting basis over the tax basis of a parent's investment in a subsidiary be recognized when it is apparent that this difference will reverse in the foreseeable future. We recorded these deferred tax liabilities, since the financial reporting basis of our investment in Peoples and Hope exceeded our tax basis. This difference and the related deferred taxes were expected to reverse and partially offset current tax expense recognized upon closing of the sale.

In January 2008, Dominion and Equitable agreed to terminate the agreement for the sale of Peoples and Hope. We anticipate that the ultimate disposal of these subsidiaries will be structured as a sale of the subsidiaries' stock; however, we now expect that the taxable gain will be determined based on the sale of the subsidiaries' underlying assets. Accordingly, in January 2008, we reversed $136 million of deferred tax liabilities, representing the adjusted balance of the amounts established under EITF 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,	2007	2006
(millions)		
Deferred income taxes:		
Total deferred income tax assets	$1,871	$1,406
Total deferred income tax liabilities	6,173	6,918
Total net deferred income tax liabilities	$4,302	$5,512
Total deferred income taxes:		
Depreciation method and plant basis differences	$2,724	$2,878
Gas and oil E&P related differences	520	2,186
Deferred state income taxes	506	514
Pension benefits	582	431
Recognition of deferred taxes—stock of subsidiaries held for sale	136	145
Loss and credit carryforwards	(157)	(762)
Valuation allowances	23	144
Other	(32)	(24)
Total net deferred income tax liabilities	$4,302	$5,512

At December 31, 2007, we had the following loss and credit carryforwards:

- Federal loss carryforwards of $49 million that expire if unutilized during the period 2009 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 $1,245 million that expire if unutilized during the period 2008 through 2027. A valuation allowance on $696 million of these carryforwards has been established; and
- State minimum tax credits of $81 million that do not expire and other state income tax credits of $21 million that will expire if unutilized during the period 2011 through 2017.

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. At December 31, 2006, our Consolidated Balance Sheet included $187 million of income tax-related contingent liabilities, including $135 million related to our deduction of a calendar year 2003 net operating loss, a substantial portion of which resulted from a write-off related to our discontinued telecommunications business and $27 million related to our use of certain tax credits to reduce tax payments.

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. As a result, we reversed the tax-related contingent liabilities, described above, and included such reversals with the amounts resulting from our evaluation of tax positions for recognition and measurement under FIN 48 in the charge to beginning retained earnings at January 1, 2007, representing the cumulative effect of the change in accounting principle.

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 impact the financial statements by increasing taxes payable, reducing tax refund receivables, increasing deferred tax liabilities or decreasing deferred tax assets. 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 refund receivable) is accompanied by a decrease in deferred tax liabilities.

A reconciliation of changes in our unrecognized tax benefits during 2007 follows:

	Amount
(millions)	
Balance at January 1, 2007	$ 625
Increases—prior period positions	64
Decreases—prior period positions	(40)
Current period positions	70
Prior period positions becoming otherwise deductible in current period	(252)
Settlements with tax authorities	(60)
Balance at December 31, 2007	$ 407

Unrecognized tax benefits, that, if recognized, would affect the effective tax rate, increased from $76 million at January 1, 2007 to $101 million at December 31, 2007. Due to this increase (excluding the effects of a $1 million increase in unrecognized tax benefits related to refund claims and $1 million paid to tax authorities for settlements), total income tax expense for 2007 increased by $25 million.

For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. 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 6), these prior year amounts, if ultimately determined to be capital losses, would be deductible in 2007. When uncertainty about the deductibility of amounts is limited to the timing of such deductibility, any tax liabilities recognized for prior periods would be subject to offset with the availability of refundable amounts from later periods when such deductions could otherwise be taken. Pending resolution of these timing uncertainties, interest is being accrued 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. Other parties are currently engaged in litigation to determine whether United Kingdom Windfall Profits taxes qualify for the U.S. federal foreign tax credit. Depending on the progress of those proceedings, we may file a refund claim for these credits in 2008. At this time, we cannot estimate the amount of

the change, if any, that could possibly result to our unrecognized tax benefits.

For CNG and its former subsidiaries, tax years prior to Dominion's acquisition of CNG in January 2000 are no longer subject to examination, except with respect to amended returns filed in June 2007 for tax years 1996, 1997 and 1998, claiming refunds for certain tax credits.

In 2007, the U.S. Congressional Joint Committee on Taxation completed its review of our settlement with the Appellate Division of the Internal Revenue Service (IRS Appeals) for tax years 1993 through 1997. In October of 2007, we received a tax refund of $34 million for those years. Due to carryback adjustments, we will not receive the refund for 1998 until issues for later tax years, pending at IRS Appeals, are settled.

We are currently engaged in settlement negotiations with IRS Appeals regarding certain adjustments proposed during the examination of tax years 1999 through 2001. We have reached tentative settlement on substantially all of the issues, except we are reserving the right to pursue refunds related to certain deductions. Negotiations are expected to conclude in 2008 without any impact to our results of operations.

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. 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 1999 through 2001, we believe that it is reasonably possible, based on settlement negotiations and risks of litigation, that unrecognized tax benefits could decrease by up to $47 million over the next twelve months. In addition, unrecognized tax benefits could be reduced by $18 million to recognize prior period amounts becoming otherwise deductible in the current period. With regard to tax years 2002 through 2005, we cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur during the next twelve months.

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

State	Earliest Open Tax Year
Pennsylvania	2000
Connecticut	2001
Massachusetts	2005
Virginia	2004
West Virginia	2004

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 2008, the President of the U.S. signed into law the Economic Stimulus Act of 2008 (the Act). The Act includes provisions to stimulate economic growth, including incentives for increased capital investment by businesses. We are currently evaluating the Act but have not yet determined its impact on our 2008 and future results of operations, cash flows or financial condition.

NOTE 10. 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,	2007	2006	2005
(millions)			
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:			
Fair value hedges	$ 6	$ (22)	$ 18
Cash flow hedges(1)	50	44	(79)
Net ineffectiveness	$ 56	$ 22	$ (61)

(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 2007, 2006 and 2005, amounts excluded from the measurement of effectiveness did not have a significant impact on net income.

See Note 6 for a discussion of the discontinuance of hedge accounting for 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 our 515 Mw State Line power station (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 other operations and maintenance expense 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 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.

As a result of a delay in reaching anticipated production levels in the Gulf of Mexico, we discontinued hedge accounting for certain cash flow hedges in March 2005, since it became probable that the forecasted sales of oil would not occur. The discontinuance of hedge accounting for these contracts resulted in the reclassification of $30 million ($19 million after-tax) of losses from AOCI to earnings in March 2005.

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

The following table presents selected information, for jurisdictions not subject to cost-of-service rate regulation, related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at December 31, 2007:

	AOCI After Tax	Portion Expected to be Reclassified to Earnings during the Next	Maximum Term

(millions)				12 Months After Tax	
Commodities:					
Gas	$	15	$	5	39 months
Electricity		(12)		14	48 months
Other		(17)		(13)	36 months
Interest rate		(31)		(4)	222 months
Foreign currency		3		2	41 months
Total	$	(42)	$	4	

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 11. EARNINGS PER SHARE

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

Year Ended December 31,	2007	2006	2005
(millions, except per share amounts)			
Income from continuing operations before extraordinary item and cumulative effect of change in accounting principle	$2,705	$1,530	$1,033
Income (loss) from discontinued operations, net of tax	(8)	(150)	6
Extraordinary item, net of tax	(158)	—	—
Cumulative effect of change in accounting principle, net of tax	—	—	(6)
Net income	$2,539	$1,380	$1,033
Basic EPS			
Average shares of common stock outstanding—basic	650.8	699.5	684.6
Income from continuing operations before extraordinary item and cumulative effect of change in accounting principle	$ 4.15	$ 2.19	$ 1.51
Income (loss) from discontinued operations	(0.01)	(0.22)	0.01
Extraordinary item	(0.24)	—	—
Cumulative effect of change in accounting principle	—	—	(0.01)
Net income	$ 3.90	$ 1.97	$ 1.51
Diluted EPS			
Average shares of common stock outstanding	650.8	699.5	684.6
Net effect of potentially dilutive securities(1)	4.4	3.7	4.3
Average shares of common stock outstanding—diluted	655.2	703.2	688.9
Income from continuing operations before extraordinary item and cumulative effect of change in accounting principle	$ 4.13	$ 2.17	$ 1.50
Income (loss) from discontinued operations	(0.01)	(0.21)	0.01
Extraordinary item	(0.24)	—	—
Cumulative effect of change in accounting principle	—	—	(0.01)
Net income	$ 3.88	$ 1.96	$ 1.50

(1)Potentially dilutive securities consist of options, restricted stock and contingently convertible senior notes. 2006 potentially dilutive securities also included equity-linked securities and 2005 potentially dilutive securities also included shares that were issuable under a forward equity sale agreement.

Potentially dilutive securities with the right to purchase approximately 2 million and 6 million average common shares for the years ended December 31, 2006 and 2005, respectively, were not included in the respective period's calculation of diluted EPS because the exercise or purchase prices included in those instruments were greater than the average market price of the common shares. There were no such anti-dilutive securities outstanding for the year-ended December 31, 2007.

NOTE 12. INVESTMENT SECURITIES

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

Available-for-sale securities as of December 31, 2007 and 2006 are summarized below. There were no unrealized losses included in AOCI as of December 31, 2007 or 2006.

	Fair Value	Total Unrealized Gains
(millions)		
2007		
Equity securities	$1,784	$ 486
Debt securities	1,047	33
Total	$2,831	$ 519(1)
2006		
Equity securities	$1,753	$ 456
Debt securities	1,003	15
Total	$2,756	$ 471(2)

(1)Included in AOCI and regulatory liabilities as discussed in Note 2.

(2)*Included in AOCI in our Consolidated Balance Sheet.*

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 owns six residual trusts with no book basis at December 31, 2007.

The fair value of all other debt securities at December 31, 2007, by contractual maturity are as follows:

	Amount
(millions)	
Due in one year or less	$ 77
Due after one year through five years	291
Due after five years through ten years	296
Due after ten years	383
Total	$ 1,047

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

Year Ended December 31,	2007	2006	2005
(millions)			
Available-for-sale securities:			
Proceeds from sales	$916	$1,025	$754
Realized gains(1)	100	90	46
Realized losses(1)	144	77	49
Trading securities:			
Net unrealized gain (loss)	(3)	9	6

(1)*Includes realized gains and losses recorded to a regulatory liability in 2007, as discussed in Note 2.*

NOTE 13. PROPERTY, PLANT AND EQUIPMENT

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

At December 31,	2007	2006
(millions)		
Utility:		
Generation	$10,237	$10,088
Transmission	3,817	3,627
Distribution	8,332	7,944
Storage	1,146	1,109
Nuclear fuel	930	907
Gas gathering and processing	647	433
General and other	732	735
Other—including plant under construction	1,819	1,136
Total utility	27,660	25,979
Nonutility:		
Exploration and production properties being amortized:		
Proved	1,789	11,747
Unproved	—	913
Unproved exploration and production properties not being amortized	10	1,067
Merchant generation—nuclear	1,077	1,034
Merchant generation—other	1,393	1,311
Nuclear fuel	482	441
Other—including plant under construction	920	1,083
Total nonutility	5,671	17,596
Total property, plant and equipment	$33,331	$43,575

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, 2007 were not material. There were no significant properties under development, as defined by the SEC, excluded from amortization at December 31, 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,	2007	2006	2005
(Per mcf equivalent)			
U.S. cost center	$1.90	$1.65	$1.41
Canadian cost center	—(1)	2.19	1.82

mcf = thousand cubic feet

(1)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 as of June 30, 2007. The amortization rate for capitalized costs for our Canadian cost center as of June 2007 was $1.89 per mcf equivalent.

Volumetric Production Payment Transactions

In 2005, we received $424 million in cash for the sale of a fixed-term overriding royalty interest in certain of our natural gas reserves for the period March 2005 through February 2009. The sale reduced our proved natural gas reserves by approximately 76 billion cubic feet (bcf) in 2005. While we were obligated under the agreement 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 approximately 76 bcf of natural gas scheduled for delivery to the purchaser, we had no obligation to make up the shortfall. Cash proceeds received from this VPP transaction were recorded as deferred revenue. We recognized revenue as natural gas was produced and delivered to the purchaser. We previously entered into VPP transactions in 2004 and 2003 for approximately 83 bcf for the period May 2004 through April 2008 and 66 bcf for the period August 2003 through July 2007, respectively. The remaining deferred revenue amounts were $248 million and $510 million at December 31, 2006 and 2005, respectively. 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.

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, 2007 is as follows:

	Bath County Pumped Storage Station	North Anna Power Station	Clover Power Station	Millstone Power Station(1)
(millions, except percentages)				
Ownership interest	60.0%	88.4%	50.0%	93.5%
Plant in service	$1,013	$2,053	$ 557	$ 791
Accumulated depreciation	(415)	(998)	(141)	(141)
Nuclear fuel	—	457	—	253
Accumulated amortization of nuclear fuel	—	(356)	—	(162)
Plant under construction	10	110	1	55

(1)Represents our ownership interest in unit 3.

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 14. GOODWILL AND INTANGIBLE ASSETS

Goodwill

The changes in the carrying amount of goodwill during the year ended December 31, 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

(1) Reflects the reallocation of goodwill due to 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.*

There was no impairment of or material change to the carrying amount or segment allocation of goodwill in 2006 or 2005.

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 $115 million, $106 million and $130 million for 2007, 2006 and 2005, respectively. In 2007, we acquired $77 million of intangible assets, primarily representing software and emissions allowances, with an estimated weighted-average amortization period of approximately 10.9 years. The components of our intangible assets are as follows:

At December 31,	2007		2006	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
(millions)				
Software and software licenses	$ 591	$ 340	$ 642	$ 359
Emissions allowances	168	39	177	30
Other	262	44	235	37
Total	$1,021	$ 423	$1,054	$ 426

Annual amortization expense for these intangible assets is estimated to be $83 million for 2008, $76 million for 2009, $62 million for 2010, $35 million for 2011 and $23 million for 2012.

NOTE 15. REGULATORY ASSETS AND LIABILITIES

Our regulatory assets and liabilities include the following:

At December 31,	2007	2006
(millions)		
Regulatory assets:		
Unrecovered gas costs	$ 63	$ 11
Regulatory assets—current(1)	63	11
Unrecognized pension and other postretirement benefit costs(2)	272	135
Customer bad debts(3)	70	85
RTO start-up costs and administration fees(4)	103	74
Deferred cost of fuel used in electric generation(5)	386	72
Other postretirement benefit costs(6)	47	61
Income taxes recoverable through future rates(7)	30	46
Other	49	66
Regulatory assets—non-current	957	539
Total regulatory assets	$1,020	$550
Regulatory liabilities:		
Provision for future cost of removal(8)	623	577
Decommissioning trust(9)	487	13
Other(10)	116	31
Total regulatory liabilities	$1,226	$621

(1)Reported in other current assets.

(2)Represents unrecognized pension and other postretirement benefit costs expected to be recovered through future rates by certain of our rate-regulated subsidiaries.

(3)Instead of recovering bad debt costs through our base rates, the Public Utilities Commission of Ohio (Ohio Commission) allows us to recover all eligible bad debt expenses through a bad debt tracker. Annually, we assess the need to adjust the tracker based on the preceding year's unrecovered deferred bad debt expense. The Ohio Commission also has authorized the collection of previously deferred costs associated with certain uncollectible customer accounts from 2001 over five years, beginning in July 2004 through the tracker rider. Remaining costs to be recovered totaled $15 million at December 31, 2007.

(4)FERC has conditionally authorized our deferral of start-up costs incurred in connection with joining an RTO and ongoing administrative fees paid to PJM. We have deferred $87 million in start-up costs and administration fees and $16 million of associated carrying costs. We expect recovery from Virginia jurisdictional retail customers to commence at the end of the Virginia retail rate cap period, subject to regulatory approval.

(5)As discussed under Virginia Fuel Expenses in Note 24, 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.

(6)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.

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

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

(9)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.

(10)Includes $3 million and $7 million reported in other current liabilities in 2007 and 2006, respectively.

At December 31, 2007, approximately $659 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, RTO start-up costs and administration fees, 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 2009.

Note 16. 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 2007 were as follows:

	Amount
(millions)	
Asset retirement obligations at December 31, 2006[1]	$ 1,932
Obligations incurred during the period	18
Obligations settled during the period	(35)
Obligations relieved due to sale of non-Appalachian E&P business	(275)
Accretion	99
Other	(2)
Asset retirement obligations at December 31, 2007[1]	$ 1,737

(1) Includes $2 million and $15 million reported in other current liabilities at December 31, 2006 and 2007, respectively.

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2007 and 2006, the aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $2.9 billion and $2.8 billion, respectively.

NOTE 17. VARIABLE INTEREST ENTITIES

FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R) addresses the consolidation of VIEs. An entity is considered a VIE under FIN 46R if it does not have sufficient equity to finance its activities without assistance from variable interest holders or if its equity investors lack any of the following characteristics of a controlling financial interest:

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

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

We have long-term power and capacity contracts with 4 potential VIEs, which contain certain variable pricing mechanisms to the counterparty in the form of partial fuel reimbursement. We have concluded we are not the primary beneficiary of any of these potential VIEs. 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 $2.1 billion as of December 31, 2007. We paid $211 million, $214 million and $222 million for electric capacity and $160 million, $130 million and $159 million for electric energy to these entities for the years ended December 31, 2007, 2006 and 2005, respectively.

Our Consolidated Balance Sheet as of December 31, 2006, reflected $337 million of net property, plant and equipment and $370 million of debt, related to the consolidation, in accordance with FIN 46R, of a variable interest lessor entity through which we had financed and leased a power generation plant for our utility operations. The debt was non-recourse to us and was secured by the entity's property, plant and equipment. The lease under which we operated the power generation facility terminated in August 2007 and we took legal title to the facility through the repayment of the lessor's related debt.

As discussed in Note 28, DCI holds an investment in the subordinated notes of a third-party CDO. In June 2006, the CDO entity's equity investor withdrew its capital, which required a redetermination of whether the CDO entity is a VIE under FIN 46R. We concluded that the CDO entity is a VIE and that DCI is the primary beneficiary of the CDO entity, which we have consolidated in accordance with FIN 46R.

NOTE 18. SHORT-TERM DEBT AND CREDIT AGREEMENTS

As a result of the merger of CNG with Dominion in June 2007, all of CNG's former credit facilities have been assumed by Dominion. We use short-term debt, primarily commercial paper, to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, we utilize cash and letters of credit to fund collateral requirements under our commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels, our credit quality and the credit quality of our counterparties. At December 31, 2007, we had committed lines of credit totaling $4.9 billion. These lines of credit support commercial paper borrowings and letter of credit issuances. At December 31, 2007 and 2006, we had the following commercial paper, bank loans, and letters of credit outstanding, as well as capacity available under our credit facilities:

	Facility Limit	Outstanding Commercial Paper	Outstanding Bank Borrowings	Outstanding Letters of Credit	Facility Capacity Available
(millions)					
2007					
Five-year joint revolving credit facility(1)	$3,000	$ 757	$ —	$229	$2,014
Five-year	1,700	—	1,000	1	699

Source: DOMINION RESOURCES I, 10-K, February 28, 2008

Dominion credit facility(2)					
Five-year Dominion bilateral facility(3)	200	—	—	—	200
Totals	$4,900	$ 757	$ 1,000	$230	$2,913
2006					
Five-year joint revolving credit facility(1)	$3,000	$ 1,759	$ —	$236	$1,005
Five-year Dominion credit facility(2)	1,700	—	500	484	716
Five-year Dominion bilateral facility(3)	200	—	—	—	200
364-day credit facility(4)	1,050	—	—	—	1,050
Totals	$5,950	$ 1,759	$ 500	$720	$2,971

(1)The $3.0 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. The weighted-average interest rates of the outstanding commercial paper supported by this facility were 5.66% and 5.41% at December 31, 2007 and 2006, respectively.

(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. The weighted-average interest rates of the outstanding bank borrowing supported by this facility were 5.69% and 5.76% at December 31, 2007 and 2006, respectively.

(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 $1.05 billion 364-day credit facility was used to support the issuance of letters of credit and commercial paper by our former CNG consolidated subsidiary to fund collateral requirements under its gas and oil hedging program. The facility was entered into in February 2006 and terminated in February 2007.

In addition to the facilities above, we also entered into a $100 million bilateral credit facility in August 2004 that terminates in August 2009. At December 31, 2007, there were no letters of credit outstanding under this facility. At December 31, 2006, outstanding letters of credit under this facility totaled $100 million. At December 31, 2006, we also had a $100 million three-year credit facility entered into in June 2004 that terminated in June 2007. At December 31, 2006, outstanding letters of credit under this facility totaled $25 million.

NOTE 19. LONG-TERM DEBT

At December 31,	2007 Weighted-Average Coupon(1)	2007	2006
(millions, except percentages)			
Dominion Resources, Inc.:			
Unsecured Senior and Medium-Term Notes:			
4.125% to 8.125%, due 2008 to 2012	5.38%	$ 2,262	$ 3,050
5.0% to 7.195%, due 2013 to 2035(2)	5.61%	3,047	3,110
Variable rates, due 2007 and 2008	5.53%	400	1,400
Unsecured Convertible Senior Notes, 2.125%, due 2023(3)		220	220
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts, 7.83% to 8.4%, due 2027 to 2031	7.85%	268	516
Enhanced Junior Subordinated Notes, 6.3% to 7.5%, due 2066	6.75%	800	800
Unsecured Debentures and Senior Notes(4):			
6.0% to 6.875%, due 2007 to 2011	6.22%	720	1,500
5.0% to 6.875%, due 2013 to 2027	5.28%	711	1,200
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.8%, due 2041(4)		—	206
Virginia Electric and Power Company:			
Secured First and Refunding Mortgage Bonds, 7.625%, due 2007(5)		—	215
Secured Bank Debt, Variable rate, due 2007(6)		—	370
Unsecured Senior and Medium-Term Notes:			
4.5% to 5.73%, due 2007 to 2012	5.03%	950	1,000
4.75% to 8.625%, due 2013 to 2037	5.83%	3,385	1,748
Unsecured Callable and Puttable Enhanced Securities[SM], 4.10%, due 2038(7)		225	225
Tax-Exempt Financings:(8)			
Variable rate, due 2008	3.86%	60	60
Variable rates, due 2015 to 2027	3.80%	137	137
4.95% to 7.65%, due 2007 to 2010	5.42%	205	232
4.25% to 7.55%, due 2014 to 2031	5.26%	223	263
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.375%, due 2042		412	412
Dominion Energy, Inc.:			
Secured Senior Note, 7.33%, due 2020(9)		204	213
Tax-Exempt Financing, 5.0%, due 2036		47	47
Dominion Capital, Inc.:			
Notes, 12.5%, due 2007		—	4
Senior Revolving Notes, Variable rate, due 2017(10)	5.71%	75	—
Senior Note, Variable rate, due 2017(10)	5.66%	385	385
		14,736	17,313
Fair value hedge valuation(11)		9	(6)
Amounts due within one year(12)	5.19%	(1,477)	(2,478)
Unamortized discount and premium, net		(33)	(38)
Total long-term debt		$13,235	$14,791

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2007.

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

(3) Convertible into a combination of cash and 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, 2006, December 15, 2008, December 15, 2013, or December 15, 2018, these securities are subject to redemption at 100% of the principal amount plus accrued interest. On December 15, 2006 less than $100 thousand of the debt was redeemed due to holders exercising their put option.

(4) Represents debt assumed by DRI from the merger of our former CNG consolidated subsidiary.

(5) Substantially all of Virginia Power's property ($13.1 billion at December 31, 2007) is subject to the lien of the mortgage securing its First and Refunding Mortgage Bonds. Although there are no publicly issued bonds outstanding as of December 31, 2007, we may issue additional bonds in the future.

(6) Represented debt associated with certain special purpose lessor entities consolidated in accordance with FIN 46R. The debt was nonrecourse to us and was secured by the entities' property, plant and equipment, which totaled $337 million at December 31, 2006. This debt was repaid in August 2007, when the lease terminated.

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

(8) These financings relate to certain pollution control equipment at Virginia Power's generating facilities. The variable rate tax-exempt financings are supported by a $200 million five-year credit facility 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.

(9) Represents debt associated with our Kincaid power station. The debt is non-recourse to us and is secured by the facility's assets ($557 million at December 31, 2007) and revenue.

(10)As discussed in Note 28, in June 2006, DCI began consolidating a CDO entity, in accordance with FIN 46R. The debt is nonrecourse to us.

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

(12)Includes $1 million of net unamortized discount and fair value hedge valuation.

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, 2007, were as follows:

	2008	2009	2010	2011	2012	Thereafter	Total
(millions, except percentages)							
Secured Senior Notes	$ 10	$ 11	$ 12	$ 13	$ 13	$ 145	$ 204
Unsecured Senior Notes (including Medium-Term Notes)	1,315	313	822	484	1,470	7,305	11,709
Unsecured Callable and Puttable Enhanced Securities[SM]	—	—	—	—	—	225	225
Tax-Exempt Financings	153	111	1	—	—	392	657
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts	—	—	—	—	—	681	681
Enhanced Junior Subordinated Notes	—	—	—	—	—	800	800
Other	—	—	—	—	—	460	460
Total	$1,478	$ 435	$ 835	$ 497	$1,483	$ 10,008	$14,736
Weighted-average coupon	5.19%	5.36%	5.39%	6.35%	5.62%	5.75%	

We repaid $5.5 billion of long-term debt and notes payable during 2007, which includes the completion of a debt tender offer repurchasing $2.5 billion of our debt securities in July 2007. We recognized charges of $242 million ($148 million after-tax) primarily in connection with the early redemption of this debt. Of this amount, $234 million ($143 million after-tax) was recorded in interest and related charges in our Consolidated Statement of Income.

Our short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2007, 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* (EITF 04-8). We exchanged the outstanding notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. 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, 2007, the conversion rate had been adjusted to 27.5294, primarily due to individual dividend payments above the level paid at issuance.

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 ($43.51 as of February 27, 2008) 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 Investors Service (Moody's) is below Baa3 and by Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies, Inc. (Standard & Poor's), is below BBB- or the ratings are discontinued for any reason.

As of December 31, 2007, the closing price of our common stock was equal to $44.16 per share or higher for at least 20 out of the last 30 consecutive trading days. Therefore, the senior notes are eligible for conversion during the first quarter of 2008. 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. 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, 2013 or 2018, or if we undergo certain fundamental changes. We continue to classify these senior notes as long-term debt in our Consolidated Balance Sheet since we have the intent and ability to refinance them on a long-term basis.

Equity-Linked Securities

In 2002, we issued 6.6 million equity-linked debt securities, consisting of stock purchase contracts and senior notes. Total net proceeds were $320 million. Long-term debt of $330 million and an equity charge of $36 million were recorded in our Consolidated Balance Sheet related to the issuance.

The stock purchase contracts obligated the holders to purchase shares of our common stock from us by May 2006. The purchase price, recast to reflect our November 2007 stock split, was $25 and the number of shares to be purchased was determined under a formula based upon the average closing price of our common stock near the settlement date. The senior notes, or treasury securities in some instances, were pledged as collateral to secure the purchase of common stock under the related stock purchase contracts. The holders were given the option to either satisfy their obligations under the stock purchase contracts by allowing the senior notes to be remarketed with the proceeds being paid to us as consideration for the purchase of stock or continue to hold the senior notes and use other resources as consideration for the purchase of stock under the stock purchase contracts. In February 2006, we successfully remarketed the senior notes related to our equity-linked debt securities. The senior notes, which will mature in 2008, now carry an annual interest rate of 5.687%; prior to the remarketing, the notes carried an annual interest rate of 5.75%.

Prior to conversion, we made quarterly interest payments on the senior notes and quarterly payments on the stock purchase contracts. Prior to conversion, we recorded the present value of the stock purchase contract payments as a liability, offset by a charge to common stock in shareholders' equity. The stock purchase contracts carried an annual interest rate of 3.00% prior to their settlement in May 2006, by issuance of 9 million shares, recast to reflect the impact of our November 2007 stock split, of our common stock. Interest payments on the senior notes are recorded as interest expense and stock purchase contract payments were charged against the liability. Prior to conversion, accretion of the stock purchase contract liability was recorded as interest expense. In calculating diluted EPS, we applied the treasury stock method to the equity-linked debt securities. These securities did not have a significant effect on diluted EPS in 2006 or 2005.

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 July and August 2007, we redeemed approximately 240 thousand units of the $250 million 8.4% Dominion Capital Trust III debentures due January 15, 2031. The securities were redeemed at a 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 debentures 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 debentures 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, 2007:

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
August 2002	Virginia Power Capital Trust II(3)	16,000	7.375%	400	12.4

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.

(3)$412 million—Virginia Power 7.375% Debentures due 7/30/2042.

Distribution payments on the trust preferred securities are considered to be fully and unconditionally guaranteed by the respective parent company that issued the debt instruments held by each trust, when all of the related agreements are taken into consideration. Each guarantee agreement only provides for the guarantee of distribution payments on the relevant trust preferred securities to the extent that the trust has funds legally and immediately available to make distributions. The trust's ability to pay amounts when they are due on the trust preferred securities is dependent solely upon the payment of amounts by Dominion or Virginia Power 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, the company that issued them may not make distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, the company that issued them may not make any payments on, 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 20. 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, 2007 or 2006.

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, 2007 and 2006. 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, 2007:

Dividend	Issued and Outstanding Shares	Entitled Per Share Upon Liquidation
	(thousands)	
$5.00	107	$112.50
4.04	13	102.27
4.20	15	102.50
4.12	32	103.73
4.80	73	101.00
7.05	500	102.12(1)
6.98	600	102.10(2)
Flex MMP 12/02, Series A	1,250	100.00(3)
Total	2,590	

(1)Through 7/31/2008; $101.77 commencing 8/1/2008; amounts decline in steps thereafter to $100.00 by 8/1/2013.

(2)Through 8/31/2008; $101.75 commencing 9/1/2008; 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 21. Shareholders' Equity

Issuance of Common Stock

In 2007, we received cash proceeds of $226 million for 7.6 million shares issued in connection with the exercise of employee stock options. During 2007, we purchased our common stock on the open market with the proceeds received through Dominion Direct® (a dividend reinvestment and open enrollment direct stock purchase plan) and employee savings plans, rather than having additional new common shares issued. In January 2008, we began issuing additional new common shares to be used for these programs.

Repurchases of Common Stock

In 2007, we repurchased 129.0 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.

In December 2006, we entered into a prepaid accelerated share repurchase agreement (ASR) with a financial institution as the counterparty. Under the ASR, we would receive between 11.2 million and 13.0 million shares in exchange for the prepayment. At the time of execution of the ASR, we made a prepayment of $500 million and the counterparty initially delivered approximately 10.1 million shares to us. The final number of shares to be delivered to the Company was determined by the volume weighted average price of our common stock over the period commencing on December 12, 2006 and terminating on May 16, 2007. In May 2007, the counterparty delivered approximately 1.6 million additional shares to us in completion of the ASR.

At December 31, 2007, 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.

Shares Reserved for Issuance

At December 31, 2007, we had a total of 46 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,	2007	2006
(millions)		
Net unrealized losses on derivatives—hedging activities, net of tax of $30 and $266, respectively	$ (42)	$(422)
Net unrealized gains on investment securities, net of tax of $116 and $187, respectively	180	282
Net unrecognized pension and other postretirement benefit costs, net of tax of $149 and $239, respectively	(150)	(335)
Foreign currency translation adjustments	—(1)	50
Total accumulated other comprehensive loss	$ (12)	$(425)

(1)Decrease is due to the sale of our Canadian E&P business in June 2007.

Stock-Based Awards

In April 2005, our shareholders approved the 2005 Incentive Compensation Plan (2005 Incentive Plan) for employees and the Non-Employee Directors Compensation Plan (Non-Employee Directors Plan). The 2005 Incentive Plan permits stock-based awards that include restricted stock, performance grants, goal-based stock and stock options, and the Non-Employee Directors

Plan permits restricted stock and stock options. Under provisions of both plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms are set at the discretion of the Compensation, Governance and Nominating (CGN) Committee of the Board of Directors or the Board of Directors itself, as provided under each individual plan. At December 31, 2007, approximately 29 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, 2007, 2006 and 2005 include $57 million, $31 million and $25 million, respectively, of compensation costs and $21 million, $11 million and $10 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in our Consolidated Statements of Income.

Stock Options

The following table provides a summary of changes in amounts of stock options outstanding as of and for the years ended December 31, 2007, 2006 and 2005. No options were granted under any plan in 2007, 2006 or 2005.

	Shares	Weighted-average Exercise Price	Weighted-average Remaining Contractual Life	Aggregated Intrinsic Value (1)
	(thousands)		(years)	(millions)
Outstanding at December 31, 2004	27,616	$ 30.09		
Exercisable at December 31, 2004	21,536	$ 30.01		
Exercised	(11,158)	$ 29.90		$ 77
Forfeited/expired	(30)	$ 31.27		
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	2.8	$ 120

(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 $226 million, $54 million and $335 million in the years ended December 31, 2007, 2006 and 2005, 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, 2007, 2006 and 2005:

	Shares	Weighted-average Grant Date Fair Value

	(thousands)		
Nonvested at December 31, 2004	1,920	$	30.17
Granted	498		37.26
Vested	(60)		31.23
Cancelled and forfeited	(96)		31.64
Nonvested at December 31, 2005	2,262	$	31.64
Granted	675		35.22
Vested	(361)		30.88
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

As of December 31, 2007, unrecognized compensation cost related to nonvested restricted stock awards totaled $25 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 $30 million, $14 million and $2 million in 2007, 2006 and 2005, 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 value of Dominion stock and the applicable federal, state and local tax withholding rates.

Goal-Based Stock

Goal-based stock awards are generally granted to key non-officer employees on an annual basis. Goal-based stock awards were also granted in lieu of cash-based performance grants to certain officers who had not achieved a certain level of share ownership. The issuance of awards is based on the achievement of multiple performance metrics during a two-year period, including return on invested capital and total shareholder return relative to that of a peer group of companies. The actual number of shares issued will vary between zero and 200% of targeted shares depending on the level of performance metrics achieved. The fair value of goal-based stock is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of goal-based stock activity for the years ended December 31, 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

At December 31, 2007, the targeted number of shares expected to be issued under these awards was approximately 289 thousand. In January 2008, the CGN determined that the total number of shares expected to be issued under the goal-based stock awards is 359 thousand, based on the actual performance against metrics, as amended in January 2008, established for those awards whose performance period ended on December 31, 2007.

As of December 31, 2007, 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

In April 2006, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2008 and is based on the achievement of two performance metrics during 2006 and 2007: return on invested capital and total shareholder return relative to that of a peer group of companies. Actual payout will vary between zero and 200% of the targeted amount, depending on the level of performance metrics achieved. At December 31, 2007, the targeted amount of the grant was $13 million, however the actual payout will be $18 million based on the performance metrics achieved.

In April 2007, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2009 and is based on the achievement of two performance metrics during 2007 and 2008: return on invested capital and total shareholder return relative to that of a peer group of companies.

At December 31, 2007, the targeted amount of the grant is $14 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved.

At December 31, 2007, a liability of $25 million has been accrued for these awards.

Note 22. 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, 2007, 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, 2007.

See Note 19 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 23. 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 generally contribute annually an amount that is in accordance with the provisions of the Employment Retirement Income Security Act of 1974. The pension program also provides benefits to certain retired executives under company-sponsored nonqualified employee benefit plans. Certain of these nonqualified plans are funded through contributions to a grantor trust.

We provide retiree health care and life insurance benefits with annual employee premiums based on several factors such as age, retirement date and years of service.

In 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 have determined that the prescription drug benefit offered under our other postretirement benefit plans is at least actuarially equivalent to Medicare Part D and therefore, we expect to receive the federal subsidy offered under the Medicare Act.

We 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 pension plan assets, a component of net periodic pension cost. The market-related value recognizes changes in fair value on a straight-line basis over a four-year period. Changes in fair value are measured as the difference between the expected and actual plan asset returns, including dividends, interest and realized and unrealized investment gains and losses.

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,	2007	2006	2007	2006
(millions)				
Change in benefit obligation:				
Benefit obligation at beginning of year	$3,666	$3,834	$ 1,297	$ 1,622
Service cost	112	124	55	72
Interest cost	222	210	77	81
Benefits paid	(164)	(175)	(69)	(72)
Actuarial (gain) loss during the year(1)	(139)	(329)	125	(395)
Plan amendments	4	2	(14)	(11)
Curtailments	(8)	—	(7)	—
Benefit obligation at end of year	$3,693	$3,666	$ 1,464	$ 1,297
Change in plan assets:				
Fair value of plan assets at beginning of year	$4,793	$4,360	$ 909	$ 794
Actual return on plan assets	461	589	59	85
Contributions	8	19	25	68
Benefits paid from plan assets	(164)	(175)	(33)	(38)
Fair value of plan assets at end of year	$5,098	$4,793	$ 960	$ 909
Funded status at end of year	$1,405	$1,127	$ (504)	$ (388)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	$1,544	$1,240	$ 21	$ 6
Other current liabilities	(29)	(2)	(2)	—
Other deferred credits and other liabilities	(110)	(111)	(523)	(394)
Net amount recognized	$1,405	$1,127	$ (504)	$ (388)

(1)The actuarial gains for pension benefits primarily resulted from an increase in the discount rate for 2007 and an increase in the discount rate and the expected retirement age for 2006. The 2006 actuarial gain for other postretirement benefits primarily resulted from an increase in the discount rate and a decrease in expected future benefit claims.

The accumulated benefit obligation (ABO) for all of our defined benefit pension plans was $3.2 billion each at December 31, 2007 and 2006. 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.

We do not expect any pension or postretirement benefit plan assets to be returned to the Company during 2008.

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,	2007	2006	2007	2006
(millions)				
Benefit obligation	$ 139	$ 131	$ 1,328	$ 1,159
Fair value of plan assets	—	18	803	765

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,	2007	2006
(millions)		

Accumulated benefit obligation	$ 84	$ 65
Fair value of plan assets	—	—

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

(millions)	Pension Benefits	Other Postretirement Benefits
2008	$ 194	$ 83
2009	177	90
2010	191	97
2011	196	104
2012	212	110
2013-2017	1,341	637

The above benefit payments for other postretirement benefit plans are expected to be offset by Medicare Part D subsidies of approximately $5 million annually for 2008 and 2009, approximately $6 million annually for the period 2010 through 2012 and approximately $39 million during the period 2013 through 2017.

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. 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,	2007		2006		2007		2006	
	Fair Value	% of Total	Fair Value	% of Total	Fair Value	% of Total	Fair Value	% of Total
(millions, except percentages)								
Equity securities:								
U.S.	$1,767	35%	$1,491	31%	$384	40%	$369	41%
International	757	15	751	16	107	11	106	11
Debt securities	1,228	24	1,356	28	347	36	335	37
Real estate	406	8	376	8	31	3	25	3
Other	940	18	819	17	91	10	74	8
Total	$5,098	100%	$4,793	100%	$960	100%	$909	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,	2007	2006	2005	2007	2006	2005
(millions)						
Service cost	$ 112	$ 124	$ 110	$ 55	$ 72	$ 64
Interest cost	222	210	201	77	81	83
Expected return on plan assets	(391)	(357)	(341)	(71)	(62)	(51)
Amortization of prior service (credit) cost	4	4	3	(6)	(4)	(1)
Amortization of transition obligation	—	—	—	3	3	3
Amortization of net loss	37	89	77	6	24	19
Settlements and curtailments[1]	11	12	—	(3)	—	—
Plan amendments[2]	4	—	—	9	—	—
Net periodic benefit (credit) cost	$ (1)	$ 82	$ 50	$ 70	$ 114	$ 117
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and regulatory liabilities:						
Current year net actuarial (gain) loss	$(209)	$ —	$ —	$ 137	$ —	$ —
Prior service (credit) cost	3	—	—	(8)	—	—
Transition asset	—	—	—	(17)	—	—
Settlements and curtailments	(21)	—	—	—	—	—
Less amounts included in net periodic benefit (credit) cost:						
Amortization of net loss	(37)	—	—	(6)	—	—
Amortization of prior service credit (cost)	(4)	—	—	6	—	—
Amortization of transition obligation	—	—	—	(3)	—	—
Plan amendments	—	—	—	(2)	—	—
Change in additional minimum liability	—	(17)	(7)	—	—	—
Total recognized in other comprehensive income and regulatory assets and regulatory liabilities	$(268)	$ (17)	$ (7)	$ 107	$ —	$ —

(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.

The components of AOCI and regulatory assets and regulatory liabilities that have not been recognized as components of periodic benefit (credit) cost:

	Pension Benefits		Other Postretirement Benefits	
As of December 31,	2007	2006	2007	2006
(millions)				
Transition obligation	$ —	$ —	$ —	$ 20
Net actuarial loss	365	631	185	57
Prior service (credit) cost	23	25	(40)	(39)
Total[1]	$ 388	$ 656	$ 145	$ 38

(1)Of the $388 million and $145 million related to pension benefits and other postretirement benefits, respectively, as of December 31, 2007, $183 million and $116 million, respectively, are included in AOCI. Of the $656 million and $38 million related to pension benefits and other postretirement benefits, respectively, as of December 31, 2006, $561 million and $13 million, respectively, are included in AOCI.

The following table provides the components of AOCI, regulatory assets and regulatory liabilities as of December 31, 2007 that are expected to be amortized as components of periodic benefit cost in 2008:

	Pension Benefits	Other Postretirement Benefits
(millions)		
Net actuarial loss	$ 7	$ 8
Prior service (credit) cost	4	(6)

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

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	2007	2006	2005	2007	2006	2005
Discount rate	6.20%	5.60%	6.00%	6.10%	5.50%	6.00%
Expected return on plan assets	8.75%	8.75%	8.75%	8.00%	8.00%	8.00%
Rate of increase for compensation	4.79%	4.70%	4.70%	4.70%	4.70%	4.70%

Medical cost trend rate(1)	9.00%	9.00%	9.00%

(1)The medical cost trend rate for 2007 is assumed to gradually decrease to 5.00% by 2011 and continues at that rate for years thereafter.

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

	Pension Benefits		Other Postretirement Benefits	
At December 31,	**2007**	2006	**2007**	2006
Discount rate	**6.60%**	6.20%	**6.50%**	6.10%
Rate of increase for compensation	**4.79%**	4.79%	**4.70%**	4.70%

We determine the expected long-term rates of return on plan assets for pension plans and other postretirement benefit plans by using a combination of:

- Historical return analysis to determine expected future risk premiums;
- Forward-looking return expectations derived from the yield on long-term bonds and the price earnings ratios of major stock market indices;
- Expected inflation and risk-free interest rate assumptions; and
- The types of investments expected to be held by the plans.

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 2007	$ 20	$ (17)
Effect on postretirement benefit obligation at December 31, 2007	184	(149)

In addition, we sponsor defined contribution thrift-type savings plans. During 2007, 2006 and 2005, we recognized $37 million, $36 million and $33 million, respectively, as contributions to these plans.

Certain regulatory authorities have held that amounts recovered in utility customers' rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, certain of our subsidiaries fund postretirement benefit costs through Voluntary Employees' Beneficiary Associations (VEBAs). Our remaining subsidiaries do not prefund postretirement benefit costs but instead pay claims as presented. We expect to contribute $32 million to the Dominion VEBAs in 2008.

Note 24. 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, 2007, 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:

	2008	2009	2010	2011	2012	Thereafter	Total
(millions)							
Purchased electric capacity(1)	$383	$364	$349	$348	$352	$ 1,857	$3,653

(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, 2007, the present value of our total commitment for capacity payments is $2.4 billion. Capacity payments totaled $410 million, $437 million and $472 million, and energy payments totaled $360 million, $291 million and $378 million for 2007, 2006 and 2005, 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, 2007 are as follows:

	2008	2009	2010	2011	2012	Thereafter	Total
(millions)							
[illegible]	$ 81	$ 72	$ 58	$ 50	$ 41	$ 151	$453

Rental expense totaled $185 million, $178 million and $160 million for 2007, 2006 and 2005, respectively, the majority of which is reflected in other operations and maintenance expense.

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 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

Mt. Storm Wind Farm

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 construction phases totaling 264 Mw. The first phase (164 Mw) is expected to become fully operational by June 2008 and the second phase is expected to be fully operational by December 2008. During 2007, we made cash contributions of $67 million to NedPower and expect to contribute an additional $57 million in 2008. The remaining cost of both phases is expected to be funded by NedPower through non-recourse construction financing with third-party banks.

Fowler Ridge Wind Farm

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. The facility is expected to be built in two phases and generate a total of 750 Mw. We will jointly own 650 Mw with BP and BP will retain sole ownership of 100 Mw. We have committed to contribute approximately $340 million of cash at various dates through January 2009, which includes our initial investment and funding for the development of the first 300 Mw phase. Construction of the second 350 Mw phase could begin as early as 2009, with funding to be contributed to the joint venture to maintain 50/50 ownership between the partners. Our ultimate funding requirements may decrease to the extent that the joint venture obtains non-recourse construction and term financing.

Environmental Matters

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

To the extent environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 2008, in excess of the level currently included in Virginia jurisdictional rates, our results of operations could decrease. After that date, we may seek recovery through rates.

Superfund Sites

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

Other

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 Nuclear Regulatory Commission (NRC) requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Our 2007 calculation for the NRC minimum financial assurance amount, aggregated for our nuclear units, was $2.4 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.

Nuclear Insurance

The Price-Anderson Act provides the public up to $10.8 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

At December 31, 2007, we had issued the following subsidiary guarantees:

	Stated Limit	Value(1)
(millions)		
Subsidiary debt(2)	$ 48	$ 48
Commodity transactions(3)	2,985	326
Lease obligation for power generation facility(4)	917	917
Nuclear obligations(5)	383	302
Other	341	192
Total	$ 4,674	$1,785

(1)Represents the estimated portion of the guarantee's stated limit that is utilized as of December 31, 2007 based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by our subsidiaries, the value includes the recorded amount.

(2)Guarantees of debt of a DEI subsidiary. In the event of default by the subsidiary, we would be obligated to repay such 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. In addition to the guarantees listed above, we have also agreed to provide up to $150 million and $60 million to two DEI subsidiaries, to pay 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.

Additionally, as of December 31, 2007, we had purchased $56 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $230 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, 2007, we believe future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

We have entered into other types of contracts that require indemnifications, such as purchase and sale agreements and financing agreements. These agreements may include, but are not limited to, indemnifications around certain title, tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price and is typically limited in duration depending on the nature of the indemnified matter. Since January 1, 2005, we have entered into sale agreements with maximum exposure related to the collective purchase prices of approximately $15 billion. We believe that it is improbable 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 Restructuring Act and Fuel Factor Amendments

On July 1, 2007, legislation amending the Virginia Electric Utility Restructuring Act (the Restructuring Act) and the fuel factor became effective, which significantly changes electricity regulation in Virginia. Prior to the Restructuring Act, our base rates in Virginia were capped at 1999 levels until December 31, 2010. The Restructuring Act ends capped rates two years early, on December 31, 2008. After capped rates end, retail choice will be eliminated for all but 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 be permitted to purchase renewable energy from competitive suppliers if the incumbent electric utility does not offer a renewable energy tariff. Also after the end of capped rates, the Virginia Commission will set our base rates under a modified cost-of-service model. Among other features, the new model provides for the Virginia Commission to:

- Initiate a base rate case during the first six months of 2009, reviewing the 2008 test year, as a result of which the Virginia Commission:
  - shall establish a return on equity (ROE) no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earnings more than 50 basis points below the established ROE; or
  - may reduce rates prospectively upon completion of the 2009 review or, alternatively, order a credit to customers if we are found to have test year earnings of more than 50 basis points above the established ROE.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - shall establish an ROE no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with

certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - after 2010, authorize an increased ROE on overall rate base upon achieving the goals established for the renewable energy portfolio standard programs. Such increased ROE would be in lieu of any increased or decreased ROE from the preceding paragraph, unless there has been an increase to the ROE awarded under the preceding paragraph that is higher than the renewable energy portfolio standard increase; and
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earned, during the test period, more than 50 basis points below the then currently established ROE; or
  - may order a credit to customers if we are found to have earned, during the test period, more than 50 basis points above the then currently established ROE, and reduce rates if we are found to have such excess earnings during two consecutive biennial review periods.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service and energy efficiency, conservation, and renewable energy programs; and
- Authorize an enhanced ROE on new capital expenditures as a financial incentive for construction of certain major generation projects.

The legislation 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*.

As discussed previously, the legislation provides for the Virginia Commission to initiate a base rate case during the first six months of 2009, as a result of which the Virginia Commission may reduce rates or alternatively, order a credit to customers if we are found to have earnings more than 50 basis points above the established 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.

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 have increased considerably since 2004, 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 on 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. Under these amendments, our fuel factor increase as of July 1, 2007 was limited to an amount that results 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 to be deferred and subsequently recovered subject to Virginia Commission approval, without interest, during the period commencing July 1, 2008 and ending June 30, 2011.

Stranded Costs

Stranded costs are generation-related costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market. In the past, our exposure to potential stranded costs included long-term power purchase contracts that could ultimately be determined to be above market prices; generating plants that could possibly become uneconomical in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits. Capped electric retail rates provided an opportunity to recover our potential stranded costs, depending on market prices of electricity and other factors. Recovery of our potential stranded costs was subject to numerous risks even in the capped-rate environment. Those risks included, among others, exposure to long-term power purchase commitment losses, future environmental compliance requirements, changes in certain tax laws, nuclear decommissioning costs, increased fuel costs, inflation, increased capital costs and recovery of certain other items. However, with the return to a modified cost-of-service rate model under the 2007 Virginia Restructuring Act Amendments, our exposure to potential stranded costs and the risk of non-recovery will be eliminated.

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 change under annual fuel cost adjustment proceedings.

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 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%.